

THE RIGHT MIX

ANNUAL REPORT 2015

ON THE COVER

Wind turbines whirl as the sun sets over the Pleasant Valley Wind Farm near Austin, Minn., one of two wind farms Xcel Energy purchased in 2015. Pleasant Valley is expected to generate enough wind energy to power 105,000 homes. As the nation's No. 1 utility wind energy provider for 11 consecutive years, we are developing The Right Mix of energy sources to provide safe, clean, reliable energy at a competitive price for years to come.

COMPANY DESCRIPTION

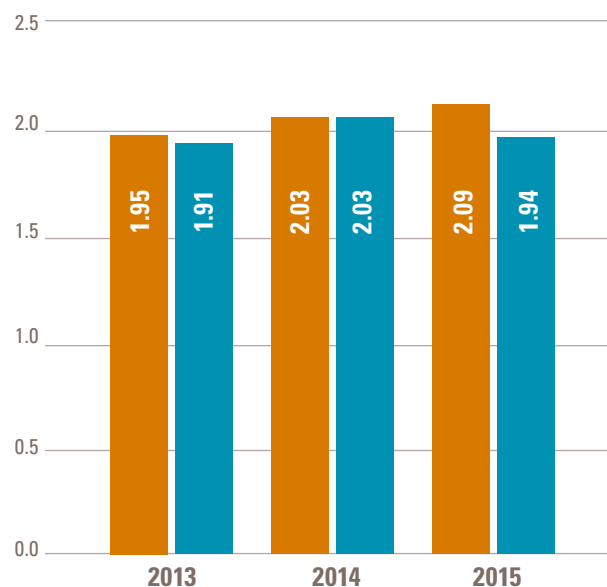
Xcel Energy is a major U.S. electric and natural gas company with annual revenues of \$11 billion. Based in Minneapolis, Minn., the company operates in eight states and provides a comprehensive portfolio of energy-related products and services to 3.5 million electricity customers and 2 million natural gas customers.

FINANCIAL HIGHLIGHTS

	2014	2015
Ongoing earnings per share	2.03	2.09
Total GAAP earnings per share	2.03	1.94
Dividends annualized	1.20	1.28
Stock price (close)	35.92	35.91
Assets (millions)	36,958	39,054
Book value per common share	20.20	20.89

XCEL ENERGY EARNINGS PER SHARE

Dollars per share (diluted)



■ Ongoing earnings per share*

■ GAAP (generally accepted accounting principles) earnings per share

*A reconciliation to GAAP earnings per share is located in Item 7 of the Form 10-K.

Some sections in this annual report, including the letter to shareholders, contain forward-looking statements. For a discussion of factors that could affect operating results, please see the management's discussion and analysis listed in the table of contents of the Form 10-K.



Letter to Shareholders

Ben Fowke
Chairman, President and CEO

Dear Fellow Shareholders:

Xcel Energy remains well positioned to deliver the energy solutions our customers need and value in a dynamic, rapidly-changing industry. 2015 was another excellent year in which we achieved strong financial and operational performance and executed well on our strategies to meet the changing needs of our stakeholders, position us for success and build value for you.

We chose **The Right Mix** as the theme of this year's report to illustrate the balance we need to succeed in all aspects of our business. Whether blending renewables and traditional fuel sources within our energy portfolio, managing customer costs while ensuring quality service, advocating for regulatory frameworks to better meet customer and community needs or attracting the best talent to help move our enterprise forward, we are constantly striving for The Right Mix.

Solid financial results

Year after year we have met or exceeded our financial targets, and 2015 was no exception. We reported ongoing earnings of \$2.09 per share, compared with \$2.03 per share in 2014. We generated \$984 million in net income, a solid result considering some adverse weather and regulatory headwinds we faced last year.

2015 was the 11th consecutive year we have met or exceeded our earnings guidance and, since 2005, we have achieved annual ongoing earnings growth of 6.2 percent. I am very proud of our strong, consistent financial performance.

We also increased your dividend for the 12th consecutive year, by 6.7 percent in 2015. We raised our dividend growth guidance to the 5 to 7 percent range in 2015, reflecting the ongoing confidence we have in our business strategy and financial flexibility.

Performance over time is proof of our ability to meet your expectations, but reaching challenging benchmarks also illustrates financial strength. Xcel Energy produced the fourth-highest total shareholder return among our peer group (3.8 percent for 2015) in a year that the average peer group performance was negative (-4.5 percent).

We were honored that *Forbes* magazine named Xcel Energy to its list of The 100 Most Trustworthy Companies in America for our consistent demonstration of transparent accounting practices and solid corporate governance. With a successful year behind us and solid prospects for the coming year, we are reaffirming our 2016 ongoing earnings guidance of \$2.12 to \$2.27 per share.

Leading the way with clean energy

Nowhere is The Right Mix more clear than in our energy supply. That includes retiring and repowering aging coal plants with natural gas, increasing our wind portfolio through additional ownership and power purchase agreements, investing in large-scale solar and maintaining our nuclear operations.

Xcel Energy will, as we always have, work with our states and stakeholders on sound plans to create sustainable and affordable energy futures. This approach will not only ensure compliance with existing and new environmental regulations, but also take advantage of new technologies, recognize evolving customer needs and continue to drive improvements in how we produce and deliver energy.

We filed a bold resource plan in the Upper Midwest to reduce carbon dioxide emissions 60 percent (compared to 2005 levels) by 2030. In Colorado, we are on schedule and budget for the Clean Air-Clean Jobs project to retire several aging coal facilities and transition to natural gas, as we reduce emissions across the state. These plans have been



Tony Mallizzio and Chris Hogg are part of the team overseeing the Pleasant Valley Wind Farm near Austin, Minn., one of two wind farms Xcel Energy purchased in 2015. The 200-megawatt project is part of our plan to significantly expand our wind portfolio.



Limon III wind farm supplies power for customers in Colorado.

EXPANDING OUR WIND PORTFOLIO THROUGH AN OWNERSHIP STAKE

As the No. 1 utility wind energy provider for the 11th consecutive year, Xcel Energy is continuing to build a strong portfolio of owned wind resources to bring value to both our customers and shareholders.

We closed 2015 with the purchase of two new wind farms: the Pleasant Valley Wind Farm near Austin, Minn., and the Border Wind Farm in Rolette County, N.D. These additions increased wind capacity by 20 percent in the Upper Midwest and are expected to generate enough clean electricity to power more than 180,000 homes.

Xcel Energy is also building the Courtenay Wind Farm in central North Dakota, which is scheduled to begin powering homes and businesses before the end of 2016. Taking an active ownership in building or buying wind farms positions the company to deliver 35 percent of renewable energy to our Upper Midwest customers by 2030.

Wind continues to play an increasing role in our energy portfolio. Our Colorado energy system has the capacity for more than 2,500 megawatts of wind generation, enough to power 1.3 million average-size homes for a year. We set a record for wind generation in 2015 when more than half of our Colorado customers' power for an entire day came from wind energy, and met nearly 20 percent of overall electric demand for the year with wind power. We are also adding to our wind portfolio in Texas and New Mexico through power purchase agreements.

well received by local leaders and environmental groups, and further our position as a clean energy leader.

The Right Mix doesn't work if you can't deliver on price. I am proud of our ability to transform our energy supply portfolio, protect the environment through clean energy sources and state-of-the-art emissions controls and invest significantly in our communities through jobs, tax base and economic development—all at a competitive price.

Improve utility performance

Our assets are long lived and best optimized via a long runway. A key objective is to establish longer-term regulatory agreements to support just that, positioning us to continue to close the gap between our earned and allowed returns while creating greater price certainty for customers. In 2015, we achieved a 9.07 percent (weather adjusted) ongoing return on equity (ROE) for our regulated businesses, consistent with our goal of closing the ROE gap.

Through legislation and regulatory filings, we made significant progress in securing longer-term frameworks. In particular, we reached a settlement on a three-year plan in our Colorado electric case, which had strong stakeholder support and demonstrates the shared benefits of such plans. We also supported the enactment of new legislation in Minnesota and Texas that provides the foundation for more timely and holistic recovery of costs in those states. We filed a thoughtful, multi-year electric plan in Minnesota consistent with that legislation. In December, the Minnesota commission approved our 2016 interim rate request of approximately \$164 million, subject to refund, and will review the plan in 2016. And our Wisconsin operating company successfully completed a combined gas and electric case that will bring added stability to our revenues over time with the first fixed charge increase since 2006.

Our 2015 results demonstrate that we have a solid plan and effective execution. We will continue to work with stakeholders to create sound regulatory frameworks that meet our states' policy objectives and allow us to implement the right energy mix for the future.

Achieve operational excellence

Historically, we have done an excellent job of managing our operations and maintenance (O&M) expenses to deliver increased shareholder value. In 2015, we decreased our O&M expenses by 0.2 percent, as compared to 2014, without impacting service levels to our customers.

We are also investing in technology to improve the function and efficiency of our business systems. An example is the

successful launch of a new general ledger at the close of 2015. This and additional system upgrades scheduled for the next two years are key tools that will lead to increased productivity and streamlined operations.

Employee and public safety is an important part of The Right Mix needed to achieve operational excellence. It is an Xcel Energy priority that every employee goes home safe each night. I am pleased that we achieved the eighth consecutive year of improved employee safety results, with a reduction in both injury count and severity. According to our annual engagement survey, 94 percent of our employees indicate that their work area is a safe place and 91 percent indicate that safety rules are carefully observed, even if it means that work is slowed down.

We continue to cultivate a culture of safety to protect the public—a responsibility we take very seriously. We have replaced all known cast iron natural gas distribution lines, initiated a project to move meters to the outside of older homes and installed additional safety measures to better protect above-ground natural gas equipment from potential damage by vehicles.

Our electrical system delivers reliable service more than 99 percent of the time on average, and prompt service restoration is a hallmark of our business. When severe storms in Texas and New Mexico disrupted power in December, our dedicated employees once again delivered, safely restoring power to 84 percent of customers within 12 hours and 98 percent of customers within 24 hours. We also received the Edison Electric Institute's Emergency Response Recovery Award for our work during a July storm in Minnesota that impacted 250,000 customers. We continue to make improvements in our customer communication, allowing customers to plan accordingly during service outages.

We also prepare for threats that we can't see. Last fall, more than 150 employees participated in the GridEx III, a two-day national drill coordinated by the North American Electric Reliability Corporation (NERC), to test the industry's preparedness for a national physical and cyber attack on the electric grid. This exercise provided a meaningful opportunity to evaluate our responsiveness and communications plans, and to strengthen our connection to government response agencies. We are investing in both assets and talent to make the energy grid even more robust, resilient and secure.

Expand customer options and solutions

Our customers want more ways to save energy and money, to connect with us in the ways convenient to them and exercise



BRECKENRIDGE BREWERY: A PERFECT BATCH OF ENERGY-EFFICIENT SOLUTIONS

When Breckenridge Brewery opened in 1990, it was the third craft brewery in Colorado. Twenty five years later, it has grown to produce more than 70,000 barrels of beer annually, distributed in 35 states. When its growth plans called for a new brewery to be built in Littleton, Colo., the leadership team partnered with our Energy Design Assistance (EDA) program to design a first class, energy-efficient facility.

During the design and construction phase, Xcel Energy collaborated with the brewery team, contractors and architects to develop and incent efficiency strategies ranging from choosing energy-efficient building materials, sensors and lighting fixtures throughout the facility to recapturing heat from the brewing process. This tailored solution encompassed both the building envelope and manufacturing process to ensure energy efficiency was achieved every step of the way.

The Breckenridge Brewery leadership team saw the value of these plans and invested in these solutions at the new facility that opened last summer. Those investments more than paid off. After an independent consultant verified the energy savings, Xcel Energy delivered an incentive check for \$59,470. Even more importantly, the brewery will save nearly \$51,000 in energy costs annually, recapturing its up-front investment in five years and freeing valuable capital to reinvest in the business.

"Who doesn't like to get a \$60,000 rebate check?" Breckenridge Brewery President Todd Usry asked. "Xcel Energy and the third party consultant were great to work with from the pre-construction phase all the way through."

In 2015, the EDA program rewarded Colorado and Minnesota customers with more than \$11.2 million in rebates for using energy-efficient design in 136 buildings.

A man with a mustache, wearing a red baseball cap and glasses, is working on a conveyor belt in a brewery. He is wearing a grey t-shirt with a red circular logo that says "BB". He is reaching out with his right hand to touch one of many dark glass beer bottles that are lined up on the conveyor belt. The bottles have red labels with the "BB" logo. The background shows more of the brewery's machinery and conveyor belts with more bottles. The lighting is bright and industrial.

A Breckenridge Brewery employee conducts a quality control test at the company's new facility in Littleton, Colo. The brewery leadership team partnered with Xcel Energy on numerous energy conservation strategies.

THE RIGHT MIX



Jeff Reali of the Hudson Service Center installs an LED fixture in an Xcel Energy-owned streetlight near the St. Croix River in Hudson, Wisc.



Mary Jo Woolf (left), director, Distribution Customer Operations; Brian Elwood (right), manager, Community Relations; and Tom Zeuil, director of Public Works and Parks for the City of Hudson, Wisc., all played important roles in the Hudson LED street lighting project.

A WELL-LIT PATH TO EFFICIENCY

Our communities are interested in saving money and reducing their environmental footprint, and our programs deliver. Case in point: Xcel Energy recently launched a five-year project to upgrade nearly 300,000 streetlights with new, energy-efficient LED fixtures that use 40 to 60 percent less energy than conventional lighting. Our communities will not only see a decrease in their electric bills, they will see fewer replacements, less required maintenance and higher quality lighting.

We upgraded approximately 50 communities in Wisconsin in the fall of 2015 and have plans to roll out the program across our service territory, subject to regulatory approval.

options in areas like renewable energy and home energy management, and we delivered in 2015. Ranked in the top 5 nationally, Xcel Energy's energy-efficiency programs saved customers enough electricity to power 115,000 homes and enough natural gas to serve 17,000 homes.

For customers wanting more renewable energy options, we are building on our Windsorce® program with new solar options in Colorado, Minnesota and Wisconsin. We continue to improve our digital experience to increase customer satisfaction and loyalty. We have also enhanced My Account, along with proactive outage and billing notifications that are driving increased customer engagement.

Anticipating and exceeding customer expectations is critical to our ongoing success, and we are putting our technology expertise to work to do just that. Innovative pilot programs like smart thermostats, connected home programs and a unique partnership with Panasonic to test and deliver new energy solutions are just some of the ways we are providing customers with tools to manage their energy use and costs while increasing comfort.

In 2015, 95 percent of our surveyed customers gave us high marks for overall satisfaction, but we are not resting on those laurels—we are working to enhance the overall customer experience to increase customer satisfaction and loyalty even more.

Invest for the future

The \$15 billion of base capital investments we will make during the next five years will grow our rate base by 3.7 percent annually while strengthening the grid and transitioning to a cleaner energy supply mix. The Right Mix of investments includes power generation, the electrical grid, pipelines and transmission and distribution infrastructure to deliver gas and electricity to our customers. We have identified an additional \$2.5 billion of upside investment opportunity that, if achieved, would drive rate base growth of 5.5 percent.

Through a "steel for fuel" strategy, our investments create both customer and shareholder value as we invest in wind energy to offset fossil fuel costs. The purchases of the Border Wind Farm in North Dakota and the Pleasant Valley Wind Farm in Minnesota, coupled with construction of the Courtenay Wind Farm in North Dakota, provide growing opportunities to increase our wind generation ownership.

Transmission remains a growth opportunity for us. Our three independent transmission companies made steady progress in 2015, winning several key regulatory approvals, building

new competitive bidding capabilities and streamlining key processes, which will lead to more accurate project estimates in 2016 and beyond. We also energized two major transmission lines in Minnesota as part of the multi-year CapX2020 project to help bring our growing portfolio of renewable energy to the marketplace.

Developments in 2015 set the stage for future growth of our natural gas business, which is expected to increase as carbon policy takes hold. The passage of key legislation in Minnesota supports our ability to “gas up” smaller communities previously served only by propane. We also won the right—in true competitive fashion—to build a pipeline to serve a coal-to-natural gas generation conversion and will continue to look for opportunities to move upstream in natural gas delivery.

Employees make it happen

Our 12,000+ employees are the cornerstone of our business and the driving force behind our success. As many of our long-tenured employees approach retirement, our nationally recognized veteran hiring initiatives and outreach programs with universities, trade schools and community organizations are helping us manage a significant workforce transition so that we continue to have The Right Mix of skills and experience to ensure future success.

The Right Mix

Balance. Performance. Results. People. We have our eye on The Right Mix in all that we do.

As we look ahead, rest assured we will take a leading role in delivering for our customers and communities, collaborating with stakeholders and building value for you. Our performance over time, our ability to reach new milestones and our understanding of a changing marketplace demonstrate that Xcel Energy is well positioned for long-term success.

Thank you for the trust you place in Xcel Energy. We know you have options for your investment dollars, and we are keenly focused to deliver the value proposition you have come to know and expect. We look forward to another outstanding year in 2016.

Sincerely,



Ben Fowke
Chairman, President and Chief Executive Officer



In 2015, Xcel Energy made significant infrastructure investments to power homes and businesses in southeastern New Mexico, one of the fastest-growing areas of the state.

NEW MEXICO: SUPPORTING GROWTH THROUGH INFRASTRUCTURE INVESTMENTS

If your picture of southeastern New Mexico is a vast, open landscape, think again—it is now one of the fastest-growing sections of the state. Major developments include new oil and natural gas extraction facilities, as well as expanded potash mining and commercial and residential development. To meet the rapidly increasing needs of the energy-rich areas of our service territory, Xcel Energy is investing hundreds of millions of dollars in the energy grid to provide reliable and affordable power to help drive the New Mexico economy.

To meet the time-sensitive nature of our customers’ needs—many of whom were burning diesel engines to fuel their operations—we executed a plan to build new transmission and distribution infrastructure to deliver electricity to the area. During the process, we boosted the local economy by hiring local contractors and businesses to assist in building seven substations as more than 250 miles of transmission and distribution lines were energized in 2015 in Lea and Eddy counties. Another substation near Dora connected the large Roosevelt wind farm to the grid.

Xcel Energy is one of the fastest-growing, investor-owned transmission systems with more than 20,000 miles of lines and 1,200 substations. In 2015, we energized 16 new substations, upgraded 27 existing substations and placed more than 700 miles of new lines into service—with our average cost per mile for new transmission below the national average.

Ross White, a third-year lineman apprentice and military veteran who joined Xcel Energy after serving six years with the U.S. Marine Corps, installs a conductor damper on a transmission line near Carlsbad, N.M.



THE RIGHT MIX

The Black Dog Generating Station in Burnsville, Minn., is transitioning to a natural gas facility, part of Xcel Energy's plan to significantly reduce carbon dioxide emissions. In Colorado, we also retired a coal unit at the Cherokee Generating Station and completed construction of a new combined-cycle natural gas plant—two significant milestones in our Clean Air-Clean Jobs project.



Tony Wendland (left), a gas project manager, visits with Jake Gundry, Black Dog Generating Station manager, about Xcel Energy's successful bid to supply a natural gas pipeline to the facility.

LAST TRAIN TO BLACK DOG: SUNSETTING COAL OPERATIONS

More than six decades after the Black Dog Generating Station began providing electricity to residents in the Twin Cities, the last coal train—125 cars long—coasted to a stop in April at the Burnsville, Minn., facility, carrying 12,500 tons of coal.

That final shipment marked the end of an era at Black Dog that began with coal first supplied by river barges before transitioning to rail cars in the 1980s. Those train tracks have been removed, along with the coal yard and other remnants of how most of the country's power was produced in the 20th century.

Black Dog's transition away from coal began in 2002 when two coal units were converted to natural gas. Preparation for a new combustion turbine gas unit at the site is now underway and is expected to be operational by early 2018. The retiring and repowering of aging coal-fired units is part of Xcel Energy's plan to significantly reduce carbon emissions 60 percent in the Upper Midwest (compared to 2005 levels) by 2030.

This project will provide The Right Mix of advanced technology, cost-effective energy and significant environmental benefits. When complete, an expansive green space will replace the former coal yard and will blend naturally with the 1,250 acres surrounding the plant that Xcel Energy leases to the United States Fish and Wildlife Service for \$1 each year.

In Colorado, we also achieved a significant milestone in our Clean Air-Clean Jobs project in 2015 by retiring the third coal unit at our Cherokee Generating Station and bringing online the new combined-cycle units at the plant—the entire \$1 billion project remains on schedule and within budget.

So far, under the project, we have retired five coal units (518 megawatts of coal), and we expect to reduce nitrogen oxides by 86 percent, sulfur dioxide emissions by 83 percent and mercury emissions by 82 percent when the project is complete in 2017. The project will contribute to a projected 35 percent reduction in carbon dioxide emissions (from 2005 levels) by 2020 in Colorado.

GIVING BACK TO THE COMMUNITIES WE SERVE

Our business will only be as successful as the communities we serve, and being supportive and connected community partners is one of our core values. Our 5th annual Day of Service positively impacted 80 non-profit organizations in our service territory; 3,500 employees, retirees and their families donated 10,000 hours of volunteer time in a single day.

In 2015, we awarded \$3.8 million in Foundation grants to more than 400 non-profit organizations across our service territory, with a continued focus on science, technology, engineering and math (STEM) education, economic sustainability, environmental stewardship and accessibility to the arts. Our employees donated 50,000 volunteer hours to local non-profit organizations.

We also achieved record-breaking United Way results this past year, with employees and retirees donating \$2.8 million in pledges. This is the highest combined total in our campaign history and, when added to the corporate match, will result in nearly \$5.3 million in donated funds for our communities.

We also care for our communities in unique ways. Our award-winning Clean Energy Partnership with the City of Minneapolis and CenterPoint Energy laid the foundation for future energy efficiency, renewable energy and carbon reduction goals.



Xcel Energy volunteers Brandon Hassan, Alex Hassan, Roger Ly and Robert Hendricks (foreground to background) apply a fresh coat of paint during Xcel Energy's 5th annual Day of Service at AccessAbility, a Minneapolis non-profit that provides opportunities for self-sufficiency for people with barriers to employment and community inclusion.

HIRING THE VERY BEST

Xcel Energy continues to be recognized for its leadership in veteran hiring. With 9 percent of our workforce comprised of veterans and for exceeding our 10 percent annual veteran hiring goal in 2015, Monster/Military.com ranked Xcel Energy as No. 8 in their Best Companies for Veterans list. *Military Times* named us one of the country's top places for veterans to work for the second year in a row. Ben Fowke was also honored with the Responsible CEO of the Year award from *Corporate Responsibility* magazine for our efforts to recruit and retain military veterans.



Mario Gradillas joined Xcel Energy on October 14, 2013, after serving a four-year active enlistment in the United States Air Force. Mario spent most of his time working as a crew chief at Little Rock Air Force Base.

At Xcel Energy, Gradillas is a compliance training consultant to help ensure we have a qualified and trained workforce.



We reached 190 megawatts of large-scale solar capacity on our system in 2015 from solar farms in several states, including the Greater Sandhill solar farm in southwestern Colorado.

HARVESTING THE SUN IN MORE WAYS THAN ONE

Large-scale solar projects currently provide energy at about half the cost of rooftop solar panels and can produce 50 percent more energy, panel-for-panel. These systems benefit from their scale and are located in areas that maximize sun exposure. Sun tracking and other technology enhancements help to maximize their generating capacity.

Xcel Energy purchases solar energy under long-term agreements with project owners. At the end of 2015, we reached approximately 190 megawatts of large-scale solar on our systems—enough to power 53,000 average-size homes for a year. In 2016, we will add nearly three times this solar capacity as seven new, large-scale projects begin producing power in locations throughout our service territory.

Smaller community solar gardens are also sprouting up across the states we serve. In 2015, Vetter Farms in southern Minnesota partnered with Minnesota-based Novel Energy Solutions to bring online the first community solar garden in Minnesota under Xcel Energy's Solar*Rewards® Community® program.

The program allows developers to connect solar arrays to Xcel Energy's electric distribution system and participating subscribers to receive a credit on their Xcel Energy bill. The program is designed to provide a new option for Xcel Energy's Minnesota customers who want to participate directly in a solar energy program but cannot or do not want to install their own solar panels. It allows neighboring residents, nonprofits, churches and businesses to share access to solar energy.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2015
or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number: 001-3034

Xcel Energy Inc.

(Exact name of registrant as specified in its charter)

Minnesota

(State or other jurisdiction of incorporation or organization)

41-0448030

(I.R.S. Employer Identification No.)

414 Nicollet Mall

Minneapolis, MN 55401

(Address of principal executive offices)

Registrant's telephone number, including area code: **612-330-5500**

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

<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
Common Stock, \$2.50 par value per share	New York Stock Exchange
Securities registered pursuant to section 12(g) of the Act: None	

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☒ Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. ☒ Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer (Do not check if a smaller reporting company) ☐ Smaller Reporting Company

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

As of June 30, 2015, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was \$16,313,953,331 and there were 506,959,395 shares of common stock outstanding.

As of February 15, 2016, there were 507,553,673 shares of common stock outstanding, \$2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's Definitive Proxy Statement for its 2016 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1 — Business

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)

Eloigne	Eloigne Company
NCE	New Century Energies, Inc.
NMC	Nuclear Management Company, LLC
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin operated on an integrated basis and managed by NSP-Minnesota
NSP-Wisconsin.	Northern States Power Company, a Wisconsin corporation
Operating companies	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
PSCo	Public Service Company of Colorado
PSRI	P.S.R. Investments, Inc.
SPS	Southwestern Public Service Co.
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
WGI	WestGas InterState, Inc.
WYCO	WYCO Development LLC
Xcel Energy	Xcel Energy Inc. and its subsidiaries
XETD	Xcel Energy Transmission Development Company, LLC
XEST	Xcel Energy Southwest Transmission Company, LLC
XEWT	Xcel Energy West Transmission Company, LLC

Federal and State Regulatory Agencies

ASLB	Atomic Safety and Licensing Board
CFTC	Commodity Futures Trading Commission
CPUC	Colorado Public Utilities Commission
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DOC	Minnesota Department of Commerce
DOE	United States Department of Energy
DOI	United States Department of the Interior
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPCA	Minnesota Pollution Control Agency
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
NRC	Nuclear Regulatory Commission
PNM	Public Service Company of New Mexico
PSCW	Public Service Commission of Wisconsin
PUCT	Public Utility Commission of Texas
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission

Electric, Purchased Gas and Resource Adjustment Clauses

CIP	Conservation improvement program
DCRF	Distribution cost recovery factor
DSM	Demand side management
DSMCA	Demand side management cost adjustment
ECA	Retail electric commodity adjustment
EE	Energy efficiency
EECRF	Energy efficiency cost recovery factor
EIR	Environmental improvement rider (recovers the costs associated with investments in environmental improvements to fossil fuel generation plants)
EPU	Extended power uprate
ERP	Electric resource plan
FCA	Fuel clause adjustment
FPPCAC	Fuel and purchased power cost adjustment clause
GCA	Gas cost adjustment
GUIC	Gas utility infrastructure cost rider
PCCA	Purchased capacity cost adjustment
PCRF	Power cost recovery factor (recovers the costs of certain purchased power costs)
PGA	Purchased gas adjustment
PSIA	Pipeline system integrity adjustment
QSP	Quality of service plan
RDF	Renewable development fund
RER	Renewable energy rider
RES	Renewable energy standard (recovers the costs of new renewable generation)
RESA	Renewable energy standard adjustment
SCA	Steam cost adjustment
SEP	State energy policy
TCA	Transmission cost adjustment
TCR	Transmission cost recovery adjustment
TCRF	Transmission cost recovery factor (recovers transmission infrastructure improvement costs and changes in wholesale transmission charges)

Other Terms and Abbreviations

AFUDC	Allowance for funds used during construction
ATM	At-the-market
ALJ	Administrative law judge
APBO	Accumulated postretirement benefit obligation
ARO	Asset retirement obligation
ASU	FASB Accounting Standards Update
BART	Best available retrofit technology
C&I	Commercial and Industrial
CAA	Clean Air Act
CACJA	Clean Air Clean Jobs Act
CAIR	Clean Air Interstate Rule
CapX2020	Alliance of electric cooperatives, municipalities and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CCN	Certificate of convenience and necessity
CIG	Colorado Interstate Gas Company, LLC
CO ₂	Carbon dioxide

CPCN	Certificate of public convenience and necessity
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction work in progress
EEI	Edison Electric Institute
EGU	Electric generating unit
EPS	Earnings per share
ERCOT	Electric Reliability Council of Texas
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FIP	Federal implementation plan
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
HTY	Historic test year
IM	Integrated market
ISFSI	Independent Spent Fuel Storage Installation
ITC	Investment Tax Credit
LCM	Life cycle management
LLW	Low-level radioactive waste
LNG	Liquefied natural gas
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Moody's	Moody's Investor Services
MYP	Multi-year plan
NAAQS	National Ambient Air Quality Standard
Native load	Customer demand of retail and wholesale customers that a utility has an obligation to serve under statute or long-term contract
NOL	Net operating loss
NOx	Nitrogen oxide
NOV	Notice of violation
NTC	Notifications to construct
NYISO	New York Independent System Operator
O&M	Operating and maintenance
OCC	Office of Consumer Counsel
OCI	Other comprehensive income
PCB	Polychlorinated biphenyl
PFS	Private Fuel Storage, LLC
PI	Prairie Island nuclear generating plant
PJM	PJM Interconnection, LLC
PM	Particulate matter
PPA	Purchased power agreement
PRP	Potentially responsible party
PTC	Production tax credit
PV	Photovoltaic
QF	Qualifying facilities
R&E	Research and experimentation
REC	Renewable energy credit
RFP	Request for proposal
ROE	Return on equity

RPS.....	Renewable portfolio standards
RTO	Regional Transmission Organization
Sharyland	Sharyland Distribution and Transmission Services, LLC
SIP	State implementation plan
SO ₂	Sulfur dioxide
SPP.....	Southwest Power Pool, Inc.
S&P	Standard & Poor's Ratings Services
TO.....	Transmission owner
TransCo	Transmission-only subsidiary
TSR.....	Total shareholder return
Wexpro.....	Wexpro Development Company

Measurements

Bcf	Billion cubic feet
GWh.....	Gigawatt hours
KV	Kilovolts
KWh.....	Kilowatt hours
Mcf.....	Thousand cubic feet
MMBtu	Million British thermal units
MW.....	Megawatts
MWh.....	Megawatt hours

COMPANY OVERVIEW

Xcel Energy Inc. is a holding company with subsidiaries engaged primarily in the utility business. In 2015, Xcel Energy Inc.'s continuing operations included the activity of four wholly owned utility subsidiaries that serve electric and natural gas customers in eight states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, and serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with WYCO, a joint venture formed with CIG to develop and lease natural gas pipelines, storage, and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the regulated utility operations.

Xcel Energy Inc. was incorporated under the laws of Minnesota in 1909. Xcel Energy's executive offices are located at 414 Nicollet Mall, Minneapolis, Minn. 55401. Its website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC. The public may read and copy any materials that Xcel Energy files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at <http://www.sec.gov>.

Xcel Energy's corporate strategy focuses on four core objectives: improving utility performance; driving operational excellence; improving customer experience; and investing for the future. These core objectives are designed to provide an attractive total return to our investors, including long-term annual ongoing EPS growth of four to six percent and annual dividend increases of five to seven percent.

NSP-Minnesota

NSP-Minnesota is a utility primarily engaged in the generation, purchase, transmission, distribution and sale of electricity in Minnesota, North Dakota and South Dakota. The wholesale customers served by NSP-Minnesota comprised approximately eight percent of its total KWh sold in 2015. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota. NSP-Minnesota provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 0.5 million customers. Approximately 88 percent of NSP-Minnesota's retail electric operating revenues were derived from operations in Minnesota during 2015. Although NSP-Minnesota's large C&I electric retail customers are comprised of many diversified industries, a significant portion of NSP-Minnesota's large C&I electric sales include the following industries: petroleum, coal and food products. For small C&I customers, significant electric retail sales include the following industries: real estate and educational services. Generally, NSP-Minnesota's earnings contribute approximately 35 percent to 45 percent of Xcel Energy's consolidated net income.

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC-approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System.

NSP-Minnesota owns the following direct subsidiary: United Power and Land Company, which holds real estate.

NSP-Wisconsin

NSP-Wisconsin is a utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of northwestern Wisconsin and in the western portion of the Upper Peninsula of Michigan. NSP-Wisconsin purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in this service territory. NSP-Wisconsin provides electric utility service to approximately 256,000 customers and natural gas utility service to approximately 112,000 customers. Approximately 98 percent of NSP-Wisconsin's retail electric operating revenues were derived from operations in Wisconsin during 2015. Although NSP-Wisconsin's large C&I electric retail customers are comprised of many diversified industries, a significant portion of NSP-Wisconsin's large C&I electric sales include the following industries: food products, paper, allied products and sand mining for oil and gas extraction. For small C&I customers, significant electric retail sales include the following industries: grocery and dining establishments, educational services and health services. Generally, NSP-Wisconsin's earnings contribute approximately five percent to 10 percent of Xcel Energy's consolidated net income.

The management of the electric production and transmission system of NSP-Wisconsin is integrated with NSP-Minnesota.

NSP-Wisconsin owns the following direct subsidiaries: Chippewa and Flambeau Improvement Co., which operates hydro reservoirs; Clearwater Investments Inc., which owns interests in affordable housing; and NSP Lands, Inc., which holds real estate.

PSCo

PSCo is a utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in Colorado. The wholesale customers served by PSCo comprised approximately 11 percent of its total KWh sold in 2015. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas. PSCo provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 1.4 million customers. All of PSCo's retail electric operating revenues were derived from operations in Colorado during 2015. Although PSCo's large C&I electric retail customers are comprised of many diversified industries, a significant portion of PSCo's large C&I electric sales include the following industries: fabricated metal products, communications and business services. For small C&I customers, significant electric retail sales include the following industries: real estate and dining establishments. Generally, PSCo's earnings contribute approximately 40 percent to 50 percent of Xcel Energy's consolidated net income.

PSCo owns the following direct subsidiaries: 1480 Welton, Inc. and United Water Company, both of which own certain real estate interests; and Green and Clear Lakes Company, which owns water rights and certain real estate interests. PSCo also holds a controlling interest in several other relatively small ditch and water companies.

SPS

SPS is a utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of Texas and New Mexico. The wholesale customers served by SPS comprised approximately 31 percent of its total KWh sold in 2015. SPS provides electric utility service to approximately 389,000 retail customers in Texas and New Mexico. Approximately 71 percent of SPS' retail electric operating revenues were derived from operations in Texas during 2015. Although SPS' large C&I electric retail customers are comprised of many diversified industries, a significant portion of SPS' large C&I electric sales include the following industries: oil and gas extraction, as well as petroleum and coal products. For small C&I customers, significant electric retail sales include the following industries: oil and gas extraction, grocery and dining establishments. Generally, SPS' earnings contribute approximately 10 percent to 15 percent of Xcel Energy's consolidated net income.

Other Subsidiaries

WGI is a small interstate natural gas pipeline company engaged in transporting natural gas from the PSCo system near Chalk Bluffs, Colo., to Cheyenne, Wyo.

WYCO was formed as a joint venture with CIG to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy has a 50 percent ownership interest in WYCO. The gas pipeline and storage facilities are leased under a FERC-approved agreement to CIG.

Xcel Energy Services Inc. is the service company for Xcel Energy Inc.

XETD and XEST are transmission-only subsidiaries that will, respectively, participate in MISO and SPP competitive bidding processes for transmission projects. XEWT is a transmission-only subsidiary formed to competitively bid on transmission projects in the western United States.

Xcel Energy Inc.'s nonregulated subsidiary is Eloigne, which invests in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy conducts its utility business in the following reportable segments: regulated electric utility, regulated natural gas utility and all other. See Note 17 to the consolidated financial statements for further discussion relating to comparative segment revenues, income from operations and related financial information.

ELECTRIC UTILITY OPERATIONS

NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC, the NDPSC and the SDPUC within their respective states. The MPUC also has regulatory authority over security issuances, property transfers, mergers, dispositions of assets and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's ERPs for meeting customers' future energy needs. The MPUC also certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV that will be located within the state. No large power plant or transmission line may be constructed in Minnesota except on a site or route designated by the MPUC. The NDPSC and SDPUC have regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota and South Dakota, respectively.

NSP-Minnesota is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transfers and mergers, and natural gas transactions in interstate commerce. As approved by the FERC, NSP-Minnesota operates within the MISO RTO and MISO wholesale market. NSP-Minnesota is authorized to make wholesale electric sales at market-based prices. NSP-Minnesota is a transmission owning member of the MISO RTO.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms — NSP-Minnesota has several retail adjustment clauses that recover fuel, purchased energy and other resource costs:

- *CIP* — The CIP recovers the costs of conservation and demand-side management programs that help customers save energy.
- *EIR* — The EIR recovers the costs of environmental improvement projects.
- *RDF* — The RDF allocates money collected from retail customers to support the research and development of emerging renewable energy projects and technologies.
- *RES* — The RES recovers the cost of new renewable generation in Minnesota.
- *RER* — The RER recovers the cost of new renewable generation in North Dakota.
- *SEP* — The SEP recovers costs related to various energy policies approved by the Minnesota legislature.
- *TCR* — The TCR recovers costs associated with new investments in electric transmission and distribution costs that facilitate grid modernization.
- *Infrastructure* — The Infrastructure rider recovers costs associated with specific investments in generation and incremental property taxes in South Dakota.

NSP-Minnesota's retail electric rates in Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments for changes in prudently incurred costs of fuel, fuel related items and purchased energy. NSP-Minnesota is permitted to recover these costs through FCA mechanisms approved by the regulators in each jurisdiction. In general, capacity costs are not recovered through the FCA. In addition, costs associated with MISO are generally recovered through either the FCA or base rates.

Minnesota state law requires NSP-Minnesota to invest two percent of its state electric revenues and half a percent of its state gas revenues in CIP. NSP-Minnesota was in compliance with this standard in 2015 and expects to be in compliance in 2016. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures. Minnesota state law also requires NSP-Minnesota to submit a CIP plan at least every three years.

CIP Triennial Plan — In 2012, the DOC approved NSP-Minnesota's 2013 through 2015 CIP Triennial Plan, which increases the energy savings goals and budgets over the previous plan. The plan sets an annual energy savings goal for electric of saving the equivalent of 1.5 percent the volume of electric energy sales (calculated on a historical three-year average, excluding opt-out customers) and an annual natural gas goal of saving 1.0 percent the volume of gas energy sales. During 2015, NSP-Minnesota submitted an extension to the triennial plan for 2016 which was approved by the DOC. NSP-Minnesota anticipates submitting a 2017 through 2019 plan during the first half of 2016.

Capacity and Demand

Uninterrupted system peak demand for the NSP System's electric utility for each of the last three years and the forecast for 2016, assuming normal weather conditions, is as follows:

	System Peak Demand (in MW)			
	2013	2014	2015	2016 Forecast
NSP System	9,524	8,848	8,621	9,327

The peak demand for the NSP System typically occurs in the summer. The 2015 system peak demand for the NSP System occurred on Aug. 14, 2015. The 2015 system peak demand was lower due to cooler summer weather. The 2016 forecast assumes normal peak day weather.

Energy Sources and Related Transmission Initiatives

NSP-Minnesota expects to use existing power plants, power purchases, CIP options, new generation facilities and expansion of existing power plants to meet its system capacity requirements.

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and independent power producers. Generally, long-term dispatchable purchased power contracts typically require a periodic payment to secure the capacity and a charge for the delivered associated energy. Long-term energy-only purchased power contracts contain a charge for the purchased energy. NSP-Minnesota also makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations, or to obtain energy at a lower cost.

Purchased Transmission Services — NSP-Minnesota and NSP-Wisconsin have contracts with MISO and other regional transmission service providers to deliver power and energy to their customers.

Courtenay Wind Farm — In September 2015, NSP-Minnesota began construction of the Courtenay wind farm, a 200 MW NSP-Minnesota owned project in North Dakota. In July and August 2015, the MPUC and NDPSC, respectively, approved the Courtenay wind farm with recovery up to \$300 million of capital costs. The project costs were included in the Minnesota RES rider and the North Dakota RER.

NSP System Resource Plans — In January 2015, NSP-Minnesota filed its 2016-2030 Integrated Resource Plan (the Plan) with the MPUC.

In October 2015, NSP-Minnesota proposed revisions to the Plan. The revised proposal addressed stakeholder recommendations as well as the final Clean Power Plan (CPP) issued by the EPA. The revised Plan is based on four primary elements: (1) accelerate the transition from coal energy to renewables, (2) preserve regional system reliability, (3) pursue energy efficiency gains and grid modernization, and (4) ensure customer benefits. The provisions included in the Plan would allow for a 60 percent reduction in carbon emissions from 2005 levels by 2030 and is expected to result in 63 percent of NSP System energy being carbon-free by 2030. Specific terms of the proposal include:

- The addition of 800 MW of wind and 400 MW of utility scale solar to the pre-2020 time-frame;
- The addition of 1000 MW of wind and 1000 MW of utility scale solar between 2020-2030;
- The retirement of Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026;
- The addition of a 230 MW natural gas combustion turbine in North Dakota by 2025;
- Replacement of Sherco coal generation with a 786 MW natural gas combined cycle unit at the Sherco site no later than 2026; and
- Operation of the Monticello and PI nuclear plants through their current license periods in the early 2030's.

NSP-Minnesota believes this will provide substantial opportunities for the ownership of renewable generation and replacement thermal generation. In January 2016, NSP-Minnesota filed supplemental economic and technical information in support of its revised Plan, demonstrating anticipated compliance with the CPP while maintaining reasonable costs for customers. Additionally, NSP-Minnesota responded to MPUC inquiries regarding forecasted cost increases at PI (through end of licensed life) and committed to provide additional information if the MPUC wishes to further explore alternatives to operating PI through its current licenses. While the procedural schedule has not yet been finalized, the current expectation is that the MPUC will make a decision in the second half of 2016.

North Dakota Energy Resource Considerations — In February 2014, the NDPSC approved a settlement agreement between NSP-Minnesota and NDPSC Advocacy Staff in resolution of the 2013 North Dakota electric rate case. Among other things, the settlement agreement included a commitment to develop a generation cost allocation mechanism for serving North Dakota customers in a way that reflects North Dakota energy policy. In September 2015, NSP-Minnesota and NDPSC Advocacy Staff satisfied this commitment through joint filing of a Negotiated Agreement with key terms including:

- Acceleration of NSP-Minnesota's commitment to locate thermal generation in North Dakota from 2036 to by the end of 2025;
- Exclusion of select wind and small solar PPAs from the NSP-Minnesota's North Dakota Fuel Cost Rider;
- Continued recovery in North Dakota of six existing biomass PPAs, subject, in part, to refund if NSP-Minnesota fails to achieve its generation commitment by the end of 2025;
- Extension of the current rate moratorium through 2017;

- NDPSC Staff support for continued use of 12-Coincident Peak system allocator through 2025; and,
- Development of a framework to address future generation resources to be filed with the NDPSC by Jan. 1, 2017.

The NDPSC conducted a work session in February 2016, to discuss their view of the Negotiated Agreement with their Advisory Staff. Next steps would include further NDPSC hearing(s) to continue discussion or take action on the Negotiated Agreement. No specific procedural schedule has been established for this matter.

NSP-Minnesota's Petition for an Advance Determination of Prudence — In February 2016, the NDPSC discussed NSP-Minnesota's Petition for an Advance Determination of Prudence (ADP) for 345 MW of capacity and associated energy to be added to the NSP System through a 20-year PPA with Mankato Energy Center, LLC, an affiliate of Calpine Corporation. While a certain commissioner indicated support for the opportunity to add larger, low-priced, dispatchable generation, other commissioners were concerned the resource would not be necessary by the 2019 expected in-service date and not supportive of the ADP. Commissioners are expected to vote on the matter on March 9, 2016. The North Dakota portion of the PPA is approximately \$1.2 million per year.

CapX2020 — The estimated cost of the five major CapX2020 transmission projects listed below is \$2 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately \$1.1 billion of the total investment. As of Dec. 31, 2015, Xcel Energy has invested \$1.0 billion of its \$1.1 billion share of the five CapX2020 transmission projects. The projects are as follows:

- Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. 161/345 Kilovolt (KV) transmission line — The Wisconsin portion of the project includes a new substation and approximately 50 miles of new 345 KV transmission line, at an estimated cost of \$211 million. The final 161 KV segment of the project went into service in January 2016, while the final 345 KV segment of the project is expected to go into service in the fall of 2016;
- Brookings County, S.D. to Hampton, Minn. 345 KV transmission line — The project was placed in service in March 2015;
- Bemidji, Minn. to Grand Rapids, Minn. 230 KV transmission line — The project was placed in service in September 2012;
- Monticello, Minn. to Fargo, N.D. 345 KV transmission line — In April 2015, the final portion of the project was placed in service; and
- Big Stone South to Brookings County, S.D. 345 KV transmission line — Construction on the line began in September 2015, with completion anticipated in 2017.

Minnesota Solar — Minnesota legislation requires 1.5 percent of a public utility's total electric retail sales to retail customers be generated using solar energy by 2020. Of the 1.5 percent, 10 percent must come from systems sized 20 kilowatts or less. NSP-Minnesota anticipates it will meet its compliance requirements through large and small scale solar additions.

NSP-Minnesota also offers customer solar programs: a solar production incentive program for rooftop solar, called Solar*Rewards®, and a community solar garden program that provides bill credits to participating subscribers, called Solar*Rewards® Community®. Additionally, the DOC offers the "Made in Minnesota" program, providing incentives for the installation of small solar systems that were manufactured in-state, which generates renewable energy credits for utilities including NSP-Minnesota.

In August 2015, the MPUC issued an order regarding the Solar*Rewards Community program, limiting the size of solar installations eligible to participate in the program to five MW or less through Sept. 25, 2015. Subsequently, projects must be one MW or less. In October 2015, the MPUC denied requests for reconsideration of the project size limitation. Sunrise Energy Ventures, a Solar*Rewards Community developer, has appealed this decision to the Minnesota Court of Appeals.

Minnesota Legislation — In June 2015, the Minnesota governor signed the Jobs and Energy bill into law. Several approved mechanisms may provide additional options and opportunities in future rate cases, including the duration of future MYPs and more certainty regarding recovery of costs and the impact to customers. This bill provides:

- Increased flexibility for utilities to submit a MYP of up to five years;
- The potential for full capital recovery for all proposed years;
- O&M cost recovery based on an index;
- Distribution costs that facilitate grid modernization are eligible for rider recovery;
- Natural gas extension costs for unserved areas can be socialized and are eligible for rider recovery;
- Recovery of plant closure costs, should the MPUC order early plant closure, such as in a resource plan; and
- Allows implementation of interim rates for the first and second years of the MYP.

Annual Automatic Adjustment (AAA) of Charges — In June 2013, the DOC proposed that the MPUC adopt a fuel clause incentive that would normalize FCA recovery using monthly patterns derived from averages of the prior three-year period, setting and fixing this level during a rate case with no adjustment between rate cases. NSP-Minnesota and other utilities opposed this proposal. The DOC proposal is pending MPUC action.

Additionally, the DOC has indicated it will review prudence of replacement power costs associated with the Sherco Unit 3 outage event within the 2013 AAA docket. The 2013 and 2012 AAA dockets remain pending.

In September 2015, the 2014 AAA was filed with the MPUC and also remains pending.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes which are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. LLW consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in a plant.

NRC Regulation — The NRC regulates the nuclear operations of NSP-Minnesota. Decisions by the NRC can significantly impact the operations of the nuclear generating plants.

The NRC imposed new requirements after events at the nuclear generating plant in Fukushima, Japan in 2011. In 2012, the NRC issued orders which included requirements for mitigation strategies for beyond-design-basis external events, requirements with regard to reliable spent fuel instrumentation and requirements with regard to reliable hardened containment vents, which are applicable to boiling water reactor containments at the Monticello plant. The NRC also requested additional information including requirements to perform walkdowns of seismic and flood protection, to evaluate seismic and flood hazards and to assess the emergency preparedness staffing and communications capabilities at each plant. Except with respect to the revised order described below, all units are on track to meet the required compliance dates and be fully compliant by December 2016.

In 2013, the NRC issued a revised order with regard to reliable hardened containment vents. Compliance with the revised order will be completed during refueling outages in 2017-2019.

NSP-Minnesota expects that complying with these external event requirements will cost approximately \$90 to \$100 million at the Monticello and PI plants over the period 2012 through 2018. The majority of these costs have been and are expected to be capital in nature. The costs associated with compliance have been and are expected to continue to be recoverable from customers through regulatory mechanisms and consequently NSP-Minnesota does not expect a material impact on its results of operations, financial position, or cash flows.

The NRC continues to review its requirements for mitigating the risks of external events on nuclear plants. NSP-Minnesota expects the costs associated with compliance will be recoverable from customers.

Nuclear Regulatory Performance — The NRC has a Reactor Oversight Process that classifies U.S. nuclear reactors into various categories (referred to as Columns, from 1 to 5). Issues are evaluated as either green, white, yellow, or red based on their safety significance, with green representing the least safety concern and red representing the most concern.

At Dec. 31, 2015, Monticello and PI Unit 1 were in Column 1 (licensee response) with all green performance indicators and no greater than green findings or violations. Plants in Column 1 are subject to only a pre-defined set of basic NRC inspections.

Based on a December 2015 shutdown, PI Unit 2 will be moved from Column 1 to Column 2 (regulatory response) due to an anticipated white performance indicator related to the level of unplanned rapid shutdowns of the nuclear reactor, of which only a certain level is allowed per year to remain at the green performance level. Plants in Column 2 are subject to special NRC inspections to review and validate that performance issues or inspection findings have been properly addressed. PI Unit 2 returned to service in late February 2016 after addressing the issues leading to shutdown and will be eligible to return to Column 1 once the performance indicator returns to green, subject to an NRC inspection to close the issue. Depending on the unit's operation in 2016, PI Unit 2 could return to green performance and Column 1 later in 2016.

Monticello Spent Fuel Storage - Dry Shielded Canisters — In the fall of 2013, NSP-Minnesota's Monticello nuclear generating plant conducted a spent fuel loading campaign which resulted in five storage canisters being loaded and placed in the ISFSI and a sixth one being loaded but remaining in the plant pending resolution of weld inspection issues. Successful pressure and leak testing has demonstrated the safety and integrity of all six canisters involved. In December 2013, the NRC initiated an investigation to determine whether two contractor technicians at Monticello deliberately failed to follow procedure in performing Non-Destructive Examinations (NDE) on the six spent fuel storage canisters (Dry Shielded Canisters #11-16) in accordance with procedural requirements and to determine whether the contractors falsified records when recording the NDE results. The investigation determined that the two NDE contractors deliberately violated NRC requirements. NSP-Minnesota has taken several actions to assure that compliance with the NRC's regulations and Monticello's storage license can be demonstrated. In October 2015, NSP-Minnesota and the NRC participated in an alternative dispute resolution (ADR) session on this matter.

In December 2015, the NRC issued a confirmatory order formally approving a settlement reached through the ADR process in which NSP-Minnesota agreed to a timeline for attaining compliance on all six canisters as well as additional training and communications. As a result, the NRC will not issue a notice of violation or impose a civil penalty to NSP-Minnesota for this matter, and will consider the terms of its order as an escalated enforcement action for a period of one year from its issued date. NSP-Minnesota has filed an exemption request with the NRC for the completion of the final canister #16, which is anticipated to be acted upon in 2016. Costs attributable to the six canisters achieving full regulatory compliance within five years, as agreed to in the settlement, are currently being evaluated. No public safety issues have been raised, or are believed to exist, related to handling of spent nuclear fuel at Monticello in regard to this matter.

LLW Disposal — LLW from NSP-Minnesota's Monticello and PI nuclear plants is currently disposed at the Clive facility located in Utah and Waste Control Specialists facility located in Texas. If off-site LLW disposal facilities become unavailable, NSP-Minnesota has storage capacity available on-site at PI and Monticello that would allow both plants to continue to operate until the end of their current licensed lives.

High-Level Radioactive Waste Disposal — The federal government has the responsibility to permanently dispose of domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility.

Nuclear Geologic Repository - Yucca Mountain Project

In 2002, the U.S. Congress designated Yucca Mountain, Nevada as the first deep geologic repository. In 2008, the DOE submitted an application to construct a deep geologic repository at this site to the NRC. In 2010, the DOE announced its intention to stop the Yucca Mountain project and requested the NRC approve the withdrawal of the application. In 2010, the ASLB issued a ruling that the DOE could not withdraw the Yucca Mountain application.

The DOE's decision and the resulting stoppage of the NRC's review has prompted multiple legal challenges, including the DOE's authority to stop the project and withdraw the application, the DOE's authority to continue to collect the nuclear waste fund fee and the NRC's authority to stop their review of the DOE's application.

In August 2013, the D.C. Court of Appeals ordered the NRC to complete their review of the DOE's application to construct the Yucca Mountain repository. In November 2013, the NRC complied by issuing an order to the NRC Staff to complete and publish a safety evaluation report on the proposed Yucca Mountain nuclear spent fuel and waste repository. The NRC Staff completed and published its Safety Evaluation Report in January 2015. The NRC also requested that the DOE prepare a supplemental environmental impact statement (EIS) so the NRC Staff can complete its review. A supplement to the DOE's EIS was published in August 2015.

In November 2013, the U.S. Court of Appeals ordered the DOE to suspend the collection of the nuclear waste fund fee from nuclear utilities and to recommend to Congress that the nuclear waste fund fee be set to zero. In January 2014, the DOE sent its court mandated proposal to adjust the current fee to zero, which Congress approved in May 2014.

At the time that the DOE decided to stop the Yucca Mountain project and withdraw the application, the U.S. Secretary of Energy convened a Blue Ribbon Commission to recommend alternatives to Yucca Mountain for disposal of used nuclear fuel. In January 2012, the Blue Ribbon Commission report was issued. In January 2013, the DOE provided its report to Congress relative to their plans to implement the Blue Ribbon Commission's recommendations including the required legislative changes and authorizations. The report also announced the Obama Administration's intent to make a pilot consolidated interim storage facility available in 2021, a larger consolidated interim storage facility available in 2025 and a deep geologic repository available in 2048.

Nuclear Spent Fuel Storage

NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and PI nuclear generating plants. As of Dec. 31, 2015, there were 40 casks loaded and stored at the PI plant and 15 canisters loaded and stored at the Monticello plant. An additional 24 casks for PI and 15 canisters for Monticello have been authorized by the State of Minnesota. This currently authorized storage capacity is sufficient to allow NSP-Minnesota to operate until the end of the operating licenses in 2030 for Monticello, 2033 for PI Unit 1, and 2034 for PI Unit 2. Authorizations for additional spent fuel storage capacity may be required at each site to support either continued operation or decommissioning if the federal government does not begin operation of a consolidated interim storage installation.

Nuclear Waste Disposal Litigation — In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages for the DOE's failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contracts between the United States and NSP-Minnesota. NSP-Minnesota sought contract damages in this lawsuit through 2004. In September 2007, the Court awarded NSP-Minnesota \$116.5 million in damages through 2004. In August 2007, NSP-Minnesota filed a second complaint; this lawsuit claimed damages for 2005 through 2008.

In July 2011, the United States and NSP-Minnesota executed a settlement agreement resolving both lawsuits, providing an initial \$100 million payment from the United States to NSP-Minnesota, and providing a method by which NSP-Minnesota can recover its spent fuel storage costs through 2013. In January 2014, the United States and NSP-Minnesota agreed to an extension to the settlement agreement which will allow recovery of spent fuel storage costs through 2016. The extension does not address costs for spent fuel storage after 2016; such costs could be the subject of future litigation. In November 2015, NSP-Minnesota received a settlement payment of \$13.1 million. NSP-Minnesota has received a total of \$227.8 million of settlement proceeds as of Dec. 31, 2015. Amounts received from the installments are being returned to customers through ratemaking proceedings as determined by the MPUC and other state regulators.

NRC Waste Confidence Decision (WCD) — In September 2014, the NRC published a Generic Environmental Impact Statement (GEIS) and revised WCD rule, now called the Continued Storage Rule (CSR) on the temporary on-site storage of spent nuclear fuel. The CSR assesses how long temporary on-site storage can remain safe and when facilities for the disposal of nuclear waste will become available. Issuance of the CSR now allows the NRC to proceed with final license decisions regarding the new and renewed plant and Independent Spent Fuel Storage Installation (ISFSI) operating licenses without the need to litigate contentions related to the continued storage of spent nuclear fuel on-site. This may facilitate potential future spent fuel licensing needs for NSP-Minnesota.

The CSR is currently being challenged before the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit) on the grounds that the environmental impact statement is inadequate to satisfy the National Environmental Policy Act. A decision by the D.C. Circuit is anticipated later in 2016.

PI ISFSI License Renewal — The current license to operate an ISFSI at PI expired in October 2013. The NRC granted a renewed license for the ISFSI at PI in December 2015. The new expiration date of the renewed license is Oct. 31, 2053.

See Note 14 to the consolidated financial statements for further discussion regarding nuclear related items.

Energy Source Statistics

	Year Ended Dec. 31					
	2015		2014		2013	
	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
NSP System						
Coal	15,961	35%	18,079	39%	15,844	36%
Nuclear	12,425	27	13,434	29	12,161	28
Natural Gas	6,689	15	3,402	7	5,550	13
Wind ^(a)	6,235	14	6,243	14	5,481	13
Hydroelectric	3,326	7	3,560	8	3,223	7
Other ^(b)	1,083	2	1,417	3	1,323	3
Total	45,719	100%	46,135	100%	43,582	100%
Owned generation	33,818	74%	33,641	73%	29,249	67%
Purchased generation	11,901	26	12,494	27	14,333	33
Total	45,719	100%	46,135	100%	43,582	100%

^(a) This category includes wind energy de-bundled from RECs and also includes Windsources® RECs. The NSP System uses RECs to meet or exceed state resource requirements and may sell surplus RECs.

^(b) Includes energy from other sources, including solar, biomass, oil and refuse. Distributed generation from the Solar*Rewards program is not included, and was approximately eight, seven, and eight million net KWh for 2015, 2014, and 2013, respectively.

Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for owned electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels.

NSP System Generating Plants	Coal ^(a)		Nuclear		Natural Gas		Weighted Average Owned Fuel Cost
	Cost	Percent	Cost	Percent	Cost	Percent	
2015	\$ 2.15	47%	\$ 0.83	40%	\$ 3.89	13%	\$ 1.85
2014	2.23	52	0.89	42	6.27	6	1.94
2013	2.20	49	0.95	40	5.08	11	2.03

^(a) Includes refuse-derived fuel and wood.

The cost of natural gas in 2015 decreased due to lower wholesale commodity prices.

See Items 1A and 7 for further discussion of fuel supply and costs.

Fuel Sources

Coal — The NSP System normally maintains approximately 41 days of coal inventory. Coal supply inventories at Dec. 31, 2015 and 2014 were approximately 67 and 27 days usage, respectively. At Dec. 31, 2015, milder weather, purchase commitments and resolution of railcar congestion resulted in coal inventories being above optimal levels. NSP-Minnesota's generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Wyoming and Montana. During 2015 and 2014, coal requirements for the NSP System's major coal-fired generating plants were approximately 8.3 million tons and 9.3 million tons, respectively. Coal requirements for 2015 were lower due to the retirement of Black Dog Units 3 and 4 and relatively low natural gas prices. The estimated coal requirements for 2016 are approximately 7.9 million tons.

NSP-Minnesota and NSP-Wisconsin have contracted for coal supplies to provide 90 percent of their estimated coal requirements in 2016, and a declining percentage of the requirements in subsequent years. The NSP System's general coal purchasing objective is to contract for approximately 90 percent of requirements for the first year, 60 percent of requirements in year two, and 30 percent of requirements in year three. Remaining requirements will be filled through the procurement process or over-the-counter transactions.

NSP-Minnesota and NSP-Wisconsin have a number of coal transportation contracts that provide for delivery of 100 percent of their coal requirements in 2016 and 2017. Coal delivery may be subject to interruptions or reductions due to operation of the mines, transportation problems, weather and availability of equipment.

Nuclear — NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication to operate its nuclear plants. The contract strategy involves a portfolio of spot purchases and medium and long-term contracts for uranium concentrates, conversion services and enrichment services with multiple producers and with a focus on diversification to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

- Current nuclear fuel supply contracts cover 100 percent of uranium concentrates requirements through 2018 and approximately 59 percent of the requirements for 2019 through 2030;
- Current contracts for conversion services cover 100 percent of the requirements through 2021 and approximately 54 percent of the requirements for 2022 through 2030; and
- Current enrichment service contracts cover 100 percent of the requirements through 2026 and approximately 34 percent of the requirements for 2027 through 2030.

Fabrication services for Monticello and PI are 100 percent committed through 2030 and 2019, respectively.

NSP-Minnesota expects sufficient uranium concentrates, conversion services and enrichment services to be available for the total fuel requirements of its nuclear generating plants. Some exposure to market price volatility will remain due to index-based pricing structures contained in certain supply contracts.

Natural gas — The NSP System uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas supplies, transportation and storage services for power plants are procured under contracts to provide an adequate supply of fuel. However, as natural gas primarily serves intermediate and peak demand, remaining forecasted requirements are able to be procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to various natural gas indices. Most transportation contract pricing is based on FERC approved transportation tariff rates. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2015 and 2014, the NSP System did not have any commitments related to gas supply contracts; however commitments related to gas transportation and storage contracts were approximately \$310 million and \$349 million, respectively. Commitments related to gas transportation and storage contracts expire in various years from 2016 to 2028.

The NSP System also has limited on-site fuel oil storage facilities and primarily relies on the spot market for incremental supplies.

Renewable Energy Sources

The NSP System's renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2015, the NSP System was in compliance with mandated RPS, which require generation from renewable resources of 18 percent and 12.9 percent of NSP-Minnesota and NSP-Wisconsin electric retail sales, respectively.

- Renewable energy comprised 23.3 percent and 24.2 percent of the NSP System's total energy for 2015 and 2014, respectively;
- Wind energy comprised 13.6 percent and 13.7 percent of the total energy for 2015 and 2014, respectively;
- Hydroelectric energy comprised 7.3 percent and 7.8 percent of the total energy for 2015 and 2014, respectively; and
- Biomass and solar power comprised approximately 2.4 percent and 2.7 percent of the total energy for 2015 and 2014, respectively.

The NSP System also offers customer-focused renewable energy initiatives. Windsource allows customers in Minnesota, Wisconsin, and Michigan to purchase a portion or all of their electricity from renewable sources. In 2015, the number of customers utilizing Windsource increased to approximately 50,000 from 43,000 in 2014.

Additionally, to encourage the growth of solar energy on the system, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards program. Over 1,458 PV systems with approximately 18.3 MW of aggregate capacity and over 915 PV systems with approximately 11.1 MW of aggregate capacity have been installed in Minnesota under this program as of Dec. 31, 2015 and 2014, respectively.

Wind — The NSP System acquires the majority of its wind energy from PPAs with wind farm owners. Currently, the NSP System has more than 120 of these agreements in place, with facilities ranging in size from under one MW to more than 200 MW. The NSP System owns and operates four wind farms which have the capacity to generate 652 MWs.

- Collectively, the NSP System had approximately 2,210 and 1,860 MWs of wind energy on its system at the end of 2015 and 2014, respectively. In addition to receiving purchased wind energy under these agreements, the NSP System also typically receives wind RECs, which are used to meet state renewable resource requirements.
- The average cost per MWh of wind energy under the existing contracts was approximately \$42 and \$41 for 2015 and 2014, respectively. The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state-specific renewable resource requirements, and the year of contract execution. Generally, contracts executed in 2015 continued to benefit from improvements in technology, excess capacity among manufacturers, and motivation to commence new construction prior to the anticipated expiration of the Federal PTCs. In December 2015, the Federal PTCs were extended through 2019 with a phase down beginning in 2017.

Hydroelectric — The NSP System acquires its hydroelectric energy from both owned generation and PPAs. The NSP System owns 20 hydroelectric plants throughout Wisconsin and Minnesota which provide 277.5 MW of capacity. For 2015, PPAs provided approximately 34 MW of hydroelectric capacity. Additionally, the NSP System purchases approximately 725 MW of generation from Manitoba Hydro which is sourced primarily from its fleet of hydroelectric facilities.

Wholesale and Commodity Marketing Operations

NSP-Minnesota conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy-related products. NSP-Minnesota uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. NSP-Minnesota does not serve any wholesale requirements customers at cost-based regulated rates. See Item 7 for further discussion.

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Wisconsin's operations are regulated by the PSCW and the MPSC, within their respective states. In addition, each of the state commissions certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with the NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce. NSP-Wisconsin and NSP-Minnesota have been granted continued joint authorization from the FERC to make wholesale electric sales at market-based prices. NSP-Wisconsin is a transmission owning member of the MISO RTO.

The PSCW has a biennial base rate filing requirement. By June of each odd numbered year, NSP-Wisconsin must submit a rate filing for the test year beginning the following January. In recent years, NSP-Wisconsin has been submitting rate filings each year.

Fuel and Purchased Energy Cost Recovery Mechanisms — NSP-Wisconsin does not have an automatic electric fuel adjustment clause for Wisconsin retail customers. Instead, under Wisconsin rules, utilities submit a forward-looking annual fuel cost plan to the PSCW for approval. Once the PSCW approves the fuel cost plan, utilities defer the amount of any fuel cost under-collection or over-collection in excess of a two percent annual tolerance band, for future rate recovery or refund. Approval of a fuel cost plan and any rate adjustment for refund or recovery of deferred costs is determined by the PSCW after an opportunity for a hearing. Rate recovery of deferred fuel cost is subject to an earnings test based on the utility's most recently authorized ROE. Fuel cost under-collections that exceed the two percent annual tolerance band for a calendar year may not be recovered if the utility earnings for that year exceed the authorized ROE.

NSP-Wisconsin's retail electric rate schedules for Michigan customers include power supply cost recovery factors, which are based on 12-month projections. After each 12-month period, a reconciliation is submitted whereby over-collections are refunded and any under-collections are collected from the customers over the subsequent 12-month period.

Wisconsin Energy Efficiency Program — In Wisconsin, the primary energy efficiency program is funded by the state's utilities, but operated by independent contractors subject to oversight by the PSCW and the utilities. NSP-Wisconsin recovers these costs in rates charged to Wisconsin retail customers.

Capacity and Demand

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota Capacity and Demand.

Energy Sources and Related Transmission Initiatives

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota Energy Sources and Related Transmission Initiatives.

NSP-Wisconsin / American Transmission Company, LLC (ATC) - La Crosse, Wis. to Madison, Wis. Transmission Line — In October 2013, NSP-Wisconsin and ATC jointly filed an application with the PSCW for a Certificate of Public Convenience and Necessity (CPCN) for a new 345 KV transmission line that would extend from La Crosse, Wis. to Madison, Wis. NSP-Wisconsin's half of the line will be shared with three co-owners, Dairyland Power Cooperative, WPPI Energy and Southern Minnesota Municipal Power Agency-Wisconsin.

In April 2015, the PSCW issued its order approving a CPCN and route for the project. In June 2015, the PSCW denied two requests for rehearing. Two groups have appealed the CPCN Order to county circuit court. Court action is pending and the CPCN remains in full effect unless one of the parties seeks and receives a stay from the court and posts a bond to cover damages the utilities may incur due to delay. The 180-mile project is expected to cost approximately \$580 million. NSP-Wisconsin's portion of the investment is estimated to be approximately \$207 million. Construction on the line began in January 2016, with completion anticipated by late 2018.

2015 Electric Fuel Cost Recovery — NSP-Wisconsin's electric fuel costs for the year ended Dec. 31, 2015 were lower than authorized in rates and outside the two percent annual tolerance band established in the Wisconsin fuel cost recovery rules, primarily due to lower load as a result of mild weather, lower natural gas prices and lower purchased power prices in the MISO market. Accordingly, NSP-Wisconsin recorded a deferral of approximately \$9.2 million through Dec. 31, 2015. In the first quarter of 2016, NSP-Wisconsin will file a reconciliation of 2015 fuel costs with the PSCW. The amount of any potential refund is subject to review and approval by the PSCW, which is not expected until mid-2016.

Fuel Supply and Costs

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota Fuel Supply and Costs.

Wholesale and Commodity Marketing Operations

NSP-Wisconsin operates an integrated system with NSP-Minnesota. NSP-Wisconsin does not serve any wholesale requirements customers at cost-based regulated rates. See NSP-Minnesota Wholesale and Commodity Marketing Operations.

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo is regulated by the FERC with respect to its wholesale electric operations, accounting practices, hydroelectric licensing, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with the NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce. PSCo is authorized to make wholesale electric sales at market-based prices to customers outside its balancing authority area.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms — PSCo has several retail adjustment clauses that recover fuel, purchased energy and other resource costs:

- **ECA** — The ECA recovers fuel and purchased energy costs. Short-term sales margins are shared with retail customers through the ECA. The ECA is revised quarterly.
- **PCCA** — The PCCA recovers purchased capacity payments.
- **SCA** — The SCA recovers the difference between PSCo's actual cost of fuel and the amount of these costs recovered under its base steam service rates. The SCA rate is revised on a quarterly basis beginning in January 2015.
- **DSMCA** — The DSMCA recovers DSM, interruptible service option credit costs and performance initiatives for achieving various energy savings goals.
- **RESA** — The RESA recovers the incremental costs of compliance with the RES with a maximum of two percent of the customer's total bill.
- **Wind Energy Service** — Wind Energy Service is a premium service for customers who voluntarily choose to pay an additional charge for renewable resources.
- **TCA** — The TCA recovers costs associated with transmission investment outside of rate cases.
- **CACJA** — The CACJA recovers costs associated with implementing its compliance plan under the CACJA.

PSCo recovers fuel and purchased energy costs from its wholesale electric customers through a fuel cost adjustment clause approved by the FERC. PSCo's wholesale customers have agreed to pay the full cost of certain renewable energy purchase and generation costs through a fuel clause and in exchange receive RECs associated with those resources. The wholesale customers pay their jurisdictional allocation of production costs through a fully forecasted formula rate with true-up.

QSP Requirements — The CPUC established an electric QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to electric reliability and customer service. PSCo monitors and records, as necessary, an estimated customer refund obligation under the QSP. The CPUC extended the terms of the current QSP through 2018.

Capacity and Demand

Uninterrupted system peak demand for PSCo's electric utility for each of the last three years and the forecast for 2016, assuming normal weather conditions, is as follows:

	System Peak Demand (in MW)			
	2013	2014	2015	2016 Forecast
PSCo	6,678	6,152	6,284	6,493

The peak demand for PSCo's system typically occurs in the summer. The 2015 system peak demand for PSCo occurred on Aug. 5, 2015. The 2014 system peak demand was lower due to reduced wholesale loads and cooler summer weather. The forecast of 2016 system peak assumes normal weather conditions.

Energy Sources and Related Transmission Initiatives

PSCo expects to meet its system capacity requirements through existing electric generating stations, power purchases, new generation facilities, DSM options and phased expansion of existing generation at select power plants.

Purchased Power — PSCo has contracts to purchase power from other utilities and independent power producers. Long-term purchased power contracts typically require a periodic payment to secure the capacity and a charge for the associated energy actually purchased. PSCo also makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations, or to obtain energy at a lower cost.

Purchased Transmission Services — In addition to using its own transmission system, PSCo has contracts with regional transmission service providers to deliver energy to PSCo's customers.

Colorado ERP and All-Source Solicitation — The CPUC provided final approval to PSCo's plan in December 2013, which includes the following:

- The addition of 450 MW of wind generation PPAs became operational in 2015. These additional PPAs bring the installed wind capacity on PSCo's system in Colorado to 2,560 MW;
- The addition of 170 MW of utility-scale solar generation PPAs, of which 50 MW became operational in 2015 and the remaining 120 MW of utility-scale solar generation is expected to be operational by mid-2016. PSCo has approximately 80 MW of utility-scale solar and approximately 258 MW of customer-sited solar generation;
- The addition of 317 MW of natural gas fired generation PPAs come from existing power plants;
- The accelerated retirements of the coal-fired Arapahoe Unit 3 (45 MW) and Unit 4 (109 MW), which occurred in 2013; and
- The continued operation of Cherokee generating station's Unit 4 as a natural gas facility after 2017.

In addition, PSCo continues to execute on the remaining aspects of CACJA compliance including the recent completion of the new natural gas fired combined cycle unit at Cherokee and the ongoing addition of emissions controls at the Pawnee and Hayden stations. PSCo also retired the Cherokee Unit 3 in August 2015 and expects to retire Valmont Unit 5 coal-fired power plant by the end of 2017.

Brush, Colo. to Castle Pines, Colo. 345 KV Transmission Line — In April 2015, the CPUC granted a CPCN to construct a new 345 KV transmission line originating from Pawnee generating station, near Brush, Colo. and terminating at the Daniels Park substation, near Castle Pines, Colo. to be placed in service by 2022. The estimated project cost is \$178 million. The CPUC's decision requires that project construction begin no earlier than May 2020.

Boulder, Colo. Municipalization — In November 2011, a ballot measure was passed which authorized the formation and operation of a municipal utility and the issuance of enterprise revenue bonds, subject to certain restrictions, including the level of initial rates and debt service coverage. In May 2014, the City of Boulder (Boulder) City Council passed an ordinance to establish an electric utility.

In 2013, the CPUC ruled that Boulder may not be the retail service provider to any PSCo customers located outside Boulder city limits unless Boulder can establish that PSCo is unwilling or unable to serve those customers. The CPUC also ruled that it has jurisdiction over the transfer of any facilities to Boulder that currently serve any customers located outside Boulder city limits and will determine separation matters. The CPUC has declared that Boulder must receive CPUC transfer approval prior to any eminent domain actions. Boulder appealed this ruling to the Boulder District Court and in January 2015, the Boulder District Court affirmed the CPUC decision. The Boulder District Court also dismissed a condemnation action which Boulder had filed. The CPUC must complete the separation plan proceeding, outlined below, before Boulder may refile a condemnation proceeding.

In July 2015, Boulder filed an application with the CPUC requesting approval of its proposed separation plan. In August 2015, PSCo filed a motion to dismiss Boulder's separation proposal, arguing Boulder's request was not permissible under Colorado law. In December 2015, the CPUC granted the motion to dismiss the application in part, holding that Boulder had no right to condemn PSCo facilities used exclusively to serve customers located outside Boulder city limits. Other portions of Boulder's application were not dismissed, but are stayed until Boulder supplements its application at which time the CPUC will determine whether the application is complete and a proceeding can continue. The CPUC ordered a discovery process to allow Boulder to obtain technical information regarding the electric system and propose a new separation plan. Boulder is expected to refile its plan later this year. PSCo is also challenging Boulder's 2014 formation of its utility in a case that is now before the Colorado Court of Appeals.

Colorado “Our Energy Future” Plan — In January 2016, PSCo introduced the “Our Energy Future” Plan in Colorado. This proposal ties together innovative technology, economic development and customer initiatives to give customers more control over their energy use, prepare for the future energy demands of the state and keep rates competitive. The key components of the plan, which includes several filings with the CPUC, are as follows:

- Two Innovative Clean Technology pilot programs in partnership with leading companies to address electric battery efficiency and reliability including demonstrations to test microgrids and battery technologies for integration of distributed resources;
- Alignment of PSCo’s pricing in a more fair and equitable manner for Colorado customers;
- Introduction of Solar*Connect®, a new, cost-based program that will offer customers a choice to sign up for 100 percent solar power and add an incremental 50 MW of solar generation;
- Investing in natural gas reserves to take advantage of historically low natural gas prices by locking in current costs to provide long-term stable rates for customers;
- Exploring opportunities for up to 1,000 MW of additional renewable resources to be presented later this year for consideration by the CPUC; and
- Presenting an intelligent grid proposal later this year focusing on interactive meter technology that will improve customer choice and control of their energy use.

RES Compliance Plan — Colorado law mandates that at least 20 percent of PSCo’s energy sales are supplied by renewable energy through 2019, with the percentage increasing to 30 percent by 2020 and includes a distributed generation standard. PSCo is in compliance with the RES as of Dec. 31, 2015.

Energy Source Statistics

	Year Ended Dec. 31					
	2015		2014		2013	
	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
PSCo						
Coal	18,601	54%	18,274	53%	19,647	56%
Natural Gas	7,948	23	8,601	25	7,565	22
Wind ^(a)	6,699	19	6,472	19	6,750	19
Hydroelectric	662	2	617	2	655	2
Other ^(b)	705	2	294	1	250	1
Total	34,615	100%	34,258	100%	34,867	100%
 Owned generation	 22,981	 66%	 23,023	 67%	 22,873	 66%
Purchased generation	11,634	34	11,235	33	11,994	34
Total	34,615	100%	34,258	100%	34,867	100%

(a) This category includes wind energy de-bundled from RECs and also includes Windsource RECs. PSCo uses RECs to meet or exceed state resource requirements and may sell surplus RECs.

(b) Distributed generation from the Solar*Rewards program is not included, and was approximately 245, 197, and 172 million net KWh for 2015, 2014, and 2013, respectively.

Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for owned electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels.

PSCo Generating Plants	Coal		Natural Gas		Weighted Average Owned Fuel Cost
	Cost	Percent	Cost	Percent	
2015	\$ 1.75	75%	\$ 3.89	25%	\$ 2.29
2014	1.82	75	5.32	25	2.68
2013	1.84	80	4.86	20	2.45

See Items 1A and 7 for further discussion of fuel supply and costs.

Fuel Sources

Coal — PSCo normally maintains approximately 41 days of coal inventory. Coal supply inventories at Dec. 31, 2015 and 2014 were approximately 49 and 36 days usage, respectively. At Dec. 31, 2015, milder weather, purchase commitments and resolution of railcar congestion resulted in coal inventories being slightly above optimal levels. PSCo's generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Colorado and Wyoming. During 2015 and 2014, PSCo's coal requirements for existing plants were approximately 10.5 million tons and 10.3 million tons, respectively. The estimated coal requirements for 2016 are approximately 10.1 million tons.

PSCo has contracted for coal supply to provide 96 percent of its estimated coal requirements in 2016, and a declining percentage of requirements in subsequent years. PSCo's general coal purchasing objective is to contract for approximately 90 percent of requirements for the first year, 60 percent of requirements in year two, and 30 percent of requirements in year three. Remaining requirements will be filled through the procurement process or over-the-counter transactions.

PSCo has coal transportation contracts that provide for delivery of 100 percent and 86 percent of its coal requirements in 2016 and 2017, respectively. Coal delivery may be subject to interruptions or reductions due to operation of the mines, transportation problems, weather and availability of equipment.

Natural gas — PSCo uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas supplies for PSCo's power plants are procured under contracts to provide an adequate supply of fuel. However, as natural gas primarily serves intermediate and peak demand, any remaining forecasted requirements are able to be procured through a liquid spot market. The majority of natural gas supply under contract is covered by a long-term agreement with Anadarko Energy Services Company, the balance of natural gas supply contracts have variable pricing features tied to changes in various natural gas indices. PSCo hedges a portion of that risk through financial instruments. See Note 11 to the consolidated financial statements for further discussion.

Most transportation contract pricing is based on FERC approved transportation tariff rates. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery.

- At Dec. 31, 2015, PSCo's commitments related to gas supply contracts, which expire in various years from 2016 through 2023, were approximately \$750 million and commitments related to gas transportation and storage contracts, which expire in various years from 2016 through 2060, were approximately \$684 million.
- At Dec. 31, 2014, PSCo's commitments related to gas supply contracts were approximately \$902 million and commitments related to gas transportation and storage contracts were approximately \$685 million.

PSCo has limited on-site fuel oil storage facilities and primarily relies on the spot market for incremental supplies.

PSCo Natural Gas Reserves Investments — In January 2016, PSCo filed a request with the CPUC for approval of a long-term natural gas procurement and price hedging framework. Under the proposal, a wholly-owned subsidiary of PSCo, PSCo Gas Reserves Company (PGRCo), will be formed to partner with Wexpro, a subsidiary of Questar Corporation, to acquire, develop and operate natural gas producing properties on a 50/50 joint basis, with production recovered under cost of service pricing through PSCo's GCA. The CPUC has 240 days to review the proposed framework. If approved, PGRCo may invest up to approximately \$500 million in gas properties over 10 years, which is not reflected in the current base capital expenditures forecast.

The requested cost of service pricing formulas provide PGRCo and Wexpro different risks and incentives. For PGRCo, the investment would include all costs of property acquisition and development. The ROE would be based on PSCo's allowed ROE, adjusted up or down a maximum of 100 basis points, based on the price of gas produced relative to market prices.

Following approval of the framework, PSCo plans to partner with Wexpro to seek to identify and acquire specific natural gas producing properties that would be beneficial to PSCo's gas customers, and seek CPUC approval of these specific investments.

Renewable Energy Sources

PSCo's renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2015, PSCo was in compliance with mandated RPS, which require generation from renewable resources of 20 percent of electric retail sales.

- Renewable energy comprised 21.9 percent and 21.4 percent of PSCo's total energy for 2015 and 2014, respectively;

- Wind energy comprised 19.4 percent and 18.9 percent of the total energy for 2015 and 2014, respectively; and
- Hydroelectric, biomass and solar power comprised approximately 2.6 percent and 2.5 percent of the total energy for 2015 and 2014.

PSCo also offers customer-focused renewable energy initiatives. Windsource allows customers to purchase a portion or all of their electricity from renewable sources. In 2015, the number of customers utilizing Windsource increased to approximately 45,000 from 41,000 in 2014.

Additionally, to encourage the growth of solar energy on the system, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards program. Over 29,500 PV systems with approximately 258 MW of aggregate capacity and over 24,000 PV systems with approximately 221 MW of aggregate capacity have been installed in Colorado under this program as of Dec. 31, 2015 and 2014, respectively. Additionally, 24 community solar gardens with 16.6 MW of capacity and 14 gardens with 9.6 MW of capacity have been completed in Colorado as of Dec. 31, 2015 and 2014, respectively.

Wind — PSCo acquires the majority of its wind energy from PPAs with wind farm owners, primarily located in Colorado. Currently, PSCo has 19 of these agreements in place, with facilities ranging in size from two MW to over 300 MW.

- PSCo had approximately 2,560 MW and 2,340 MW of wind energy on its system at the end of 2015 and 2014, respectively. In addition to receiving purchased wind energy under these agreements, PSCo also typically receives wind RECs which are used to meet state renewable resource requirements.
- The average cost per MWh of wind energy under these contracts was approximately \$42 and \$45 in 2015 and 2014, respectively. The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state-specific renewable resource requirements, and the year of contract execution. Generally, contracts executed in 2015 continued to benefit from improvements in wind technology, excess capacity among manufacturers, and motivation to commence new construction prior to the anticipated expiration of the Federal PTCs. In December 2015, the Federal PTCs were extended through 2019 with a phase down beginning in 2017.

Wholesale and Commodity Marketing Operations

PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. PSCo uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. See Item 7 for further discussion.

SPS

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — The PUCT and NMPRC regulate SPS' retail electric operations and have jurisdiction over its retail rates and services and the construction of transmission or generation in their respective states. The municipalities in which SPS operates in Texas have original jurisdiction over SPS' rates in those communities. Each municipality can deny SPS' rate increases. SPS can then appeal municipal rate decisions to the PUCT, which hears all municipal rate denials in one hearing. The NMPRC also has jurisdiction over the issuance of securities. SPS is regulated by the FERC with respect to its wholesale electric operations, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce. As approved by the FERC, SPS operates within the SPP RTO and SPP IM wholesale market. SPS is authorized to make wholesale electric sales at market-based prices.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms — SPS has several retail adjustment clauses that recover fuel, purchased energy and other resource costs:

- **DCRF** — The DCRF rider recovers certain distribution costs in Texas that are not included in base rates.
- **EECRF** — The EECRF rider recovers costs associated with providing energy efficiency programs in Texas.
- **EE rider** — The EE rider recovers costs associated with providing energy efficiency programs in New Mexico.
- **FPPCAC** — The FPPCAC adjusts monthly to recover the difference between the actual fuel and purchased power costs and the amount included in base rates of SPS' New Mexico retail jurisdiction.
- **PCRF** — The PCRF rider allows recovery of certain purchased power costs in Texas that are not included in base rates.

- *RPS* — The RPS rider recovers deferred costs associated with renewable energy programs in New Mexico.
- *TCRF* — The TCRF rider recovers certain transmission infrastructure improvement costs and changes in wholesale transmission charges in Texas that are not included in base rates.

Fuel and purchased energy costs are recovered in Texas through a fixed fuel and purchased energy recovery factor, which is part of SPS' retail electric tariff. SO₂ and NO_x allowance revenues and costs are also recovered through the fixed fuel and purchased energy recovery factor. The regulations allow retail fuel factors to change up to three times per year.

The fixed fuel and purchased energy recovery factor provides for the over- or under-recovery of fuel and purchased energy expenses. Regulations also require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed four percent of the utility's annual fuel and purchased energy costs on a rolling 12-month basis, if this condition is expected to continue.

PUCT regulations require periodic examination of SPS' fuel and purchased energy costs, the efficient use of fuel and purchased energy, fuel acquisition and management policies and purchased energy commitments. SPS is required to file an application for the PUCT to retrospectively review fuel and purchased energy costs at least every three years. SPS will be required to file its next fuel reconciliation application by December 2016.

Each New Mexico utility operating with a FPPCAC as part of its tariff must file an application for continued use at intervals of no more than four years from the date the FPPCAC is approved or continued by the NMPRC. In October 2015, the NMPRC granted SPS authority to continue using its FPPCAC to collect its fuel and purchase power costs. SPS will be required to file a request for continuation of its FPPCAC by October 2019.

SPS recovers fuel and purchased energy costs from its wholesale customers through a monthly wholesale fuel and purchased economic energy cost adjustment clause accepted for filing by the FERC.

Capacity and Demand

Uninterrupted system peak demand for SPS for each of the last three years and the forecast for 2016, assuming normal weather conditions, is as follows:

	System Peak Demand (in MW)			
	2013	2014	2015	2016 Forecast
SPS	5,056	4,871	4,678	4,886

The peak demand for the SPS system typically occurs in the summer. The 2015 system peak demand for SPS occurred on July 28, 2015. The 2015 peak demand was lower due to wetter and cooler summer weather and a reduction in a partial requirements wholesale contractual agreement. The 2016 forecast assumes normal peak day weather.

Energy Sources and Related Transmission Initiatives

SPS expects to use existing electric generating stations, power purchases, DSM and new generation options to meet its system capacity requirements.

Purchased Power — SPS has contracts to purchase power from other utilities and independent power producers. Long-term purchased power contracts typically require a periodic payment to secure the capacity and a charge for the associated energy actually purchased. SPS also makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations or to obtain energy at a lower cost.

Purchased Transmission Services — SPS has contractual arrangements with SPP and regional transmission service providers, including PSCo, to deliver power and energy to its native load customers.

High Priority Incremental Load Study Report — In April 2014, the SPP Board of Directors approved the High Priority Incremental Load Study Report, a reliability assessment that evaluated the anticipated transmission needs of certain parts of the SPP resulting from expected load growth in the area. As a result of this study, SPS has received NTCs and conditional NTCs for 44 new transmission projects to be placed into service by 2020, some of which are already in service. SPS is developing plans for the remaining projects and submitting CCNs to the PUCT and the NMPRC. The estimated cost for these projects is \$203 million. These projects are intended to provide regional reliability benefits as well as the ability to serve the increase in load in southeastern New Mexico.

Potash Junction Substation to Roadrunner Substation 345 KV Transmission Line — In December 2014, the NMPRC issued a CCN for a new 345 KV transmission line from the Potash Junction substation to the Roadrunner substation, both near Carlsbad, N.M. The transmission line is 40 miles long and cost \$59.6 million. The line was placed into service in October 2015.

TUCO Substation to Yoakum County Substation to Hobbs Plant Substation 345 KV Transmission Line — In June 2015, SPS filed a CCN with the PUCT for the Yoakum County to Texas/New Mexico State line portion of this 345 KV line project and the PUCT is expected to approve this CCN in the first quarter of 2016. This line will connect the TUCO substation near Lubbock, Texas with the Yoakum County substation, continuing on to the Hobbs Plant substation near Hobbs, New Mexico. CCNs for the TUCO to Yoakum County line segment and for the Texas/New Mexico state line to Hobbs Plant segment are planned to be filed in mid-2016. The estimated project cost is \$242 million. This line is scheduled to be in service in 2020.

Hobbs Plant Substation to China Draw Substation 345 KV Transmission Line — The Hobbs Plant to China Draw transmission line will connect the Hobbs Plant substation to the China Draw substation near Malaga, N.M. with terminations at a proposed Kiowa substation near Carlsbad, N.M. and at the North Loving substation, near Loving, N.M. SPS plans to file a CCN for this line in New Mexico during spring 2016. The estimated project cost is \$139 million. The line is anticipated to be in service in 2018.

SPS Resource Plans — SPS was required to develop and implement a renewable portfolio plan by 2015, in which 15 percent of its energy to serve its New Mexico retail customers is produced by renewable resources. The requirement was met through PPAs, including wind, solar and distributive generation. In 2020, the renewable resource production requirement increases to 20 percent. In addition, SPS indicated that it was evaluating water supply issues at its Tolk facility and if additional investment is required to operate the plant through its existing life.

Texas Legislation — In June 2015, the Texas Governor signed HB 1535 into law. As a result, SPS may reduce regulatory lag through earlier inclusion of certain capital additions in rate base, as well as expediting the implementation of new rates. Key provisions of the bill are as follows:

- Utilities may include actual and estimated post-test year capital additions up through 30-days before the filing date;
- A new natural gas generating unit may be included in rate base as long as it is in service before the proposed effective rate date;
- Rates will go into effect 155 days after filing (previously it was 185 days). If the case is not final by this date, then a utility can go back and surcharge; and
- Establishes time limits for the PUCT to rule on a new generation plant request for a certificate of convenience and necessity.

Energy Source Statistics

	Year Ended Dec. 31					
	2015		2014		2013	
	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
SPS						
Coal	12,441	44%	12,770	48%	14,184	49%
Natural Gas	10,514	36	10,068	37	11,235	38
Wind ^(a)	5,252	19	3,762	14	3,507	12
Other ^(b)	150	1	180	1	167	1
Total	28,357	100%	26,780	100%	29,093	100%
 Owned generation	 16,480	 58%	 16,956	 63%	 18,814	 65%
Purchased generation	11,877	42	9,824	37	10,279	35
Total	28,357	100%	26,780	100%	29,093	100%

^(a) This category includes wind energy de-bundled from RECs and also includes Windsource RECs. SPS uses RECs to meet or exceed state resource requirements and may sell surplus RECs.

^(b) Distributed generation from the Solar*Rewards program is not included, was approximately 13, 10, and 11 million net KWh for 2015, 2014, and 2013, respectively.

Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for owned electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels.

SPS Generating Plants	Coal		Natural Gas		Weighted Average Owned Fuel Cost
	Cost	Percent	Cost	Percent	
2015	\$ 2.12	73%	\$ 3.11	27%	\$ 2.39
2014	2.07	71	4.76	29	2.85
2013	2.14	71	3.97	29	2.68

See Items 1A and 7 for further discussion of fuel supply and costs.

Fuel Sources

Coal — SPS purchases all of the coal requirements for its two coal facilities, Harrington and Tolk electric generating stations, from TUCO. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers. The coal supply contract with TUCO expires in December 2016 and 2017 for Harrington and Tolk, respectively. SPS normally maintains approximately 43 days of coal inventory. As of Dec. 31, 2015 and 2014, coal inventories at SPS were approximately 76 and 17 days supply, respectively. At Dec. 31, 2015, milder weather, purchase commitments and resolution of railcar congestion resulted in coal inventories being above optimal levels. TUCO has coal agreements to supply 87 percent of SPS' estimated coal requirements in 2016, and a declining percentage of the requirements in subsequent years. SPS' general coal purchasing objective is to contract for approximately 90 percent of requirements for the first year, 60 percent of requirements in year two, and 30 percent of requirements in year three.

Natural gas — SPS uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas for SPS' power plants is procured under contracts to provide an adequate supply of fuel; which typically is purchased with terms of one year or less. The transportation and storage contracts expire in various years from 2016 to 2033. All of the natural gas supply contracts have variable pricing that is tied to various natural gas indices.

Most transportation contract pricing is based on FERC and Railroad Commission of Texas approved transportation tariff rates. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. SPS' commitments related to gas supply contracts were approximately \$10 million and \$3 million and commitments related to gas transportation and storage contracts were approximately \$192 million and \$222 million at Dec. 31, 2015 and 2014, respectively.

SPS has limited on-site fuel oil storage facilities and primarily relies on the spot market for incremental supplies.

Renewable Energy Sources

SPS' renewable energy portfolio includes wind and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2015, SPS is in compliance with mandated RPS, which require generation from renewable resources of approximately four percent and 15 percent of Texas and New Mexico electric retail sales, respectively.

- Renewable energy comprised 19.0 percent and 14.7 percent of SPS' total energy for 2015 and 2014, respectively;
- Wind energy comprised 18.5 percent and 14.0 percent of the total energy for 2015 and 2014, respectively; and
- Solar power comprised approximately 0.5 percent and 0.4 percent of the total energy for 2015 and 2014, respectively.

SPS also offers customer-focused renewable energy initiatives. Windsource allows customers in New Mexico to purchase a portion or all of their electricity from renewable sources. The number of customers utilizing Windsource decreased to approximately 880 in 2015 from 900 in 2014.

Additionally, to encourage the growth of solar energy on the system in New Mexico, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards program. Over 144 PV systems with approximately 8.0 MW of aggregate capacity and over 129 PV systems with approximately 7.7 MW of aggregate capacity have been installed in New Mexico under this program as of Dec. 31, 2015 and 2014, respectively.

Wind — SPS acquires its wind energy from independent power producers (IPP) contracts and qualified facilities (QF) tariffs with wind farm owners, primarily located in the Texas Panhandle area of Texas and New Mexico. SPS currently has 37 of these agreements in place, with facilities ranging in size from under two MW to 250 MW for a total capacity greater than 1,800 MW.

- SPS had approximately 1,775 MW and 1,500 MW of wind energy on its system at the end of 2015 and 2014, respectively. In addition to receiving purchased wind energy under these agreements, SPS also typically receives wind RECs, which are used to meet state renewable resource requirements.
- The average cost per MWh of wind energy under the IPP contracts and QF tariffs was approximately \$24 and \$26 for 2015 and 2014, respectively. The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state-specific renewable resource requirements and the year of contract execution. Generally, contracts executed in 2015 continued to benefit from improvements in technology, excess capacity among manufacturers, and motivation to commence new construction prior to the anticipated expiration of the Federal PTCs. In December 2015, the Federal PTCs were extended through 2019 with a phase down beginning in 2017.

Wholesale and Commodity Marketing Operations

SPS conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. SPS uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. See Item 7 for further discussion.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, asset transactions and mergers, accounting practices and certain other activities of Xcel Energy Inc.'s utility subsidiaries and transmission-only subsidiaries, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy Inc.'s utility subsidiaries' activities, including regulation of retail rates and environmental matters. In addition to the matters discussed below, see Note 12 to the accompanying consolidated financial statements for a discussion of other regulatory matters.

FERC Order, New ROE Policy — In June 2014, the FERC adopted a new two-step ROE methodology for electric utilities. In March, 2015, FERC upheld the new ROE methodology and denied rehearing. The issue of how to apply the new FERC ROE methodology is being contested in various complaint proceedings. As part of a global settlement approved by the FERC in October 2015, three ROE complaints against SPS were resolved. FERC is not expected to issue orders in any litigated ROE complaint proceedings until at least mid-2016. See Note 12 to the consolidated financial statements for discussion of the MISO ROE Complaints.

SPS Asset Transfer to XEST — In October 2015, SPS submitted filings to the PUCT, NMPRC and Kansas Corporation Commission (KCC) seeking approval to transfer ownership of SPS' 345kV transmission assets in Kansas and Oklahoma to XEST at net book value, estimated at approximately \$103 million as of Dec. 31, 2015. After the proposed asset transfer, the transmission facilities would remain subject to SPP functional control, with revenue requirements recovered through the SPP Tariff. SPS and XEST also proposed to enter into a transmission operation and maintenance agreement (O&M Agreement) under which SPS would operate and maintain the transferred facilities and be reimbursed for providing those services to XEST at cost.

The KCC is expected to issue a decision within 10 months of the October filing. The hearings in the NMPRC and PUCT proceedings are scheduled for August 2016 and October 2016, respectively, with each decision expected several months later. Requests for FERC approval of the asset transfer and O&M Agreement were submitted in January 2016, and requested FERC action by June 30, 2016. Based on the procedural schedules for the required regulatory approvals, SPS expects the proposed asset transfer to take place no earlier than late 2016 or early 2017.

NERC Critical Infrastructure Protection Requirements — The FERC has approved Version 5 of NERC's critical infrastructure protection standards, which added additional requirements to strengthen grid security controls. Requirements must be applied by Xcel Energy to high and medium impact assets by April 1, 2016 and to low impact assets by April 1, 2017. Xcel Energy is currently in the process of implementing initiatives to meet the compliance deadlines. The additional cost for compliance is anticipated to be recoverable through rates.

NERC Physical Security Requirements — In November 2014, the FERC approved NERC's proposed critical infrastructure protection standard related to physical security for bulk electric system facilities. The new standard became enforceable in October 2015 with staggered milestone deliverable dates through 2016. Xcel Energy has performed an initial risk assessment and is in the process of developing physical security plans in accordance with the requirements of the standard. The additional cost for compliance is anticipated to be recoverable through rates.

SPP and MISO Complaints Regarding RTO Joint Operating Agreement (JOA) — SPP and MISO have been engaged in a longstanding dispute regarding the interpretation of their JOA, which is intended to coordinate RTO operations along the MISO/SPP system boundary. SPP and MISO disagree over MISO's authority to transmit power between the traditional MISO region in the Midwest and the Entergy system. Several cases were filed with the FERC by MISO and SPP between 2011 and 2014. In June 2014, the FERC set the issues for settlement judge and hearing procedures.

In January 2016, FERC approved a settlement between SPP, MISO and other parties that resolves various disputed matters and provide a defined settlement compensation plan by MISO to SPP. MISO will pay SPP \$16 million for the two-year retroactive period and \$16 million annually prospectively, subject to a true-up. Separate settlement discussions regarding the MISO tariff change to recover SPP charges are ongoing. NSP-Minnesota and NSP-Wisconsin expect to be able to recover any resulting MISO charges in retail rates. In January 2016, SPP filed a proposal regarding distribution of the revenues to SPP members, including SPS. FERC approval is pending. The revenue allocated to SPS is not expected to be material.

Electric Operating Statistics

Electric Sales Statistics

	Year Ended Dec. 31		
	2015	2014	2013
Electric sales (Millions of KWh)			
Residential	24,498	24,857	25,306
Large C&I	27,719	27,657	27,206
Small C&I	35,806	36,022	35,873
Public authorities and other	1,071	1,104	1,098
Total retail	89,094	89,640	89,483
Sales for resale	15,283	14,931	15,065
Total energy sold	104,377	104,571	104,548
Number of customers at end of period			
Residential	3,023,494	2,994,075	2,965,717
Large C&I	1,229	1,128	1,132
Small C&I	429,617	426,289	422,553
Public authorities and other	68,595	68,306	67,998
Total retail	3,522,935	3,489,798	3,457,400
Wholesale	47	44	65
Total customers	3,522,982	3,489,842	3,457,465
Electric revenues (Thousands of Dollars)			
Residential	\$ 2,891,371	\$ 2,956,576	\$ 2,906,208
Large C&I	1,689,695	1,789,742	1,694,720
Small C&I	3,303,838	3,382,750	3,248,586
Public authorities and other	136,730	143,442	138,126
Total retail	8,021,634	8,272,510	7,987,640
Wholesale	660,590	795,425	691,204
Other electric revenues	593,762	397,955	355,201
Total electric revenues	\$ 9,275,986	\$ 9,465,890	\$ 9,034,045
KWh sales per retail customer	25,290	25,686	25,882
Revenue per retail customer	\$ 2,277	\$ 2,370	\$ 2,310
Residential revenue per KWh	11.80¢	11.89¢	11.48¢
Large C&I revenue per KWh	6.10	6.47	6.23
Small C&I revenue per KWh	9.23	9.39	9.06
Total retail revenue per KWh	9.00	9.23	8.93
Wholesale revenue per KWh	4.32	5.33	4.59

Year Ended Dec. 31

	2015		2014		2013	
	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
Xcel Energy						
Coal	47,003	43%	49,123	46%	49,675	46%
Natural Gas	25,151	23	22,071	21	24,350	23
Wind ^(a)	18,186	17	16,478	15	15,738	14
Nuclear	12,895	12	13,503	12	12,177	11
Hydroelectric	4,001	4	4,203	4	3,900	4
Other ^(b)	1,456	1	1,795	2	1,704	2
Total	108,692	100%	107,173	100%	107,544	100%
 Owned generation	 73,279	 67%	 73,620	 69%	 70,936	 66%
Purchased generation	35,413	33	33,553	31	36,608	34
Total	108,692	100%	107,173	100%	107,544	100%

(a) This category includes wind energy de-bundled from RECs and also includes Windsource RECs. Xcel Energy uses RECs to meet or exceed state resource requirements and may sell surplus RECs.

(b) Includes energy from other sources, including solar, biomass, oil and refuse. Distributed generation from the Solar*Rewards program is not included, and was approximately 266, 222, and 198 million net KWh for 2015, 2014 and 2013, respectively.

NATURAL GAS UTILITY OPERATIONS

Overview

The most significant developments in the natural gas operations of the utility subsidiaries are uncertainty regarding political and regulatory developments that impact hydraulic fracturing, safety requirements for natural gas pipelines and the continued trend of declining use per residential and small C&I customer, as a result of improved building construction technologies, higher appliance efficiencies and conservation. From 2000 to 2015, average annual sales to the typical residential customer declined 17 percent, while sales to the typical small C&I customer declined 9 percent, each on a weather-normalized basis. Although wholesale price increases do not directly affect earnings because of natural gas cost-recovery mechanisms, high prices can encourage further efficiency efforts by customers.

The Pipeline and Hazardous Materials Safety Administration

Pipeline Safety Act — The Pipeline Safety, Regulatory Certainty, and Job Creation Act, signed into law in January 2012 (Pipeline Safety Act) requires additional verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. The DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) will require operators to re-confirm the maximum allowable operating pressure if records are inadequate. This process could cause temporary or permanent limitations on throughput for affected pipelines.

In addition, the Pipeline Safety Act requires PHMSA to issue reports and develop new regulations including: requiring use of automatic or remote-controlled shut-off valves; requiring testing of certain previously untested transmission lines; and expanding integrity management requirements. The Pipeline Safety Act also raises the maximum penalty for violating pipeline safety rules to \$2 million per day for related violations. While Xcel Energy cannot predict the ultimate impact Pipeline Safety Act will have on its costs, operations or financial results, it is taking actions that are intended to comply with the Pipeline Safety Act and any related PHMSA regulations as they become effective. PSCo and NSP-Minnesota can generally recover costs to comply with the transmission and distribution integrity management programs through the PSIA and GUIC riders, respectively.

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota’s retail natural gas operations are regulated by the MPUC and the NDPSC within their respective states. The MPUC has regulatory authority over security issuances, certain property transfers, mergers with other utilities and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota’s natural gas supply plans for meeting customers’ future energy needs. NSP-Minnesota is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce. NSP-Minnesota is subject to the DOT, the Minnesota Office of Pipeline Safety, the NDPSC and the SDPUC for pipeline safety compliance, including pipeline facilities used in electric utility operations for fuel deliveries.

Purchased Gas and Conservation Cost-Recovery Mechanisms — NSP-Minnesota’s retail natural gas rates for Minnesota and North Dakota include a PGA clause that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas, transportation service and storage service. The annual difference between the natural gas cost revenues collected through PGA rates and the actual natural gas costs is collected or refunded over the subsequent 12-month period.

NSP-Minnesota also recovers costs associated with transmission and distribution pipeline integrity management programs through its GUIC rider. Costs recoverable under the GUIC rider include funding for pipeline assessments as well as deferred costs from NSP-Minnesota’s existing sewer separation and pipeline integrity management programs. The MPUC and NDPSC have the authority to disallow recovery of certain costs if they find the utility was not prudent in its procurement activities.

Minnesota state law requires utilities to invest 0.5 percent of their state natural gas revenues in CIP. These costs are recovered through customer base rates and an annual cost-recovery mechanism for the CIP expenditures.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Minnesota was 774,044 MMBtu, which occurred on Jan. 12, 2015 and 752,931 MMBtu, which occurred on Jan. 2, 2014.

NSP-Minnesota purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of 620,180 MMBtu per day. In addition, NSP-Minnesota contracts with providers of underground natural gas storage services. These agreements provide storage for approximately 26 percent of winter natural gas requirements and 30 percent of peak day firm requirements of NSP-Minnesota.

NSP-Minnesota also owns and operates one LNG plant with a storage capacity of 2.0 Bcf equivalent and three propane-air plants with a storage capacity of 1.3 Bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 219,200 MMBtu of natural gas per day, or approximately 27 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

NSP-Minnesota is required to file for a change in natural gas supply contract levels to meet peak demand, to redistribute demand costs among classes, or to exchange one form of demand for another. In October 2015, the MPUC approved NSP-Minnesota’s contract demand levels for the 2014 through 2015 heating season. Demand levels filed with the MPUC in 2015 for the 2015 through 2016 heating season were approved in February 2016.

Natural Gas Supply and Costs

NSP-Minnesota actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, NSP-Minnesota conducts natural gas price hedging activity that has been approved by the MPUC.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by NSP-Minnesota’s regulated retail natural gas distribution business:

2015	\$	4.07
2014		6.17
2013		4.53

The cost of natural gas in 2015 decreased due to lower wholesale commodity prices.

NSP-Minnesota has firm natural gas transportation contracts with several pipelines, which expire in various years from 2016 through 2033.

NSP-Minnesota has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2015, NSP-Minnesota was committed to approximately \$207 million in such obligations under these contracts.

NSP-Minnesota purchases firm natural gas supply utilizing long-term and short-term agreements from approximately 32 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Minnesota to maintain competition from suppliers and minimize supply costs.

See Items 1A and 7 for further discussion of natural gas supply and costs.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — NSP-Wisconsin is regulated by the PSCW and the MPSC. The PSCW has a biennial base-rate filing requirement. By June of each odd-numbered year, NSP-Wisconsin must submit a rate filing for the test year period beginning the following January. NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce. NSP-Wisconsin is subject to the DOT, the PSCW and the MPSC for pipeline safety compliance.

Natural Gas Cost-Recovery Mechanisms — NSP-Wisconsin has a retail PGA cost-recovery mechanism for Wisconsin operations to recover the actual cost of natural gas and transportation and storage services. The PSCW has the authority to disallow certain costs if it finds NSP-Wisconsin was not prudent in its procurement activities.

NSP-Wisconsin's natural gas rate schedules for Michigan customers include a natural gas cost-recovery factor, which is based on 12-month projections.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Wisconsin was 158,719 MMBtu, which occurred on Jan. 7, 2015, and 163,520 MMBtu, which occurred on Jan. 6, 2014.

NSP-Wisconsin purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 139,127 MMBtu per day. In addition, NSP-Wisconsin contracts with providers of underground natural gas storage services. These agreements provide storage for approximately 31 percent of winter natural gas requirements and 34 percent of peak day firm requirements of NSP-Wisconsin.

NSP-Wisconsin also owns and operates one LNG plant with a storage capacity of 270,000 Mcf equivalent and one propane-air plant with a storage capacity of 2,700 Mcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 18,408 MMBtu of natural gas per day, or approximately 12 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

NSP-Wisconsin is required to file a natural gas supply plan with the PSCW annually to change natural gas supply contract levels to meet peak demand. NSP-Wisconsin's winter 2015-2016 supply plan was approved by the PSCW in September 2015.

Natural Gas Supply and Costs

NSP-Wisconsin actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, NSP-Wisconsin conducts natural gas price hedging activity that has been approved by the PSCW.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by NSP-Wisconsin's regulated retail natural gas distribution business:

2015	\$	4.11
2014		6.52
2013		4.51

The cost of natural gas supply, transportation service and storage service is recovered through various cost-recovery adjustment mechanisms. NSP-Wisconsin has firm natural gas transportation contracts with several pipelines, which expire in various years from 2016 through 2029.

NSP-Wisconsin has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2015, NSP-Wisconsin was committed to approximately \$55 million in such obligations under these contracts.

NSP-Wisconsin purchased firm natural gas supply utilizing long-term and short-term agreements from approximately 11 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Wisconsin to maintain competition from suppliers and minimize supply costs.

See Items 1A and 7 for further discussion of natural gas supply and costs.

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction under the Federal Natural Gas Act. PSCo is subject to the DOT and the CPUC with regards to pipeline safety compliance.

Purchased Natural Gas and Conservation Cost-Recovery Mechanisms — PSCo has retail adjustment clauses that recover purchased natural gas and other resource costs:

- *GCA* — The GCA recovers the actual costs of purchased natural gas and transportation to meet the requirements of its customers and is revised quarterly to allow for changes in natural gas rates.
- *DSMCA* — The DSMCA recovers costs of DSM and performance initiatives to achieve various energy savings goals.
- *PSIA* — The PSIA recovers costs associated with transmission and distribution pipeline integrity management programs and two projects to replace large transmission pipelines. The rider was extended through 2018.

QSP Requirements — The CPUC established a natural gas QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to natural gas leak repair time and customer service. The CPUC has extended the terms of the QSP through 2018.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for PSCo was 1,633,493 MMBtu, which occurred on March 4, 2015 and 2,116,747 MMBtu, which occurred on Dec. 30, 2014.

PSCo purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 1,818,277 MMBtu per day, which includes 854,852 MMBtu of natural gas held under third-party underground storage agreements. In addition, PSCo operates three company-owned underground storage facilities, which provide approximately 43,500 MMBtu of natural gas supplies on a peak day. The balance of the quantities required to meet firm peak day sales obligations are primarily purchased at PSCo’s city gate meter stations.

PSCo is required by CPUC regulations to file a natural gas purchase plan each year projecting and describing the quantities of natural gas supplies, upstream services and the costs of those supplies and services for the 12-month period of the following year. PSCo is also required to file a natural gas purchase report by October of each year reporting actual quantities and costs incurred for natural gas supplies and upstream services for the previous 12-month period.

Natural Gas Supply and Costs

PSCo actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, PSCo conducts natural gas price hedging activities that have been approved by the CPUC.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by PSCo’s regulated retail natural gas distribution business:

2015	\$	3.92
2014		4.91
2013		4.20

PSCo has natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2015, PSCo was committed to approximately \$1.1 billion in such obligations under these contracts, which expire in various years from 2016 through 2029.

PSCo purchases natural gas by optimizing a balance of long-term and short-term natural gas purchases, firm transportation and natural gas storage contracts. During 2015, PSCo purchased natural gas from approximately 32 suppliers.

See Items 1A and 7 for further discussion of natural gas supply and costs.

SPS

Natural Gas Facilities Used for Electric Generation

SPS does not provide retail natural gas service, but purchases and transports natural gas for certain of its generation facilities and operates natural gas pipeline facilities connecting the generation facilities to interstate natural gas pipelines. SPS is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce; and to the jurisdiction of the DOT and the PUCT for pipeline safety compliance.

See Items 1A and 7 for further discussion of natural gas supply and costs.

Natural Gas Operating Statistics

	Year Ended Dec. 31		
	2015	2014	2013
Natural gas deliveries (Thousands of MMBtu)			
Residential	135,394	152,269	150,280
C&I	86,093	95,879	92,849
Total retail	221,487	248,148	243,129
Transportation and other	125,263	124,000	125,057
Total deliveries	346,750	372,148	368,186
Number of customers at end of period			
Residential	1,814,321	1,795,190	1,776,849
C&I	156,306	155,515	154,646
Total retail	1,970,627	1,950,705	1,931,495
Transportation and other	6,981	6,594	6,320
Total customers	1,977,608	1,957,299	1,937,815
Natural gas revenues (Thousands of Dollars)			
Residential	\$ 1,042,884	\$ 1,320,207	\$ 1,126,859
C&I	547,165	727,071	586,548
Total retail	1,590,049	2,047,278	1,713,407
Transportation and other	82,032	95,460	91,272
Total natural gas revenues	\$ 1,672,081	\$ 2,142,738	\$ 1,804,679
MMBtu sales per retail customer	112.39	127.21	125.88
Revenue per retail customer	\$ 807	\$ 1,050	\$ 887
Residential revenue per MMBtu	7.70	8.67	7.50
C&I revenue per MMBtu	6.36	7.58	6.32
Transportation and other revenue per MMBtu	0.65	0.77	0.73

GENERAL

Seasonality

The demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months, and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, Xcel Energy's operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. See Item 7 for further discussion.

Competition

Xcel Energy is a vertically integrated utility in all of its jurisdictions, subject to traditional cost-of-service regulation by state public utilities commissions. However, Xcel Energy is subject to different public policies that promote competition and the development of energy markets. Xcel Energy's industrial and large commercial customers have the ability to own or operate facilities to generate their own electricity. In addition, customers may have the option of substituting other fuels, such as natural gas, steam or chilled water for heating, cooling and manufacturing purposes, or the option of relocating their facilities to a lower cost region. Customers also have the opportunity to supply their own power with solar generation (depending on jurisdiction, rooftop solar or solar gardens) and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. Several states have policies designed to promote the development of solar and other distributed energy resources through significant incentive policies; with these incentives and federal tax subsidies, distributed generating resources are potential competitors to Xcel Energy's electric service business.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. As a result, Xcel Energy Inc.'s utility subsidiaries and their wholesale customers can purchase the output from generation resources of competing wholesale suppliers and use the transmission systems of the utility subsidiaries on a comparable basis to serve their native load. State public utilities commissions have created resource planning programs that promote competition in the acquisition of electricity generation resources used to provide service to retail customers. In addition, FERC Order 1000 seeks to establish competition for construction and operation of certain new electric transmission facilities. Xcel Energy Inc.'s utility subsidiaries also have franchise agreements with certain cities subject to periodic renewal. If a city elected not to renew the franchise agreement, it could seek alternative means for its citizens to access electric power or gas, such as municipalization. While each of Xcel Energy Inc.'s utility subsidiaries faces these challenges, Xcel Energy believes their rates and services are competitive with currently available alternatives.

ENVIRONMENTAL MATTERS

Xcel Energy's facilities are regulated by federal and state environmental agencies. These agencies have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. Xcel Energy has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Xcel Energy's facilities have been designed and constructed to operate in compliance with applicable environmental standards. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or what effect future laws or regulations may have upon Xcel Energy's operations. See Item 7 and Notes 12 and 13 to the consolidated financial statements for further discussion.

There are significant present and future environmental regulations to encourage the use of clean energy technologies and regulate emissions of GHGs to address climate change. Xcel Energy has undertaken a number of initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. If these future environmental regulations do not provide credit for the investments we have already made to reduce GHG emissions, or if they require additional initiatives or emission reductions, then their requirements would potentially impose additional substantial costs. We believe, based on prior state commission practice, we would recover the cost of these initiatives through rates.

Xcel Energy is committed to addressing climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner. Xcel Energy adopted a methodology for calculating CO₂ emissions based on the reporting protocols of The Climate Registry, a nonprofit organization that provides and compiles GHG emissions data from reporting entities. Starting in 2011, Xcel Energy began reporting GHG emissions to the EPA under the EPA's mandatory GHG Reporting Program.

Based on The Climate Registry's current reporting protocol, Xcel Energy estimated that its current electric generating portfolio emitted approximately 56.6 million and 57.6 million tons of CO₂ in 2015 and 2014, respectively. Xcel Energy also estimated emissions associated with electricity purchased for resale to Xcel Energy customers from generation facilities owned by third parties. Xcel Energy estimates these non-owned facilities emitted approximately 10.2 million and 11.4 million tons of CO₂ in 2015 and 2014, respectively. Estimated total CO₂ emissions associated with service to Xcel Energy electric customers decreased by 2.2 million tons in 2015 compared to 2014. The decrease in emissions was associated with a decrease of 5.0 million net MWh of generation since 2011. The average annual decrease in CO₂ emissions since 2011 is approximately 2.9 million tons of CO₂ per year.

CAPITAL SPENDING AND FINANCING

See Item 7 for a discussion of expected capital expenditures and funding sources.

EMPLOYEES

As of Dec. 31, 2015, Xcel Energy had 11,601 full-time employees and 86 part-time employees, of which 5,514 were covered under collective-bargaining agreements. See Note 9 to the consolidated financial statements for further discussion.

EXECUTIVE OFFICERS

Ben Fowke, 57, Chairman of the Board, President and Chief Executive Officer and Director, Xcel Energy Inc., August 2011 to present. Chief Executive Officer, NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS January 2015 to present. Previously, President and Chief Operating Officer, Xcel Energy Inc., August 2009 to August 2011.

Christopher B. Clark, 49, President and Director, NSP-Minnesota, January 2015 to present. Previously, Regional Vice President, Rates and Regulatory Affairs, NSP-Minnesota, October 2012 to December 2014; Managing Director, Government and Regulatory Affairs, NSP-Minnesota, January 2012 to October 2012; Managing Attorney, Xcel Energy Inc., November 2007 to January 2012.

David L. Eves, 57, President and Director, PSCo, January 2015 to present. Previously, President, Director and Chief Executive Officer, PSCo, December 2009 to December 2014.

David T. Hudson, 55, President and Director, SPS, January 2015 to present. Previously, President, Director and Chief Executive Officer, SPS, January 2014 to December 2014; Director, Community Service & Economic Development, SPS, April 2011 to January 2014; Director, Strategic Planning, SPS, May 2008 to April 2011.

Kent T. Larson, 56, Executive Vice President and Group President Operations, Xcel Energy Inc., January 2015 to present. Previously, Senior Vice President, Group President Operations, Xcel Energy Services Inc., August 2014 to December 2014; Senior Vice President Operations, Xcel Energy Services Inc., September 2011 to August 2014; Chief Energy Supply Officer, Xcel Energy Services Inc., March 2010 to September 2011.

Teresa S. Madden, 60, Executive Vice President, Chief Financial Officer, Xcel Energy Inc., January 2015 to present. Previously, Senior Vice President, Chief Financial Officer, Xcel Energy Inc., September 2011 to December 2014; Vice President and Controller, Xcel Energy Inc., January 2004 to September 2011. Xcel Energy has previously announced that Teresa Madden will retire in 2016.

Marvin E. McDaniel, Jr., 56, Executive Vice President, Group President, Utilities, and Chief Administrative Officer, Xcel Energy Inc., January 2015 to present. Previously, Senior Vice President, Chief Administrative Officer, Xcel Energy Inc., August 2012 to December 2014; Senior Vice President and Chief Administrative Officer, Xcel Energy Services Inc., September 2011 to August 2012; Vice President and Chief Administrative Officer, Xcel Energy Services Inc., August 2009 to September 2011 and Vice President, Talent and Technology Business Areas, Xcel Energy Services Inc., August 2009 to September 2011.

Timothy O'Connor, 56, Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc., February 2013 to present. Previously, Acting Chief Nuclear Officer, NSP-Minnesota, September 2012 to February 2013; Vice President, Engineering and Nuclear Regulatory Compliance and Licensing July 2012 to September 2012; Monticello Site Vice President, May 2007 to July 2012.

Judy M. Pofert, 56, Senior Vice President, Corporate Secretary and Executive Services, Xcel Energy Inc., January 2015 to present. Previously, Vice President, Corporate Secretary, Xcel Energy Inc., May 2013 to December 2014; President, Director and Chief Executive Officer, NSP-Minnesota, August 2009 to May 2013.

Jeffrey S. Savage, 44, Senior Vice President, Controller, Xcel Energy Inc., January 2015 to present. Previously, Vice President, Controller, Xcel Energy Inc., September 2011 to December 2014; Senior Director, Financial Reporting, Corporate and Technical Accounting, Xcel Energy Services Inc., December 2009 to September 2011.

Mark E. Stoering, 55, President and Director, NSP-Wisconsin, January 2015 to present. Previously, President, Director and Chief Executive Officer, NSP-Wisconsin, January 2012 to December 2014; Vice President, Portfolio Strategy and Business Development, Xcel Energy Services Inc., August 2000 to December 2011.

Scott M. Wilensky, 59, Executive Vice President, General Counsel, Xcel Energy Inc., January 2015 to present. Previously, Senior Vice President, General Counsel, Xcel Energy Inc., September 2011 to December 2014; Vice President, Regulatory and Resource Planning, Xcel Energy Services Inc., September 2009 to September 2011.

No family relationships exist between any of the executive officers or directors.

Item 1A — Risk Factors

Like other companies in our industry, Xcel Energy is subject to a variety of risks, many of which are beyond our control. Important risks that may adversely affect the business, financial condition and results of operations are further described below. These risks should be carefully considered together with the other information set forth in this report and in future reports that Xcel Energy files with the SEC.

Oversight of Risk and Related Processes

A key accountability of the Board is the oversight of material risk, and our Board employs an effective process for doing so. As outlined below, management and each Board committee has responsibility for overseeing the identification and mitigation of key risks and reporting its assessments and activities to the full Board.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Management broadly considers our business, the utility industry, the domestic and global economies and the environment when identifying, assessing, managing and mitigating risk. Identification and analysis occurs formally through a key risk assessment process conducted by senior management, the financial disclosure process, the hazard risk management process and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing Xcel Energy's strategy. At the same time, the business planning process identifies areas in which there is a potential for a business area to take inappropriate risk to meet goals, and determines how to prevent inappropriate risk-taking.

At a threshold level, Xcel Energy has developed a robust compliance program and promotes a culture of compliance, including tone at the top, which mitigates risk. The process for risk mitigation includes adherence to our code of conduct and other compliance policies, operation of formal risk management structures and groups and overall business management to mitigate the risks inherent in the implementation strategy. Building on this culture of compliance, Xcel Energy manages and further mitigates risks through operation of formal risk management structures and groups, including management councils, risk committees and the services of internal corporate areas such as internal audit, the corporate controller and legal services.

Management communicates regularly with the Board and key stakeholders regarding risk. Senior management presents a periodic assessment of key risks to the Board. The presentation and the discussion of the key risks provides the Board with information on the risks management believes are material, including the earnings impact, timing, likelihood and controllability. Management also provides information to the Board in presentations and communications over the course of the year.

The Board approaches oversight, management and mitigation of risk as an integral and continuous part of its governance of the Company. First, the Board as a whole regularly reviews management's key risk assessment and analyzes areas of existing and future risks and opportunities. In addition, the Board assigns oversight of certain critical risks to each of its four standing committees to ensure these risks are well understood and given focused oversight by the committee with the most applicable expertise. The Audit Committee is responsible for reviewing the adequacy of risk oversight and affirming that appropriate oversight occurs. New risks are considered and assigned as appropriate during the annual Board and committee evaluation process, and committee charters and annual work plans are updated accordingly. Committees regularly report on their oversight activities and certain risk issues may be brought to the full Board for consideration where deemed appropriate to ensure broad Board understanding of the nature of the risk. Finally, the Board conducts an annual strategy session where the Company's future plans and initiatives are reviewed and confirmed.

Risks Associated with Our Business

Environmental Risks

We are subject to environmental laws and regulations, with which compliance could be difficult and costly.

We are subject to environmental laws and regulations that affect many aspects of our past, present and future operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. These laws and regulations require us to obtain and comply with a wide variety of environmental requirements including those for protected natural and cultural resources (such as wetlands, endangered species and other protected wildlife, and archaeological and historical resources), licenses, permits, inspections and other approvals. Environmental laws and regulations can also require us to restrict or limit the output of certain facilities or the use of certain fuels, shift generation to lower-emitting but potentially more costly facilities, install pollution control equipment at our facilities, clean up spills and other contamination and correct environmental hazards. Environmental regulations may also lead to shutdown of existing facilities, either due to the difficulty in assuring compliance or that the costs of compliance makes operation of the units no longer economical. Both public officials and private individuals may seek to enforce the applicable environmental laws and regulations against us. We may be required to pay all or a portion of the cost to remediate (i.e., clean-up) sites where our past activities, or the activities of certain other parties, caused environmental contamination. At Dec. 31, 2015, these sites included:

- Sites of former MGPs operated by our subsidiaries, predecessors or other entities; and
- Third party sites, such as landfills, for which we are alleged to be a PRP that sent hazardous materials and wastes.

We are also subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. Failure to meet the requirements of these mandates may result in fines or penalties, which could have a material effect on our results of operations. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations, financial position or cash flows.

In addition, existing environmental laws or regulations may be revised, and new laws or regulations may be adopted or become applicable to us, including but not limited to, regulation of mercury, NO_x, SO₂, CO₂ and other GHGs, particulates, cooling water intakes, water discharges and ash management. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

We are subject to physical and financial risks associated with climate change.

Climate change can create physical and financial risk. Physical risks from climate change can include changes in weather conditions, changes in precipitation and extreme weather events.

Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may result in decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of our service territory could also have an impact on our revenues. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand may raise electricity prices, which would increase the cost of energy we provide to our customers.

Severe weather impacts our service territories, primarily when thunderstorms, tornadoes and snow or ice storms occur. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Changes in precipitation resulting in droughts or water shortages, whether caused by climate change or otherwise, could adversely affect our operations, principally our fossil generating units. A negative impact to water supplies due to long-term drought conditions could adversely impact our ability to provide electricity to customers, as well as increase the price they pay for energy. We may not recover all costs related to mitigating these physical and financial risks.

Climate change may impact a region's economic health, which could impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of CO₂ emissions under section 111(d) of the CAA, or additional environmental regulation could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

Financial Risks

Our profitability depends in part on the ability of our utility subsidiaries to recover their costs from their customers and there may be changes in circumstances or in the regulatory environment that impair the ability of our utility subsidiaries to recover costs from their customers.

We are subject to comprehensive regulation by federal and state utility regulatory agencies. The utility commissions in the states where we operate regulate many aspects of our utility operations, including siting and construction of facilities, customer service and the rates that we can charge customers. The FERC has jurisdiction, among other things, over wholesale rates for electric transmission service, the sale of electric energy in interstate commerce and certain natural gas transactions in interstate commerce.

The profitability of our utility operations is dependent on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment. Our utility subsidiaries provide service at rates approved by one or more regulatory commissions. These rates are generally regulated and based on an analysis of the utility's costs incurred in a test year. Our utility subsidiaries are subject to both future and historical test years depending upon the regulatory mechanisms approved in each jurisdiction. Thus, the rates a utility is allowed to charge may or may not match its costs at any given time. While rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital, in a continued low interest rate environment there has been pressure pushing down ROE. There can also be no assurance that the applicable regulatory commission will judge all the costs of our utility subsidiaries to have been prudent, which could result in cost disallowances, or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of such costs. Changes in the long-term cost-effectiveness or changes to the operating conditions of our assets may result in early retirements and there is no assurance that regulators would allow full recovery of all remaining costs. Rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers. Furthermore, there could be changes in the regulatory environment that would impair the ability of our utility subsidiaries to recover costs historically collected from their customers.

Management currently believes these prudently incurred costs are recoverable given the existing regulatory mechanisms in place. However, adverse regulatory rulings or the imposition of additional regulations could have an adverse impact on our results of operations and hence could materially and adversely affect our ability to meet our financial obligations, including debt payments and the payment of dividends on our common stock.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot be assured that any of our current ratings or our subsidiaries' ratings will remain in effect for any given period of time, or that a rating will not be lowered or withdrawn entirely by a rating agency. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies. Any downgrade could lead to higher borrowing costs. Also, our utility subsidiaries may enter into certain procurement and derivative contracts that require the posting of collateral or settlement of applicable contracts if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment. As a result, we frequently need to access capital markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital markets are global in nature and are impacted by numerous issues and events throughout the world economy. Capital market disruption events and resulting broad financial market distress could prevent us from issuing new securities or cause us to issue securities with less than ideal terms and conditions, such as higher interest rates.

Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results. Changes in interest rates may also impact the fair value of the debt securities in the nuclear decommissioning fund and master pension trust, as well as our ability to earn a return on short-term investments of excess cash.

We are subject to credit risks.

Credit risk includes the risk that our customers will not pay their bills, which may lead to a reduction in liquidity and an increase in bad debt expense. Credit risk is comprised of numerous factors including the price of products and services provided, the overall economy and local economies in the geographic areas we serve, including local unemployment rates.

Credit risk also includes the risk that various counterparties that owe us money or product will breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we could incur losses.

One alternative available to address counterparty credit risk is to transact on liquid commodity exchanges. The credit risk is then socialized through the exchange central clearinghouse function. While exchanges do remove counterparty credit risk, all participants are subject to margin requirements, which create an additional need for liquidity to post margin as exchange positions change value daily. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires broad clearing of financial swap transactions through a central counterparty, which could lead to additional margin requirements that would impact our liquidity. However, we have taken advantage of an exception to mandatory clearing afforded to commercial end-users who are not classified as a major swap participant. The Board of Directors has authorized Xcel Energy and its subsidiaries to take advantage of this end-user exception.

We may at times have direct credit exposure in our short-term wholesale and commodity trading activity to various financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, such as SPP, PJM and MISO, in which any credit losses are socialized to all market participants.

We do have additional indirect credit exposures to various domestic and foreign financial institutions in the form of letters of credit provided as security by power suppliers under various long-term physical purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below the designated investment grade rating stipulated in the underlying long-term purchased power contracts, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in technical default under the contract, which would enable us to exercise our contractual rights.

Increasing costs associated with our defined benefit retirement plans and other employee benefits may adversely affect our results of operations, financial position or liquidity.

We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions, including mortality tables, have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock and bond market performance, changes in interest rates and changes in governmental regulations. In addition, the Pension Protection Act changed the minimum funding requirements for defined benefit pension plans with modifications that allowed additional flexibility in the timing of contributions. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving the company could trigger settlement accounting and could require the company to recognize material incremental pension expense related to unrecognized plan losses in the year these liabilities are paid.

Increasing costs associated with health care plans may adversely affect our results of operations.

Our self-insured costs of health care benefits for eligible employees have increased in recent years. Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our operating results, financial position and liquidity. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. Changes in industry standards utilized by management in key assumptions (e.g., mortality tables) could have a significant impact on future liabilities and benefit costs. Legislation related to health care could also significantly change our benefit programs and costs.

We must rely on cash from our subsidiaries to make dividend payments.

We are a holding company and our investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and our ability to service our indebtedness and pay dividends depends upon the operating cash flows of our subsidiaries and the payment dividends to us. Our subsidiaries are separate legal entities that have no obligation to pay any amounts due pursuant to our obligations or to make any funds available for dividends on our common stock. In addition, each subsidiary's ability to pay dividends to us depends on any statutory and/or contractual restrictions which may include requirements to maintain minimum levels of equity ratios, working capital or assets. Also, our utility subsidiaries are regulated by various state utility commissions, which possess broad powers to ensure that the needs of the utility customers are being met.

If our utility subsidiaries were to cease making dividend payments, our ability to pay dividends on our common stock or otherwise meet our financial obligations could be adversely affected.

Operational Risks

We are subject to commodity risks and other risks associated with energy markets and energy production.

We engage in wholesale sales and purchases of electric capacity, energy and energy-related products as well as natural gas. As a result we are subject to market supply and commodity price risk. Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis (mark-to-market accounting). Actual settlements can vary significantly from estimated fair values recorded, and significant changes from the assumptions underlying our fair value estimates could cause significant earnings variability.

If we encounter market supply shortages or our suppliers are otherwise unable to meet their contractual obligations, we may be unable to fulfill our contractual obligations to our customers at previously anticipated costs. Therefore, a significant disruption could cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Any significantly higher energy or fuel costs relative to corresponding sales commitments could have a negative impact on our cash flows and potentially result in economic losses. Potential market supply shortages may not be fully resolved through alternative supply sources and may cause short-term disruptions in our ability to provide electric and/or natural gas services to our customers. The impact of these cost and reliability issues vary in magnitude for each operating subsidiary depending upon unique operating conditions such as generation fuels mix, availability of water for cooling, availability of fuel transportation including rail shipments of coal, electric generation capacity, transmission, natural gas pipeline capacity, etc.

Our subsidiary, NSP-Minnesota, is subject to the risks of nuclear generation.

NSP-Minnesota's two nuclear stations, PI and Monticello, subject it to the risks of nuclear generation, which include:

- The risks associated with use of radioactive material in the production of energy, the management, handling, storage and disposal and the current lack of a long-term disposal solution for radioactive materials;
- Limitations on the amounts and types of insurance available to cover losses that might arise in connection with nuclear operations; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives. For example, similar to pensions, interest rate and other assumptions regarding decommissioning costs may change based on economic conditions and changes in the expected life of the asset may cause our funding obligations to change.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines and/or shut down a unit until compliance is achieved. Revised NRC safety requirements could necessitate substantial capital expenditures or a substantial increase in operating expenses. In addition, the Institute for Nuclear Power Operations reviews NSP-Minnesota's nuclear operations and nuclear generation facilities. Compliance with the Institute for Nuclear Power Operations' recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

If an incident did occur, it could have a material effect on our results of operations or financial condition. Furthermore, the non-compliance of other nuclear facilities operators or the occurrence of a serious nuclear incident at other facilities could result in increased regulation of the industry, which could then increase NSP-Minnesota's compliance costs and impact the results of operations of its facilities.

NSP-Wisconsin's production and transmission system is operated on an integrated basis with NSP-Minnesota's production and transmission system, and NSP-Wisconsin may be subject to risks associated with NSP-Minnesota's nuclear generation.

Our utility operations are subject to long-term planning risks.

Most electric utility investments are long-lived and are planned to be used for decades. Transmission and generation investments typically have long lead times, and therefore are planned well in advance of when they are brought in-service subject to long-term resource plans. These plans are based on numerous assumptions over the planning horizon such as: sales growth, customer usage, economic activity, costs, regulatory mechanisms, customer behavior, available technology and public policy. The electric utility sector is undergoing a period of significant change. For example, public policy has driven increases in appliance and lighting efficiency and energy efficient buildings, wider adoption and lower cost of renewable generation and distributed generation, shifts away from coal generation to decrease carbon dioxide emissions and increasing use of natural gas in electric generation driven by lower natural gas prices. These changes introduce additional uncertainty into long term planning which gives rise to a risk that the magnitude and timing of resource additions and growth in customer demand may not coincide, and that the preference for the types of additions may change from planning to execution.

The resource plans reviewed and approved by our state regulators assume continuation of the traditional utility cost of service model under which utility costs are recovered from customers as they receive the benefit of service. Xcel Energy is engaged in significant and ongoing infrastructure investment programs to accommodate distributed generation and maintain high system reliability. Xcel Energy is also investing in renewable and natural gas-fired generation to reduce our carbon dioxide emissions profile. Early plant retirements could expose us to premature financial obligations, which could result in less than full recovery of all remaining costs. Both decreasing use per customer driven by appliance and lighting efficiency and the availability of cost-effective distributed generation puts downward pressure on load growth. This could lead to under recovery of costs, excess resources to meet customer demand, and increases in electric rates.

Our natural gas transmission and distribution operations involve numerous risks that may result in accidents and other operating risks and costs.

Our natural gas transmission and distribution activities include a variety of inherent hazards and operating risks, such as leaks, explosions and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. We maintain insurance against some, but not all, of these risks and losses.

The occurrence of any of these events not fully covered by insurance could have a material effect on our financial position and results of operations. For our natural gas transmission or distribution lines located near populated areas, the level of potential damages resulting from these risks is greater.

Additionally, the operating or other costs that may be required in order to comply with potential new regulations, including the Pipeline Safety Act, could be significant. The Pipeline Safety Act requires verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. We have programs in place to comply with the Pipeline Safety Act and for systematic infrastructure monitoring and renewal over time. A significant incident could increase regulatory scrutiny and result in penalties and higher costs of operations.

Public Policy Risks

We may be subject to legislative and regulatory responses to climate change and emissions, with which compliance could be difficult and costly.

The EPA is regulating GHGs from power plants with state plans to achieve the EPA's goals due by September 2018. Increased public awareness and concern regarding climate change may result in more state, regional and/or federal requirements to reduce or mitigate the effects of GHGs. Legislative and regulatory responses related to climate change and new interpretations of existing laws through climate change litigation create financial risk as our electric generating facilities may be subject to additional regulation at either the state or federal level in the future. Such regulations could impose substantial costs on our system. International agreements could have an impact to the extent they lead to future federal or state regulations.

The United States continues to participate in international negotiations related to the United Nations Framework Convention on Climate Change (UNFCCC). In December 2015, the 21st Conference of the Parties to the UNFCCC reached consensus among 190 nations on an agreement (the Paris Agreement) that establishes a framework for GHG mitigation actions by all countries ("nationally determined contributions"), with a goal of holding the increase in global average temperature to below 2° Celsius above pre-industrial levels and an aspiration to limit the increase to 1.5° Celsius. The Paris Agreement could result in future additional GHG reductions in the United States.

We have been, and in the future may be, subject to climate change lawsuits. An adverse outcome in any of these cases could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant. Such payments or expenditures could affect results of operations, cash flows and financial condition if such costs are not recovered through regulated rates.

The form and stringency of GHG regulation in the power sector has become more clear with the finalization of the CPP by the EPA. The legality of the CPP is being challenged in the courts. In addition, uncertainties remain regarding implementation plans in our states (and the federal plan imposed by the EPA for states who do not submit approvable plans), including what opportunities are available to reduce costs, whether and what type of emission trading will be available, how states will allocate the reduction burden among utilities, what actions are creditable and the indirect impact of carbon regulation on natural gas and coal prices.

An important factor is our ability to recover the costs incurred to comply with any regulatory requirements in a timely manner. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations.

We are also subject to a significant number of proposed and potential rules that will impact our coal-fired and other generation facilities. These include rules associated with emissions of SO₂ and NO_x, mercury, regional haze, ozone and particulate matter, water intakes, water discharges and ash management. The costs of investment to comply with these rules could be substantial and in some cases would lead to early retirement of coal units. We may not be able to timely recover all costs related to complying with regulatory requirements imposed on us.

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. The FERC can now impose penalties of up to \$1 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties by regional entities, the NERC or the FERC for violations. If a serious reliability incident did occur, it could have a material effect on our operations or financial results. Some states have the authority to impose substantial penalties in the event of non-compliance.

We attempt to mitigate the risk of regulatory penalties through formal training on such prohibited practices and a compliance function that reviews our interaction with the markets under FERC and CFTC jurisdictions. However, there is no guarantee our compliance program will be sufficient to ensure against violations.

Macroeconomic Risks

Economic conditions impact our business.

Our operations are affected by local, national and worldwide economic conditions. Growth in our customer base is correlated with economic conditions. While the number of customers is growing, sales growth is relatively modest due to an increased focus on energy efficiency including federal standards for appliance and lighting efficiency and distributed generation, primarily solar PV. Instability in the financial markets also may affect the cost of capital and our ability to raise capital, which is discussed in the capital market risk section above.

Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay timely, increase customer bankruptcies, and may lead to increased bad debt.

Further, worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure, such as steel, copper, aluminum, etc., which may impact our ability to acquire sufficient supplies. Additionally, the cost of those commodities may be higher than expected.

Our operations could be impacted by war, acts of terrorism, threats of terrorism or disruptions in normal operating conditions due to localized or regional events.

Our generation plants, fuel storage facilities, transmission and distribution facilities and information systems may be targets of terrorist activities. Any such disruption could result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our financial condition and results of operations. The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have already incurred increased costs for security and capital expenditures in response to these risks. In addition, we may experience additional capital and operating costs to implement security for our plants, including our nuclear power plants under the NRC's design basis threat requirements. We have also already incurred increased costs for compliance with NERC reliability standards associated with critical infrastructure protection. In addition, we may experience additional capital and operating costs to comply with the NERC critical infrastructure protection standards as they are implemented and clarified.

The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms.

A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business. Because our generation, the transmission systems and local natural gas distribution companies are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the actions of a neighboring utility or an event (severe storm, severe temperature extremes, generator or transmission facility outage, pipeline rupture, railroad disruption, sudden and significant increase or decrease in wind generation or any disruption of work force such as may be caused by flu or other epidemic) within our operating systems or on a neighboring system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material impact on our financial condition and results.

The degree to which we are able to maintain day-to-day operations in response to unforeseen events will in part determine the financial impact of certain events on our financial condition and results. It is difficult to predict the magnitude of such events and associated impacts.

A cyber incident or cyber security breach could have a material effect on our business.

We operate in an industry that requires the continued operation of sophisticated information technology systems and network infrastructure. In addition, we use our systems and infrastructure to create, collect, use, disclose, store, dispose of and otherwise process sensitive information, including company data, customer energy usage data, and personal information regarding customers, employees and their dependents, contractors, shareholders and other individuals.

Our generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as the information processed in our systems (e.g., information about our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error. Our industry has begun to see an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or exposing us to liability. Our generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third party service providers' operations, could also negatively impact our business. In addition, such an event would likely receive regulatory scrutiny at both the federal and state level. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. These potential cyber security incidents and corresponding regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

We maintain security measures designed to protect our information technology systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cyber security incidents, including the resulting disability, or failures of assets or unauthorized access to assets or information. If our technology systems were to fail or be breached, or those of our third-party service providers, we may be unable to fulfill critical business functions, including effectively maintaining certain internal controls over financial reporting. We are unable to quantify the potential impact of cyber security incidents on our business.

Rising energy prices could negatively impact our business.

Although commodity prices are currently relatively low, if fuel costs increase, customer demand could decline and bad debt expense may rise, which could have a material impact on our results of operations. While we have fuel clause recovery mechanisms in most of our states, higher fuel costs could significantly impact our results of operations if costs are not recovered. Delays in the timing of the collection of fuel cost recoveries as compared with expenditures for fuel purchases could have an impact on our cash flows. Low fuel costs could have a positive impact on sales, although particularly on the southern part of our service territory, low oil prices could negatively impact oil and gas production activities. We are unable to predict future prices or the ultimate impact of such prices on our results of operations or cash flows.

Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather.

Our electric and natural gas utility businesses are seasonal, and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand depends heavily upon weather patterns throughout our service territory, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations, or cash flows.

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

Virtually all of the utility plant property of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS is subject to the lien of their first mortgage bond indentures.

Electric Utility Generating Stations:

NSP-Minnesota

Station, Location and Unit	Fuel	Installed	Summer 2015 Net Dependable Capability (MW)
Steam:			
A.S. King-Bayport, Minn., 1 Unit	Coal	1968	511
Sherco-Becker, Minn.			
Unit 1	Coal	1976	680
Unit 2	Coal	1977	682
Unit 3	Coal	1987	517 ^(a)
Monticello-Monticello, Minn., 1 Unit	Nuclear	1971	607
PI-Welch, Minn.			
Unit 1	Nuclear	1973	521
Unit 2	Nuclear	1974	519
Various locations, 4 Units.	Wood/Refuse-derived fuel	Various	36 ^(b)
Combustion Turbine:			
Angus Anson-Sioux Falls, S.D., 3 Units	Natural Gas	1994-2005	327
Black Dog-Burnsville, Minn., 2 Units	Natural Gas	1987-2002	282
Blue Lake-Shakopee, Minn., 6 Units	Natural Gas	1974-2005	453
High Bridge-St. Paul, Minn., 3 Units	Natural Gas	2008	538
Inver Hills-Inver Grove Heights, Minn., 6 Units	Natural Gas	1972	282
Riverside-Minneapolis, Minn., 3 Units	Natural Gas	2009	470
Various locations, 14 Units.	Natural Gas	Various	67
Wind:			
Grand Meadow-Mower County, Minn., 67 Units.	Wind	2008	101 ^(c)
Nobles-Nobles County, Minn., 134 Units	Wind	2010	201 ^(c)
Pleasant Valley-Mower County, Minn., 100 Units.	Wind	2015	200 ^(c)
Border-Rolette County, N.D., 75 Units	Wind	2015	150 ^(c)
		Total	<u>7,144</u>

(a) Based on NSP-Minnesota's ownership of 59 percent.

(b) Refuse-derived fuel is made from municipal solid waste.

(c) This capacity is only available when wind conditions are sufficiently high enough to support the noted generation values above. Therefore, the on-demand net dependable capacity is zero.

NSP-Wisconsin

Station, Location and Unit	Fuel	Installed	Summer 2015 Net Dependable Capability (MW)
Steam:			
Bay Front-Ashland, Wis., 3 Units.	Coal/Wood/Natural Gas	1948-1956	56
French Island-La Crosse, Wis., 2 Units	Wood/Refuse-derived fuel	1940-1948	16 ^(a)
Combustion Turbine:			
Flambeau Station-Park Falls, Wis., 1 Unit.	Natural Gas	1969	12
French Island-La Crosse, Wis., 2 Units	Natural Gas	1974	122
Wheaton-Eau Claire, Wis., 4 Units.	Natural Gas	1973	183
Hydro:			
Various locations, 63 Units.	Hydro	Various	135
		Total	<u>524</u>

(a) Refuse-derived fuel is made from municipal solid waste.

PSCo

Station, Location and Unit	Fuel	Installed	Summer 2015 Net Dependable Capability (MW)
Steam:			
Cherokee-Denver, Colo., 1 Unit	Coal	1968	352
Comanche-Pueblo, Colo.			
Unit 1	Coal	1973	325
Unit 2	Coal	1975	335
Unit 3	Coal	2010	500 ^(a)
Craig-Craig, Colo., 2 Units	Coal	1979-1980	83 ^(b)
Hayden-Hayden, Colo., 2 Units	Coal	1965-1976	237 ^(c)
Pawnee-Brush, Colo., 1 Unit	Coal	1981	505
Valmont-Boulder, Colo., 1 Unit	Coal	1964	184
Combustion Turbine:			
Cherokee-Denver, Colo., 3 Units	Natural Gas	2015	576
Blue Spruce-Aurora, Colo., 2 Units	Natural Gas	2003	264
Fort St. Vrain-Platteville, Colo., 6 Units	Natural Gas	1972-2009	969
Rocky Mountain-Keenesburg, Colo., 3 Units	Natural Gas	2004	580
Various locations, 6 Units	Natural Gas	Various	173
Hydro:			
Cabin Creek-Georgetown, Colo.			
Pumped Storage, 2 Units	Hydro	1967	210
Various locations, 9 Units	Hydro	Various	26
		Total	<u>5,319</u>

(a) Based on PSCo's ownership interest of 67 percent of Unit 3.

(b) Based on PSCo's ownership interest of 10 percent.

(c) Based on PSCo's ownership interest of 76 percent of Unit 1 and 37 percent of Unit 2.

SPS

Station, Location and Unit	Fuel	Installed	Summer 2015 Net Dependable Capability (MW)
Steam:			
Harrington-Amarillo, Texas, 3 Units	Coal	1976-1980	1,018
Tolk-Muleshoe, Texas, 2 Units	Coal	1982-1985	1,067
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1957-1965	254
Jones-Lubbock, Texas, 2 Units	Natural Gas	1971-1974	486
Maddox-Hobbs, N.M., 1 Unit	Natural Gas	1967	112
Nichols-Amarillo, Texas, 3 Units	Natural Gas	1960-1968	457
Plant X-Earth, Texas, 4 Units	Natural Gas	1952-1964	411
Combustion Turbine:			
Carlsbad-Carlsbad, N.M., 1 Unit	Natural Gas	1968	10
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1998	212
Jones-Lubbock, Texas, 2 Units	Natural Gas	2011-2013	338
Maddox-Hobbs, N.M., 1 Unit	Natural Gas	1963-1976	61
		Total	<u>4,426</u>

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2015:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	—	—	—
345 KV	8,425	1,152	2,630	8,108
230 KV	2,157	—	12,553	9,302
161 KV	395	1,577	—	—
138 KV	—	—	92	—
115 KV	7,502	1,810	4,925	12,427
Less than 115 KV	84,074	32,355	75,155	23,299

Electric utility transmission and distribution substations at Dec. 31, 2015:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity.....	349	204	229	444

Natural gas utility mains at Dec. 31, 2015:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	WGI
Transmission.....	136	—	2,278	11
Distribution.....	10,084	2,342	22,045	—

Item 3 — Legal Proceedings

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Additional Information

See Note 13 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Item 1, Item 7 and Note 12 to the consolidated financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

Item 4 — Mine Safety Disclosures

None.

PART II

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

Quarterly Stock Data

Xcel Energy Inc.’s common stock is listed on the New York Stock Exchange (NYSE). The trading symbol is XEL. The number of common shareholders of record as of Dec. 31, 2015 was approximately 64,202. The following are the intra-day high and low stock prices based on the NYSE Composite Transactions for the quarters of 2015 and 2014 and the dividends declared per share during those quarters. See Item 7 and Note 4 to the consolidated financial statements for further discussion of Xcel Energy Inc.’s dividend policy.

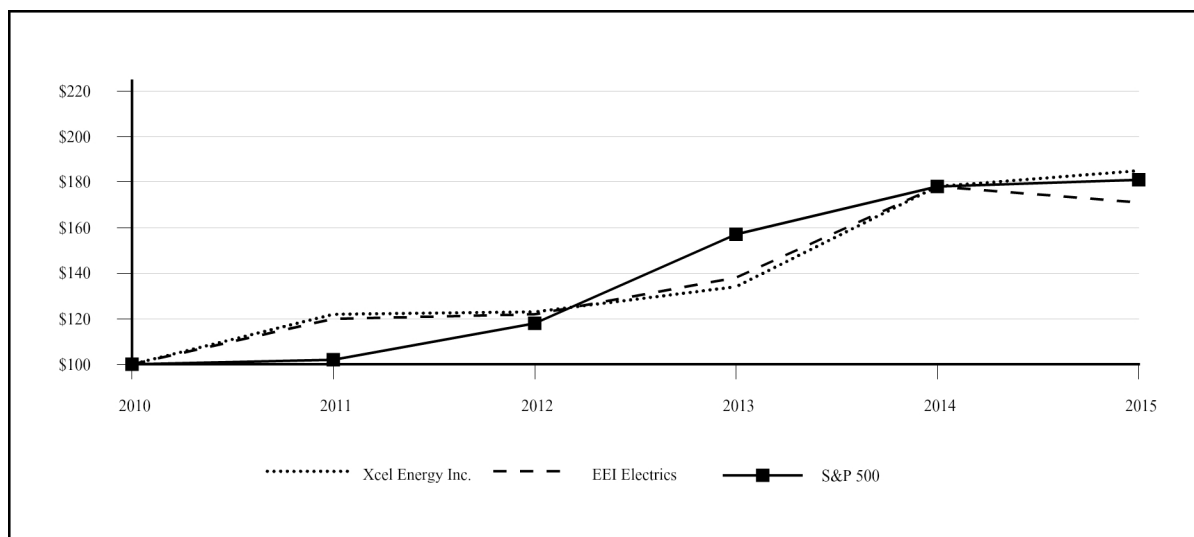
2015	High	Low	Dividends
First quarter.....	\$ 38.35	\$ 33.41	\$ 0.3200
Second quarter.....	35.35	31.76	0.3200
Third quarter.....	36.48	32.12	0.3200
Fourth quarter.....	37.25	34.33	0.3200
2014	High	Low	Dividends
First quarter.....	\$ 30.77	\$ 27.27	\$ 0.3000
Second quarter.....	32.37	29.83	0.3000
Third quarter.....	32.48	29.60	0.3000
Fourth quarter.....	37.58	30.18	0.3000

The following compares our cumulative TSR on common stock with the cumulative TSR of the EEI Investor-Owned Electrics Index and the S&P’s 500 Composite Stock Price Index over the last five years (assuming a \$100 investment on Dec. 31, 2010, and the reinvestment of all dividends).

The EEI Investor-Owned Electrics Index (market capitalization-weighted) currently includes 46 companies and is a broad measure of industry performance.

COMPARISON OF FIVE YEAR CUMULATIVE TOTAL RETURN*

Among Xcel Energy Inc., the EEI Investor-Owned Electrics
and the S&P 500



* \$100 invested on Dec. 31, 2010 in stock or index — including reinvestment of dividends. Fiscal years ending Dec. 31.

	2010	2011	2012	2013	2014	2015
Xcel Energy Inc.	\$ 100	\$ 122	\$ 123	\$ 134	\$ 178	\$ 185
EEI Investor-Owned Electrics	100	120	122	138	178	171
S&P 500	100	102	118	157	178	181

Securities Authorized for Issuance Under Equity Compensation Plans

Information required under Item 5 — Securities Authorized for Issuance Under Equity Compensation Plans is contained in Xcel Energy Inc.'s Proxy Statement for its 2016 Annual Meeting of Shareholders, which is incorporated by reference.

UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Exchange Act for the year ended Dec. 31, 2015:

Period	Issuer Purchases of Equity Securities			
	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
Jan. 1, 2015 — Jan. 31, 2015 ^(a)	12,051	\$ 37.85	—	—
Feb. 1, 2015 — Feb. 28, 2015	—	—	—	—
March 1, 2015 — March 31, 2015 ^(b)	19,441	\$ 34.75	—	—
April 1, 2015 — Dec. 31, 2015	—	—	—	—
Total	31,492		—	—

(a) Xcel Energy Inc. or one of its agents periodically purchases common shares in order to satisfy obligations under the Stock Equivalent Plan for Non-Employee Directors.

(b) Xcel Energy Inc. withholds stock to satisfy tax withholding obligations on vesting of awards of restricted stock under the Xcel Energy Executive Annual Incentive Award Plan.

Item 6 — Selected Financial Data

Set forth below is selected financial data for Xcel Energy related to the most five recent years ended Dec. 31. This information has been derived from and should be read in conjunction with the consolidated financial statements and notes appearing elsewhere in this annual report on Form 10-K.

(Millions of Dollars, Thousands of Shares, Except Per Share Data)	2015	2014	2013	2012	2011
Operating revenues	\$ 11,025	\$ 11,686	\$ 10,915	\$ 10,128	\$ 10,655
Operating expenses	9,024	9,738	9,067	8,306	8,873
Net income	984	1,021	948	905	841
Earnings available to common shareholders	984	1,021	948	905	834
Weighted average common shares outstanding:					
Basic	507,768	503,847	496,073	487,899	485,039
Diluted	508,168	504,117	496,532	488,434	485,615
EPS:					
Basic	\$ 1.94	\$ 2.03	\$ 1.91	\$ 1.86	\$ 1.72
Diluted	1.94	2.03	1.91	1.85	1.72
Dividends declared per common share	1.28	1.20	1.11	1.07	1.03
Total assets	39,054	36,958	33,907	31,141	29,497
Long-term debt ^(a)	12,491	11,500	10,911	10,144	8,849
Book value per share	20.89	20.20	19.21	18.19	17.44
Return on average common equity	9.5%	10.3%	10.3%	10.4%	10.1%
Ratio of earnings to fixed charges ^(b)	3.2	3.3	3.1	2.8	2.8
Non-GAAP:					
Ongoing earnings ^(c)	\$ 1,064	\$ 1,021	\$ 968	\$ 888	\$ 841
Ongoing diluted EPS ^(c)	2.09	2.03	1.95	1.82	1.72

^(a) Includes capital lease obligations.

^(b) See Exhibit 12.01.

^(c) See Item 7 for reconciliations of ongoing earnings and diluted EPS to GAAP earnings and diluted EPS.

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

Business Segments and Organizational Overview

Xcel Energy Inc. is a public utility holding company. Xcel Energy's operations included the activity of four utility subsidiaries that serve electric and natural gas customers in eight states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utilities serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with the TransCo subsidiaries, WYCO, a joint venture formed with CIG to develop and lease natural gas pipelines, storage and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the regulated utility operations.

Xcel Energy Inc.'s nonregulated subsidiary is Eloigne, which invests in rental housing projects that qualify for low-income housing tax credits.

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the 2015 EPS guidance and assumptions, are intended to be identified in this document by the words “anticipate,” “believe,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “potential,” “should” and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2015 (including the items described under Factors Affecting Results of Operations; and the other risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including “Risk Factors” in Item 1A of this Annual Report on Form 10-K and Exhibit 99.01 hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry, including the risk of a slow down in the U.S. economy or delay in growth recovery; trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; financial or regulatory accounting policies imposed by regulatory bodies; outcomes of regulatory proceedings; availability or cost of capital; and employee work force factors.

Management’s Strategic Plans

Xcel Energy strives to provide our investors an attractive total return and our customers with safe, clean and reliable energy services at a competitive price. This mission is enabled via four key strategic priorities:

- Improving utility performance;
- Driving operational excellence;
- Improving customer experience; and
- Investing for the future.

Below is a discussion of these objectives.

Improving utility performance

Xcel Energy is made up of several utility operating companies. As part of the regulatory process, each state will generally establish an authorized ROE. In many states, our utility operating companies earn less than the authorized ROE due to numerous factors including the timing of implementation of new rates, timing of capital investments, a regulatory commission not allowing the recovery of certain costs, the time period used as a test year for rate cases, fluctuations in sales, the impact of weather, unanticipated cost increases, etc. The difference between the authorized return and what is actually earned is referred to as an ROE gap. Xcel Energy is focused on reducing this gap over the next several years with specific goals as follows:

- Close the regulated ROE gap by 50 basis points by 2018 from the 2014 base level; and
- Derive 75 percent of our revenue from regulated operations via multi-year regulatory plans by 2017.

We continue to pursue regulatory and legislative changes to streamline rate case proceedings and optimize recovery, while improving our alignment with state policies and keeping pace with evolving customer preferences.

Driving operational excellence

Providing safe, reliable service to our customers has, and will continue to be, a fundamental priority. Keeping our costs competitive is also essential in terms of customer affordability, business results and sustained company success over time. To more closely align O&M expense growth with projected sales growth, Xcel Energy is working to limit the increase in annual O&M expense to zero to two percent without compromising reliability or safety. We intend to accomplish this objective by continually improving our processes, leveraging technology, proactively managing risk and maintaining a workforce that is prepared to meet the needs of our business today and tomorrow.

Improving customer experience

The utility landscape is changing, and we must continue to thoughtfully anticipate and address the future needs of our stakeholders, including our customers, policymakers, employees and shareholders. Adapting to this changing environment is critical to our long-term success. Our customers expect to have choices, and we are committed to providing options and solutions that they want and value at a competitive price. Our continued investments in clean energy is an example of this commitment to our customers. Environmental stewardship remains foundational to Xcel Energy and is designed to meet customer and policy maker expectations while creating shareholder value. We will continue to offer and expand our production of renewable energy, including wind and solar alternatives, and further develop and promote DSM, conservation and renewable programs.

Investing for the future

Sound investments today are necessary for tomorrow's success. Our base capital expenditures are projected to be approximately \$15.2 billion from 2016 through 2020. This capital forecast will grow rate base at a compounded average annual rate of approximately 3.7 percent, after reflecting the impact of the five year extension of bonus depreciation. Our capital investment plan includes continuing investments in transmission, adding new generation, reducing emissions in our power plants, refreshing our infrastructure, improving reliability, replacing natural gas pipelines and increasing the levels of renewable energy on our system. In addition, Xcel Energy has potential incremental capital investments opportunities that could increase the base capital forecast by an additional \$2.5 billion over the 2016-2020 timeframe. The potential incremental investment opportunities include renewables from the NSP System resource plan, renewables in Colorado as part of the "Our Energy Future" Plan, distribution grid modernization, natural gas reserves in Colorado and other investments. This would result in a total capital forecast of \$17.7 billion for 2016-2020 and a rate base growth rate of 5.5 percent, after reflecting the impact of the five year extension of bonus depreciation.

Xcel Energy has a proven track record of making sound investments. We proactively made the decision to balance our generation portfolio and expand our alternative energy production. Our customers, stakeholders and the environment are currently benefiting from these decisions and will continue to do so in the future.

Providing an attractive total return

Successful execution of our strategic objectives should allow Xcel Energy to continue to deliver an attractive total return for our shareholders. Through a combination of earnings growth and dividend yield, we plan to:

- Deliver long-term annual EPS growth of four percent to six percent, based on ongoing 2015 EPS of \$2.10, which was the mid-point of Xcel Energy's 2015 ongoing guidance range;
- Deliver annual dividend increases of five percent to seven percent (prior objective was two to four percent annually);
- Target a dividend payout ratio of 60 to 70 percent of annual ongoing EPS; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

We have successfully achieved our prior financial objectives, meeting or exceeding our earnings guidance range for eleven consecutive years and believe we are positioned to continue to deliver on our value proposition. Our ongoing earnings have grown approximately 6.2 percent and our dividend has grown approximately 4.1 percent annually from 2005 through 2015. In addition, our current senior unsecured debt credit ratings for Xcel Energy and its utility subsidiaries are in the BBB+ to A range.

Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on Xcel Energy's financial condition, results of operations and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying consolidated financial statements and the related notes to consolidated financial statements.

The only equity securities that are publicly traded are common shares of Xcel Energy Inc. The diluted earnings and EPS of each subsidiary as well as the ROE of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. Ongoing diluted EPS and ongoing ROE for Xcel Energy and by subsidiary are financial measures not recognized under GAAP. Ongoing diluted EPS is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary, adjusted for certain nonrecurring items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Ongoing ROE is calculated by dividing the net income or loss attributable to the controlling interest of Xcel Energy or each subsidiary, adjusted for certain nonrecurring items, by each entity's average common stockholders' or stockholder's equity. We use these non-GAAP financial measures to evaluate and provide details of earnings results. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. These non-GAAP financial measures should not be considered as alternatives to measures calculated and reported in accordance with GAAP.

Results of Operations

The following table summarizes the diluted EPS for Xcel Energy:

Diluted Earnings (Loss) Per Share	2015	2014	2013
PSCo.	\$ 0.92	\$ 0.90	\$ 0.91
NSP-Minnesota	0.85	0.80	0.79
SPS	0.25	0.26	0.23
NSP-Wisconsin.	0.15	0.14	0.12
Equity earnings of unconsolidated subsidiaries	0.04	0.04	0.04
Regulated utility	2.21	2.14	2.09
Xcel Energy Inc. and other.	(0.11)	(0.11)	(0.14)
Ongoing diluted EPS ^(a)	2.09	2.03	1.95
Loss on Monticello LCM/EPU project	(0.16)	—	—
SPS FERC complaint case orders	—	—	(0.04)
GAAP diluted EPS ^(a)	\$ 1.94	\$ 2.03	\$ 1.91

(a) Amounts may not add due to rounding.

Ongoing earnings exclude adjustments for certain items. For 2015, the adjustment to GAAP earnings is related to the Monticello nuclear facility LCM/EPU project. For 2013, the adjustment is related to the SPS FERC complaint case orders. See below for further discussion of the 2015 and 2013 adjustments and Note 12 to the consolidated financial statements for further discussion of the 2015 and 2013 adjustments.

Xcel Energy's management believes that ongoing earnings provide a meaningful comparison of earnings results and is representative of Xcel Energy's fundamental core earnings power. Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors, in determining whether performance targets are met for performance-based compensation, and when communicating its earnings outlook to analysts and investors.

2015 Adjustment to GAAP Earnings

Loss on Monticello LCM/EPU Project — In March 2015, the MPUC approved full recovery, including a return, on \$415 million of the project costs, inclusive of AFUDC, but only allow recovery of the remaining \$333 million of costs with no return on this portion of the investment for 2015 and beyond. As a result of this decision, Xcel Energy recorded a pre-tax charge of approximately \$129 million, or \$79 million net of tax, in the first quarter of 2015. See Note 12 to the consolidated financial statements for further discussion.

2013 Adjustment to GAAP Earnings

SPS FERC Orders — As a result of orders issued in August 2013 by the FERC for a SPS customer refund, a pre-tax charge of \$36 million was recorded in 2013. Of this amount, approximately \$30 million (\$26 million revenue reduction and \$4 million of interest) was attributable to periods prior to 2013 and not representative of ongoing earnings. As such, GAAP earnings include the total after tax amount of \$24.4 million and ongoing earnings exclude \$20.2 million. See Note 12 to the consolidated financial statements for further discussion.

Earnings Adjusted for Certain Items (Ongoing EPS)

2015 Comparison with 2014

Xcel Energy — Overall, ongoing earnings increased \$0.06 per share for 2015, which excludes an adjustment for a charge related to NSP-Minnesota's Monticello LCM/EPU project. Ongoing earnings increased primarily due to rate increases in various jurisdictions, non-fuel riders, a lower earnings test refund in Colorado and a decline in operating and maintenance expenses. These positive factors were partially offset by the impact of negative weather as well as higher depreciation, property taxes, interest charges and lower AFUDC.

PSCo — PSCo's ongoing earnings increased \$0.02 per share for 2015. Higher revenue primarily due to the CACJA rider (partially offset by an electric base rate decrease), as well as a natural gas rate increase (interim, subject to refund) effective in October 2015, lower estimated electric earnings test refunds and the positive impact of weather. These positive factors were partially offset by higher property taxes, depreciation, O&M expenses, interest charges and lower AFUDC.

NSP-Minnesota — NSP-Minnesota's ongoing earnings increased \$0.05 per share for 2015. Ongoing earnings were positively impacted by electric rate increases in Minnesota, North Dakota and South Dakota, and lower O&M expenses. These positive factors were partially offset by unfavorable weather, sales decline, higher depreciation, increased interest charges, property taxes and lower AFUDC.

SPS — SPS' ongoing earnings decreased \$0.01 per share for 2015. Although Texas electric rates rose as a result of the prior year rate case, this was reduced by the negative impact of the 2015 case. The net increase in electric rates was more than offset by additional depreciation, higher O&M expenses and lower AFUDC.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings increased \$0.01 per share for 2015. Higher electric revenues primarily driven by an electric rate increase and lower O&M expenses were partially offset by higher depreciation and lower natural gas margins.

2014 Comparison with 2013

Xcel Energy — Overall, ongoing earnings increased \$0.08 per share for 2014. Ongoing earnings increased as a result of higher electric and natural gas margins due to rate increases in various jurisdictions, weather-normalized sales growth and lower interest charges. These positive factors were partially offset by the unfavorable impact of milder weather, as well as higher expected O&M expenses, property taxes and depreciation. 2013 GAAP earnings include a \$0.04 per share charge for a potential SPS customer refund based on FERC orders issued in August 2013. This item was excluded from 2013 ongoing earnings.

PSCo — PSCo's ongoing earnings decreased \$0.01 per share for 2014. Higher natural gas and electric margins primarily due to rate increases, higher AFUDC, lower O&M expenses and weather-normalized sales growth were offset by higher property taxes, depreciation, accruals associated with the electric earnings test refund obligations and the unfavorable impact of weather.

NSP-Minnesota — NSP-Minnesota's ongoing earnings increased \$0.01 per share for 2014. Ongoing earnings were positively impacted by electric rate increases in Minnesota (interim, subject to refund) and North Dakota and weather-normalized sales growth. These items were partially offset by higher O&M expenses, the unfavorable impact of weather, lower AFUDC, increased property taxes and interest charges.

SPS — SPS' ongoing earnings increased \$0.03 per share for 2014. Electric rate increases in Texas and New Mexico and weather-normalized sales growth offset higher O&M and depreciation expenses.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings increased \$0.02 per share for 2014. An electric rate increase led to higher electric margin, while weather-normalized sales growth positively impacted both electric and natural gas margins. These increases were partially offset by additional O&M expenses.

Xcel Energy Inc. and other — Xcel Energy Inc. and other includes financing costs at the holding company and other items. Earnings improved by \$0.03 per share for 2014, largely due to lower financing costs as a result of the refinancing of junior subordinated notes.

Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2015 EPS compared with the same period in 2014.

Diluted Earnings (Loss) Per Share	Dec. 31
2014 GAAP and ongoing diluted EPS	\$ 2.03
Components of change — 2015 vs. 2014	
Higher electric margins	0.31
Lower conservation and DSM program expenses	0.09
Lower O&M expenses	0.01
Higher depreciation and amortization	(0.13)
Lower AFUDC — equity	(0.07)
Higher ETR	(0.06)
Higher taxes (other than income taxes)	(0.06)
Higher interest charges	(0.03)
Other, net	0.01
2015 ongoing diluted EPS ^(a)	2.09
Loss on Monticello LCM/EPU project	(0.16)
2015 GAAP diluted EPS ^(a)	\$ 1.94

(a) Amounts may not add due to rounding.

Diluted Earnings (Loss) Per Share	Dec. 31
2013 GAAP diluted EPS	\$ 1.91
SPS FERC complaint case orders	0.04
2013 ongoing diluted EPS	1.95
Components of change — 2014 vs. 2013	
Higher electric margins (excludes impact of SPS FERC complaint case orders)	0.26
Higher natural gas margins	0.06
Lower interest charges (excludes 2013 impact of SPS FERC complaint case orders)	0.01
Higher O&M expenses	(0.07)
Higher taxes (other than income taxes)	(0.06)
Higher depreciation and amortization	(0.05)
Higher conservation and DSM program expenses	(0.05)
Dilution from at-the-market program, direct stock purchase plan and benefit plans	(0.03)
Other, net	0.01
2014 ongoing and GAAP diluted EPS	\$ 2.03

The following table summarizes the ROE for Xcel Energy and its utility subsidiaries:

ROE — 2015	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Operating Companies ^(a)	Xcel Energy ^(a)
2015 ongoing ROE	9.33%	8.72%	7.56%	10.45%	8.91%	10.22%
Loss on Monticello LCM/ EPU project	—	(1.49)	—	(0.42)	(0.62)	(0.76)
2015 GAAP ROE	9.33%	7.23%	7.56%	10.03%	8.29%	9.46%

ROE — 2014	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Operating Companies ^(a)	Xcel Energy ^(a)
2014 ongoing and GAAP ROE	9.40%	8.82%	8.88%	10.85%	9.18%	10.33%

(a) Excluding the impact of negative/positive weather, the Operating Companies and Xcel Energy's ongoing ROEs equate to 9.07 percent and 10.40 percent, respectively, for 2015 and 9.06 percent and 10.18 percent, respectively, for 2014.

The following tables provide reconciliations of ongoing to GAAP earnings (net income) and ongoing to GAAP diluted EPS for the years ended Dec. 31:

(Millions of Dollars)	2015	2014	2013
Ongoing earnings	\$ 1,063.7	\$ 1,021.3	\$ 968.4
Loss on Monticello LCM/EPU project (2015) and SPS FERC complaint case orders (2013)	(79.2)	—	(20.2)
GAAP earnings	<u>\$ 984.5</u>	<u>\$ 1,021.3</u>	<u>\$ 948.2</u>
Diluted Earnings (Loss) Per Share	2015	2014	2013
Ongoing diluted EPS ^(a)	\$ 2.09	\$ 2.03	\$ 1.95
Loss on Monticello LCM/EPU project (2015) and SPS FERC complaint case orders (2013)	(0.16)	—	(0.04)
GAAP diluted EPS ^(a)	<u>\$ 1.94</u>	<u>\$ 2.03</u>	<u>\$ 1.91</u>

^(a) Amounts may not add due to rounding.

The following tables summarize the earnings contributions of Xcel Energy's business segments:

(Millions of Dollars)	2015	2014	2013
GAAP income (loss) by segment			
Regulated electric income	\$ 921.4	\$ 890.5	\$ 850.7
Regulated natural gas income	106.0	128.6	123.7
Other income ^(a)	15.8	59.5	44.6
Xcel Energy Inc. and other costs ^(a)	(58.7)	(57.3)	(70.8)
Total net income	<u>\$ 984.5</u>	<u>\$ 1,021.3</u>	<u>\$ 948.2</u>
Contributions to Diluted Earnings (Loss) Per Share	2015	2014	2013
GAAP earnings (loss) by segment			
Regulated electric	\$ 1.81	\$ 1.77	\$ 1.71
Regulated natural gas	0.21	0.25	0.25
Other ^(a)	0.03	0.12	0.09
Xcel Energy Inc. and other costs ^(a)	(0.11)	(0.11)	(0.14)
Total diluted EPS	<u>\$ 1.94</u>	<u>\$ 2.03</u>	<u>\$ 1.91</u>

^(a) Not a reportable segment. Included in all other segment results in Note 17 to the consolidated financial statements.

Statement of Income Analysis

The following discussion summarizes the items that affected the individual revenue and expense items reported in the consolidated statements of income.

Estimated Impact of Temperature Changes on Regulated Earnings — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity the average customer historically uses per degree of temperature. Accordingly, deviations in weather from normal levels can affect Xcel Energy's financial performance.

Degree-day or Temperature-Humidity Index (THI) data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. Cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one cooling degree-day, and each degree of temperature below 65° Fahrenheit is counted as one heating degree-day. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less sensitive to weather.

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction, based on regulatory practice. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales as defined above to derive the amount of demand associated with the weather impact.

The percentage increase (decrease) in normal and actual HDD, CDD and THI are provided in the following table:

	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014	2013 vs. Normal	2014 vs. 2013
HDD	(7.9)%	7.8%	(14.8)%	6.5%	0.4%
CDD	6.2	(2.6)	10.3	24.7	(20.3)
THI	(2.3)	(11.9)	14.1	21.8	(24.2)

Weather — The following table summarizes the estimated impact of temperature variations on EPS compared with sales under normal weather conditions:

	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014	2013 vs. Normal	2014 vs. 2013
Retail electric	\$ (0.020)	\$ 0.010	\$ (0.030)	\$ 0.088	\$ (0.078)
Firm natural gas	(0.018)	0.019	(0.037)	0.021	(0.002)
Total	<u>\$ (0.038)</u>	<u>\$ 0.029</u>	<u>\$ (0.067)</u>	<u>\$ 0.109</u>	<u>\$ (0.080)</u>

Sales Growth (Decline) — The following tables summarize Xcel Energy and its utility subsidiaries' sales growth (decline) for actual and weather-normalized sales for the years ended Dec. 31, compared with the previous year:

	2015 vs. 2014				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential ^(a)	1.1%	(3.2)%	(0.4)%	(6.1)%	(1.4)%
Electric C&I.	(0.4)	(0.6)	0.3	0.4	(0.2)
Total retail electric sales	0.1	(1.4)	0.1	(1.5)	(0.6)
Firm natural gas sales	(6.6)	(16.6)	N/A	(16.4)	(10.5)
	2015 vs. 2014				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential ^(a)	0.4%	(0.7)%	0.6%	(2.8)%	(0.3)%
Electric C&I.	(0.9)	(0.2)	0.7	0.8	(0.1)
Total retail electric sales	(0.5)	(0.4)	0.5	(0.3)	(0.2)
Firm natural gas sales	(2.0)	(1.1)	N/A	(1.7)	(1.7)

^(a) Extreme weather variations and additional factors such as windchill and cloud cover may not be reflected in weather-normalized and actual growth estimates.

Weather-normalized Electric 2015 Growth (Decline)

- PSCo's residential growth was primarily the result of customer additions, partially offset by lower use per customer. Commercial and industrial (C&I) decline was primarily due to reduced sales to certain large manufacturing customers and/or those that support the fracking industry.
- NSP-Minnesota's residential decrease was due to lower use per customer, partially offset by an increase in customer additions. C&I electric sales decreased as a result of lower use by large and small customers (e.g., services, retail trade, finance insurance and real estate industries), partially offset by higher use by certain large customers in the petroleum and food processing industries. The decline was partially reduced by an increase in the number of customers in both the small and large classes.
- SPS' residential growth reflects an increased number of customers. C&I also had an increase in customers, primarily in the oil and gas exploration and production industries. However, this was partially offset by reduced activity per customer within these industries, as well as less irrigation by agricultural customers due to wet weather.
- NSP-Wisconsin's residential decline was primarily attributable to lower use per customer, partially offset by customer additions. C&I electric sales growth was largely due to strong sales to large customers primarily in the oil and gas industries.

Weather-normalized Natural Gas 2015 Decline

- Across natural gas service territories, lower natural gas sales reflect a decline in customer use.

Weather-normalized sales for 2016 are projected to increase approximately 0.5 percent to 1.0 percent for retail electric customers and remain relatively flat for retail firm natural gas customers.

	2014 v. 2013				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential ^(a)	(2.8)%	(1.6)%	(0.4)%	(0.3)%	(1.8)%
Electric C&I	0.3	—	2.5	4.2	1.0
Total retail electric sales	(0.7)	(0.5)	1.8	2.8	0.2
Firm natural gas sales	(0.7)	7.3	N/A	7.4	2.3

	2014 vs. 2013				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential ^(a)	0.3%	0.7%	0.4%	0.5%	0.5%
Electric C&I	1.6	0.6	2.8	4.4	1.7
Total retail electric sales	1.2	0.6	2.3	3.3	1.3
Firm natural gas sales	5.2	3.6	N/A	3.8	4.6

^(a) Extreme weather variations and additional factors such as windchill and cloud cover may not be reflected in weather-normalized and actual growth estimates.

Weather-normalized Electric 2014 Growth

- NSP-Wisconsin's electric sales growth was largely due to strong sales to large C&I customers primarily in the oil, gas and sand mining industries.
- SPS' C&I growth was driven by continued expansion from oil and gas exploration and production in the Southeastern New Mexico, Permian Basin area.
- PSCo's electric sales growth was primarily due to customers in the food manufacturing, fracking and mining industries.
- NSP-Minnesota's electric sales growth was led by an increased number of customers for both residential and small C&I, as well as higher use per customer in small C&I.

Weather-normalized Natural Gas 2014 Growth

- Across our natural gas service territories, strong sales were experienced in 2014, which continued the trend that began in the last half of 2013.

Electric Revenues and Margin

Electric revenues and fuel and purchased power expenses are largely impacted by the fluctuation in the price of natural gas, coal and uranium used in the generation of electricity, but as a result of the design of fuel recovery mechanisms to recover current expenses, these price fluctuations have minimal impact on electric margin. The following table details the electric revenues and margin:

(Millions of Dollars)	2015	2014	2013
Electric revenues	\$ 9,276	\$ 9,466	\$ 9,034
Electric fuel and purchased power	(3,763)	(4,210)	(4,019)
Electric margin	<u>\$ 5,513</u>	<u>\$ 5,256</u>	<u>\$ 5,015</u>

The following tables summarize the components of the changes in electric revenues and electric margin for the years ended Dec. 31:

Electric Revenues

(Millions of Dollars)	2015 vs. 2014
Fuel and purchased power cost recovery	\$ (469)
Conservation and DSM program revenues (offset by expenses)	(62)
Estimated impact of weather	(23)
Trading	(14)
Retail rate increases ^(a)	101
Colorado CACJA non-fuel rider	94
Transmission revenue	91
PSCo earnings test refund	74
Non-fuel riders ^(b)	20
Other, net	(2)
Total decrease in electric revenues	<u>\$ (190)</u>

2015 Comparison with 2014 — Electric revenues decreased primarily due to lower fuel and purchased power cost recovery, which is offset in operating expense. This decrease was partially offset by various rate increases at NSP-Minnesota, NSP-Wisconsin and SPS as well as the non-fuel rider in Colorado.

Electric Margin

(Millions of Dollars)	2015 vs. 2014
Retail rate increases ^(a)	\$ 101
Colorado CACJA non-fuel rider	94
PSCo earnings test refunds	74
Transmission revenue, net of costs	47
Non-fuel riders ^(b)	20
Conservation and DSM program revenues (offset by expenses)	(62)
Estimated impact of weather	(23)
Other, net	6
Total increase in electric margin	<u>\$ 257</u>

^(a) Increase due to rate proceedings in Minnesota, South Dakota, Texas, North Dakota, New Mexico and Wisconsin. These increases were partially offset by a decline in Colorado retail base rates, which was more than offset by increased CACJA rider revenue as approved by the CPUC in the first quarter of 2015.

^(b) Primarily related to the Transmission Cost Recovery rider in Minnesota.

2015 Comparison to 2014 — The increase in electric margin was primarily due to the various rate increases at NSP-Minnesota, NSP-Wisconsin and SPS as well as the non-fuel rider in Colorado.

Electric Revenues

(Millions of Dollars)	2014 vs. 2013
Retail rate increases ^(a)	\$ 129
Trading	100
Fuel and purchased power cost recovery	78
Non-fuel riders	57
Transmission revenue	48
Conservation and DSM program revenues (offset by expenses)	44
Retail sales growth, excluding weather impact	24
Estimated impact of weather	(60)
Other, net	(14)
Total increase in ongoing electric revenues	<u>406</u>
SPS FERC complaint case orders ^(b)	26
Total increase in GAAP electric revenues	<u>\$ 432</u>

2014 Comparison with 2013 — Electric revenues increased primarily due to various rate increases across all of the utility subsidiaries, higher trading and increased fuel and purchased power cost recovery, which is offset in operating expense.

Electric Margin

(Millions of Dollars)	2014 vs. 2013
Retail rate increases ^(a)	\$ 129
Non-fuel riders	57
Conservation and DSM program revenues (offset by expenses)	44
Transmission revenue, net of costs	31
Retail sales growth, excluding weather impact	24
NSP-Wisconsin fuel recovery	11
Estimated impact of weather	(60)
Firm wholesale	(6)
Other, net	(15)
Total increase in ongoing electric margin	215
SPS FERC complaint case orders ^(b)	26
Total increase in GAAP electric margin	\$ 241

(a) The retail rate increases included final rates in Texas, Colorado (net of estimated earnings test refund obligations), New Mexico, Wisconsin and North Dakota and interim rates in Minnesota, which were subject to and net of estimated provision for refund.

(b) As a result of two orders issued by the FERC in August 2013, a pretax charge of approximately \$36 million (\$32 million in electric revenues, of which \$6 million relates to 2013 and \$26 million relates to periods prior to 2013, and \$4 million in interest charges) was recorded in 2013.

2014 Comparison to 2013 — The increase in electric margin was primarily due to the various rate increases across all of the utility subsidiaries.

Natural Gas Revenues and Margin

Total natural gas expense tends to vary with changing sales requirements and the cost of natural gas purchases. However, due to the design of purchased natural gas cost recovery mechanisms to recover current expenses for sales to retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin. The following table details natural gas revenues and margin:

(Millions of Dollars)	2015	2014	2013
Natural gas revenues	\$ 1,672	\$ 2,143	\$ 1,805
Cost of natural gas sold and transported	(905)	(1,372)	(1,083)
Natural gas margin	\$ 767	\$ 771	\$ 722

The following tables summarize the components of the changes in natural gas revenues and natural gas margin for the years ended Dec. 31:

Natural Gas Revenues

(Millions of Dollars)	2015 vs. 2014
Purchased natural gas adjustment clause recovery	\$ (462)
Estimated impact of weather	(30)
Conservation and DSM program revenues (offset by expenses)	(13)
Infrastructure and integrity riders, partially offset in O&M expenses	30
Purchased gas adjustment	5
Retail rate increases (Colorado, interim, subject to refund)	4
Other, net	(5)
Total decrease in natural gas revenues	\$ (471)

2015 Comparison to 2014 — Natural gas revenues decreased primarily due to the purchased natural gas adjustment clause recovery, which is offset in operating expense.

Natural Gas Margin

(Millions of Dollars)	2015 vs. 2014
Estimated impact of weather	\$ (30)
Conservation and DSM program revenues (offset by expenses)	(13)
Infrastructure and integrity riders, partially offset in O&M expenses	30
Purchased gas adjustment	5
Retail rate increases (Colorado, interim, subject to refund)	4
Total decrease in natural gas margin	<u>\$ (4)</u>

2015 Comparison to 2014 — Natural gas margins decreased primarily due to warmer winter weather and lower gas recovery rates primarily in NSP-Minnesota and PSCo.

Natural Gas Revenues

(Millions of Dollars)	2014 vs. 2013
Purchased natural gas adjustment clause recovery	\$ 293
Retail rate increases (Colorado)	19
PSIA rider (Colorado)	14
Retail sales growth, excluding weather impact	10
Estimated impact of weather	(1)
Other, net	3
Total increase in natural gas revenues	<u>\$ 338</u>

2014 Comparison to 2013 — Natural gas revenues increased primarily due to the purchased natural gas adjustment clause recovery, which is offset in operating expense.

Natural Gas Margin

(Millions of Dollars)	2014 vs. 2013
Retail rate increases (Colorado)	\$ 19
PSIA rider (Colorado), partially offset in O&M expenses	14
Retail sales growth, excluding weather impact	10
Estimated impact of weather	(1)
Other, net	7
Total increase in natural gas margin	<u>\$ 49</u>

2014 Comparison to 2013 — Natural gas margins increased primarily due to rate increases and the PSIA in Colorado.

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased \$4.7 million, or 0.2 percent, for 2015 compared with 2014. The following table summarizes the change in O&M expenses:

(Millions of Dollars)	2015 vs. 2014
Nuclear plant operations	\$ (22)
Transmission costs	(4)
Labor and contract labor	14
Plant generation costs	1
Other, net	6
Total decrease in O&M expenses	<u>\$ (5)</u>

2015 Comparison to 2014 — The decrease in O&M expenses for 2015 was due to the following:

- Nuclear expense decreased primarily driven by operational efficiencies and lower amortization of prior outages; and
- Labor and contract labor increased as a result of various projects and initiatives to improve business processes.

For 2014 compared with 2013, O&M expenses increased \$60.8 million, or 2.7 percent. The following table summarizes the change in O&M expenses:

(Millions of Dollars)	2014 vs. 2013
Nuclear plant operations and amortization	\$ 36
2013 gain on sale of transmission assets	14
Transmission costs	4
Electric and natural gas distribution expenses	1
Employee benefits	(6)
Plant generation costs	(3)
Other, net	15
Total increase in O&M expenses	<u>\$ 61</u>

2014 Comparison to 2013 — The increase in O&M expenses for 2014 was largely driven by the following:

- Nuclear cost increases are related to the amortization of prior outages and initiatives designed to improve the operational efficiencies of the plants; and
- Gain on sale of transmission assets relates to the 2013 gain associated with the sale of certain SPS' transmission assets to Sharyland.

Conservation and DSM Program Expenses — Conservation and DSM program expenses decreased \$77.1 million, or 25.5 percent, for 2015 compared with 2014. The decrease was primarily attributable to lower electric and gas recovery rates at NSP-Minnesota and PSCo. Lower conservation and DSM program expenses are generally offset by lower revenues.

Conservation and DSM program expenses increased \$41.0 million, or 15.7 percent, for 2014 compared with 2013. The increase was primarily attributable to higher electric recovery rates at NSP-Minnesota.

Depreciation and Amortization — Depreciation and amortization increased \$105.5 million, or 10.4 percent, for 2015 compared with 2014. The increase was primarily attributed to capital investments and lower amortization of the excess depreciation reserve in Minnesota, partially offset by Minnesota's amortization of the DOE settlement.

Depreciation and amortization increased \$41.2 million, or 4.2 percent, for 2014 compared with 2013. The increase was primarily attributable to the PI steam generator replacement placed in service in December 2013 and normal system expansion, partially offset by additional accelerated amortization of the excess depreciation reserve associated with certain Minnesota assets.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased \$45.8 million, or 9.8 percent, for 2015 compared with 2014. The increase was due to higher property taxes primarily in Colorado and Minnesota.

Taxes (other than income taxes) increased \$45.3 million, or 10.8 percent, for 2014 compared with 2013. The increase was primarily due to higher property taxes in Colorado, Minnesota and Texas.

AFUDC, Equity and Debt — AFUDC decreased \$46.0 million for 2015 compared with 2014. The decrease was primarily due to the implementation of the CACJA rider, facilitating earlier and alternative recovery of construction costs.

AFUDC increased \$1.3 million for 2014 compared with 2013. The increase was primarily due to construction related to the CACJA and the expansion of transmission facilities, partially offset by the portion of the Monticello LCM/EPU placed in service in July 2013 and the PI steam generator replacement placed in service in December 2013.

Interest Charges — Interest charges increased \$28.7 million, or 5.1 percent, for 2015 compared with 2014. The increase was primarily due to higher long-term debt levels, partially offset by refinancings at lower interest rates.

Interest charges decreased \$8.6 million, or 1.5 percent, for 2014 compared with 2013. The decrease was primarily due to refinancings at lower interest rates, partially offset by higher long-term debt levels. In addition, interest charges in 2013 reflected \$4 million of interest associated with the customer refund at SPS based on a FERC order, interest on customer refunds in Minnesota and the write off of \$6.3 million of unamortized debt expense related to the junior subordinated notes called in May 2013.

Income Taxes — Income tax expense increased \$18.9 million for 2015 compared with 2014. The increase was primarily due to a higher tax benefit for a carryback claim in 2014 and decrease in permanent plant-related deductions (e.g., AFUDC-equity) in 2015. The ETR was 35.5 percent for 2015 compared with 33.9 percent for 2014. See Note 6 to the consolidated financial statements for further discussion.

Income tax expense increased \$39.8 million for 2014 compared with 2013. The increase was primarily due to higher 2014 pretax earnings and recognition of additional R&E credits in 2013. These were partially offset by a 2014 tax benefit for prior year adjustments. The ETR was 33.9 percent for 2014 compared with 33.8 percent for 2013. See Note 6 to the consolidated financial statements for further discussion.

Xcel Energy Inc. and Other Results

The following tables summarize the net income and EPS contributions of Xcel Energy Inc. and its nonregulated businesses:

(Millions of Dollars)	Contribution to Xcel Energy's Earnings		
	2015	2014	2013
Xcel Energy Inc. financing costs	\$ (56.1)	\$ (51.8)	\$ (62.9)
Eloigne ^(a)	0.1	(0.5)	(0.8)
Xcel Energy Inc. taxes and other results	(2.7)	(5.0)	(7.1)
Total Xcel Energy Inc. and other costs	<u>\$ (58.7)</u>	<u>\$ (57.3)</u>	<u>\$ (70.8)</u>

(Earnings per Share)	Contribution to Xcel Energy's EPS		
	2015	2014	2013
Xcel Energy Inc. financing costs	\$ (0.11)	\$ (0.10)	\$ (0.13)
Eloigne ^(a)	—	—	—
Xcel Energy Inc. taxes and other results	—	(0.01)	(0.01)
Total Xcel Energy Inc. and other costs	<u>\$ (0.11)</u>	<u>\$ (0.11)</u>	<u>\$ (0.14)</u>

^(a) Amounts include gains or losses associated with sales of properties held by Eloigne.

Xcel Energy Inc.'s results include interest charges, which are incurred at Xcel Energy Inc. and are not directly assigned to individual subsidiaries.

Factors Affecting Results of Operations

Xcel Energy's utility revenues depend on customer usage, which varies with weather conditions, general business conditions and the cost of energy services. Various regulatory agencies approve the prices for electric and natural gas service within their respective jurisdictions and affect Xcel Energy's ability to recover its costs from customers. The historical and future trends of Xcel Energy's operating results have been, and are expected to be, affected by a number of factors, including those listed below.

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. While economic growth has been improving over the past year, management cannot predict whether this trend will be sustained going forward. Other events impact overall economic conditions and management cannot predict the impact of fluctuating energy prices, terrorist activity, war or the threat of war. However, Xcel Energy could experience a material impact to its results of operations, future growth or ability to raise capital resulting from a sustained general slowdown in economic growth or a significant increase in interest rates.

Fuel Supply and Costs

Xcel Energy Inc.'s operating utilities have varying dependence on coal, natural gas and uranium. Changes in commodity prices are generally recovered through fuel recovery mechanisms and have very little impact on earnings. However, availability of supply, the potential implementation of a carbon tax or emissions-related generation restrictions and unanticipated changes in regulatory recovery mechanisms could impact our operations. See Item 1 for further discussion of fuel supply and costs.

Pension Plan Costs and Assumptions

Xcel Energy has significant net pension and postretirement benefit costs that are measured using actuarial valuations. Inherent in these valuations are key assumptions including discount rates and expected return on plan assets. Xcel Energy evaluates these key assumptions at least annually by analyzing current market conditions, which include changes in interest rates and market returns. Changes in the related net pension and postretirement benefits costs and funding requirements may occur in the future due to changes in assumptions. The payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving the company would trigger settlement accounting and could require the company to recognize material incremental pension expense related to unrecognized plan losses in the year these liabilities are paid. For further discussion and a sensitivity analysis on these assumptions, see "Employee Benefits" under Critical Accounting Policies and Estimates.

Regulation

FERC and State Regulation — The FERC and various state and local regulatory commissions regulate Xcel Energy Inc.'s utility subsidiaries and TransCo subsidiaries. Decisions by these regulators can significantly impact Xcel Energy's results of operations. Xcel Energy expects to periodically file for rate changes based on changing energy market and general economic conditions.

The electric and natural gas rates charged to customers of Xcel Energy Inc.'s utility subsidiaries are approved by the FERC or the regulatory commissions in the states in which they operate. The rates are designed to recover plant investment, operating costs and an allowed return on investment. Rates charged by Xcel Energy Inc.'s TransCo subsidiaries and WGI are approved by the FERC. Xcel Energy requests changes in rates for utility services through filings with the governing commissions. Changes in operating costs can affect Xcel Energy's financial results, depending on the timing of filing general rate cases and the implementation of final rates. In addition to changes in operating costs, other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital. In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings.

Wholesale Energy Market Regulation — Wholesale energy markets in the Midwest and South Central U.S. are operated by MISO and SPP, respectively, to centrally dispatch all regional electric generation and apply a regional transmission congestion management system. NSP-Minnesota and NSP-Wisconsin are members of MISO and SPS is a member of SPP. NSP-Minnesota, NSP-Wisconsin and SPS expect to recover energy charges through either base rates or various recovery mechanisms. See Note 12 to the consolidated financial statements for further discussion.

Capital Expenditure Regulation — Xcel Energy Inc.'s utility subsidiaries make substantial investments in plant additions to build and upgrade power plants, and expand and maintain the reliability of the energy transmission and distribution systems. In addition to filings for increases in base rates charged to customers to recover the costs associated with such investments, the CPUC, MPUC, SDPUC, NDPSC and PUCT in certain instances have approved proposals to recover, through a rate rider, costs to upgrade generation plants and lower emissions, increase transmission investment cost, and/or increase distribution investment cost, and increase purchased power capacity cost. These non-fuel rate riders are expected to provide cash flows to enable recovery of costs incurred on a more timely basis. For wholesale electric transmission and production services, Xcel Energy has, consistent with FERC policy, implemented formula rates for each of the utility subsidiaries that will provide annual rate changes as transmission or production investments increase in a manner similar to the retail rate riders. In November 2014, the FERC approved transmission formula rates for XETD and XEST, which would apply to electric transmission assets the TransCos may own. NSP-Minnesota and NSP-Wisconsin have no cost-based wholesale production customers and therefore have not implemented a production formula rate.

Environmental Matters

Environmental costs include accruals for nuclear plant decommissioning and payments for storage of spent nuclear fuel, disposal of hazardous materials and waste, remediation of contaminated sites, monitoring of discharges to the environment and compliance with laws and permits with respect to emissions. A trend of greater environmental awareness and increasingly stringent regulation may continue to cause higher operating expenses and capital expenditures for environmental compliance.

Costs charged to operating expenses for nuclear decommissioning and spent nuclear fuel disposal expenses, environmental monitoring and disposal of hazardous materials and waste were approximately:

- \$292 million in 2015;
- \$292 million in 2014; and
- \$275 million in 2013.

Xcel Energy estimates an average annual expense of approximately \$338 million from 2016 through 2020 for similar costs. The precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates may fluctuate.

Capital expenditures for environmental improvements at regulated facilities were approximately:

- \$184 million in 2015;
- \$373 million in 2014; and
- \$517 million in 2013.

See Item 7 — Capital Requirements for further discussion.

Xcel Energy's operations are subject to federal and state laws and regulations related to air emissions, water discharges and waste management from various sources. Such laws and regulations impose monitoring and reporting requirements and may require Xcel Energy to obtain pre-approval for the construction or modification of projects that increase air emissions, water discharges or land disposal of wastes, obtain and comply with permits that contain emission, discharge and operational limitations, or install or operate pollution control equipment at facilities. Xcel Energy will likely be required to incur capital expenditures in the future to comply with these requirements for remediation of MGP and other legacy sites and various regulations for air emissions, water intake and discharge and waste disposal. Actual expenditures could vary from the estimates presented. The scope and timing of these expenditures cannot be determined until any new or revised regulations become final or until more information is learned about the need for remediation at the legacy sites.

Pollution control equipment can be required by federal and state regulations, such as those requiring mercury emission reductions, and by state or federal implementation plans, such as those to address visibility impairment, interstate air pollution impacts or attainment of NAAQS. Xcel Energy has installed and is operating control equipment needed to comply with the requirements of the federal Mercury and Air Toxic Standards Rule. Most recently, the EPA has adopted a federal visibility plan for Texas which imposes SO₂ emission limitations that reflect installation of dry scrubbers on Tolk Units 1 and 2, with compliance required by early 2021.

See Note 13 to the consolidated financial statements for further discussion of Xcel Energy's environmental contingencies.

Inflation

Inflation at its current level is not expected to materially affect Xcel Energy's prices or returns to shareholders. However, potential future inflation could result from economic conditions or the economic and monetary policies of the U.S. Government and the Federal Reserve. This could lead to future price increases for materials and services required to deliver electric and natural gas services to customers. These potential cost increases could in turn lead to increased prices to customers. If current low oil prices lead to sustained deflation, that could also reduce general economic activity although it may lead to lower electric and natural gas prices to customers.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Preparation of the consolidated financial statements and related disclosures in compliance with GAAP requires the application of accounting rules and guidance, as well as the use of estimates. The application of these policies involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements and disclosures, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and on the results reported. The following is a list of accounting policies and estimates that are most significant to the portrayal of Xcel Energy's financial condition and results, and require management's most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Each critical accounting policy has been reviewed and discussed with the Audit Committee of Xcel Energy Inc.'s Board of Directors on a quarterly basis.

Regulatory Accounting

Xcel Energy Inc. is a holding company with rate-regulated subsidiaries that are subject to the accounting for Regulated Operations, which provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if the competitive environment makes it probable that such rates will be charged and collected. Xcel Energy's rates are derived through the ratemaking process, which results in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs. In other businesses or industries, regulatory assets and regulatory liabilities would generally be charged to net income or OCI.

Each reporting period Xcel Energy assesses the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders and historical precedents are considered. Decisions made by regulatory agencies can directly impact the amount and timing of cost recovery as well as the rate of return on invested capital, and may materially impact Xcel Energy's results of operations, financial condition or cash flows.

As of Dec. 31, 2015 and 2014, Xcel Energy has recorded regulatory assets of \$3.2 billion and regulatory liabilities of \$1.6 billion. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs, in any such jurisdiction, ceases to be probable, Xcel Energy would be required to charge these assets to current net income or OCI. In assessing the probability of recovery of recognized regulatory assets, Xcel Energy noted no current or anticipated proposals or changes in the regulatory environment that it expects will materially impact the probability of recovery of the assets. See Note 15 to the consolidated financial statements for further discussion of regulatory assets and liabilities and Note 12 to the consolidated financial statements for further discussion of rate matters.

Income Tax Accruals

Judgment, uncertainty, and estimates are a significant aspect of the income tax accrual process that accounts for the effects of current and deferred income taxes. Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals require that judgment and estimates be made in the accrual process and in the calculation of the ETR. Changes in tax laws and rates may affect recorded deferred tax assets and liabilities and our ETR in the future. There exists the potential for federal tax reform that may significantly change the tax rules applicable to Xcel Energy. At this time, due to the inherent uncertainty of future legislation, any potential resulting impact cannot be reasonably estimated.

ETRs are highly impacted by assumptions. ETR calculations are revised every quarter based on best available year-end tax assumptions (income levels, deductions, credits, etc.); adjusted in the following year after returns are filed, with the tax accrual estimates being true-up to the actual amounts claimed on the tax returns; and further adjusted after examinations by taxing authorities have been completed.

In accordance with the interim period reporting guidance, income tax expense for the first three quarters in a year is based on the forecasted annual ETR. The forecasted ETR reflects a number of estimates including forecasted annual income, permanent tax adjustments and tax credits.

Accounting for income taxes also requires that only tax benefits that meet the more likely than not recognition threshold can be recognized or continue to be recognized. The change in the unrecognized tax benefits needs to be reasonably estimated based on evaluation of the nature of uncertainty, the nature of event that could cause the change and an estimated range of reasonably possible changes. Management will use prudent business judgment to derecognize appropriate amounts of tax benefits at any period end, and as new developments occur. Unrecognized tax benefits can be recognized as issues are favorably resolved and loss exposures decline.

We may adjust our unrecognized tax benefits and interest accruals to the updated estimates as disputes with the IRS and state tax authorities are resolved. These adjustments may increase or decrease earnings. See Note 6 to the consolidated financial statements for further discussion.

Employee Benefits

Xcel Energy's pension costs are based on an actuarial calculation that includes a number of key assumptions, most notably the annual return level that pension and postretirement health care investment assets are expected to earn in the future and the interest rate used to discount future pension benefit payments to a present value obligation. In addition, the pension cost calculation uses an asset-smoothing methodology to reduce the volatility of varying investment performance over time. See Note 9 to the consolidated financial statements for further discussion on the rate of return and discount rate used in the calculation of pension costs and obligations.

Pension costs are expected to decrease in 2016 and continue to decline in the following few years. Funding requirements increased in 2016 and then be flat in the following years. While investment returns exceeded the assumed levels in 2014, investment returns were below the assumed levels in 2013 and 2015. The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year. As these differences between the actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized in pension cost over the expected average remaining years of service for active employees which was approximately 11 years in 2015.

Based on current assumptions and the recognition of past investment gains and losses, Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be \$120.7 million in 2016 and \$117.0 million in 2017, while the actual pension costs were \$127.7 million in 2015 and \$126.5 million in 2014. The expected decrease in 2016 costs is due primarily to the reduction in historic loss amortization amounts including the 2008 market loss and an increase in the discount rate, which were offset by current year asset losses and a lowering of the expected return on asset assumption. Further, future year costs are expected to decrease primarily as a result of reductions in loss amortizations and an increase in expected return on assets due to planned future contributions and expected return of current assets.

In 2014, the Society of Actuaries published a new mortality table and projection scale that increased the overall life expectancy of males and females. Xcel Energy has reviewed its own population through a credibility analysis and adopted the RP 2014 table, with modifications, based on our population and specific experience. Further, at year-end 2015, Xcel Energy evaluated the updated projection table, MP 2015, and concluded that the methodology adopted at the end of 2014 is consistent with the new projection table and continues to be representative of Xcel Energy's population. Therefore, no changes are required.

At Dec. 31, 2015, Xcel Energy set the rate of return on assets used to measure pension costs at 6.87 percent, which is a 22 basis point decrease from Dec. 31, 2014. The rate of return used to measure postretirement health care costs is 5.80 percent at Dec. 31, 2015 and this is consistent with Dec. 31, 2014. Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Xcel Energy set the discount rates used to value the Dec. 31, 2015 pension and postretirement health care obligations at 4.66 percent and 4.65 percent, which represent a 55 basis point and 57 basis point increase from Dec. 31, 2014, respectively. Xcel Energy uses a bond matching study as its primary basis for determining the discount rate used to value pension and postretirement health care obligations. The bond matching study utilizes a portfolio of high grade (Aa or higher) bonds that matches the expected cash flows of Xcel Energy's benefit plans in amount and duration. The effective yield on this cash flow matched bond portfolio determines the discount rate for the individual plans. The bond matching study is validated for reasonableness against the Citigroup Pension Liability Discount Curve and the Citigroup Above Median Curve. At Dec. 31, 2015, these reference points supported the selected rate. In addition to these reference points, Xcel Energy also reviews general actuarial survey data to assess the reasonableness of the discount rate selected.

The following are the pension funding contributions across all four of Xcel Energy's pension plans, both voluntary and required, for 2013 through 2016:

- \$125.0 million in January 2016;
- \$90.1 million in 2015;
- \$130.6 million in 2014; and
- \$192.4 million in 2013.

For future years, we anticipate contributions will be made as necessary. These contributions are summarized in Note 9 to the consolidated financial statements. Future year amounts are estimates and may change based on actual market performance, changes in interest rates and any changes in governmental regulations. Therefore, additional contributions could be required in the future.

If Xcel Energy were to use alternative assumptions at Dec. 31, 2015, a one-percent change would result in the following impact on 2016 pension costs:

(Millions of Dollars)	Pension Costs	
	+1%	-1%
Rate of return	\$ (20.5)	\$ 20.9
Discount rate ^(a)	(8.6)	10.9

^(a) These costs include the effects of regulation.

Effective Jan. 1, 2016, the initial medical trend assumption decreased from 6.50 percent to 6.00 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is three years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

- Xcel Energy contributed \$18.3 million, \$17.1 million and \$17.6 million during 2015, 2014 and 2013, respectively, to the postretirement health care plans.
- Xcel Energy expects to contribute approximately \$12.3 million during 2016.

Xcel Energy recovers employee benefits costs in its regulated utility operations consistent with accounting guidance with the exception of the areas noted below.

- NSP-Minnesota recognizes pension expense in all regulatory jurisdictions as calculated using the aggregate normal cost actuarial method. Differences between aggregate normal cost and expense as calculated by pension accounting standards are deferred as a regulatory liability.
- Colorado, Texas, New Mexico and FERC jurisdictions allow the recovery of other postretirement benefit costs only to the extent that recognized expense is matched by cash contributions to an irrevocable trust. Xcel Energy has consistently funded at a level to allow full recovery of costs in these jurisdictions.
- PSCo and SPS recognize pension expense in all regulatory jurisdictions based on expense consistent with accounting guidance. The Texas and Colorado electric retail jurisdictions, and commencing in 2016, the Colorado gas retail jurisdiction, each record the difference between annual recognized pension expense and the annual amount of pension expense approved in their last respective general rate case as a deferral to a regulatory asset.

See Note 9 to the consolidated financial statements for further discussion.

Nuclear Decommissioning

Xcel Energy recognizes liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. These AROs are recognized at fair value as incurred and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, Xcel Energy estimates the fair value of its AROs using present value techniques, in which it makes various assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. When Xcel Energy revises any assumptions used to estimate AROs, it adjusts the carrying amount of both the ARO liability and the related long-lived asset. Xcel Energy accretes ARO liabilities to reflect the passage of time using the interest method.

A significant portion of Xcel Energy's AROs relates to the future decommissioning of NSP-Minnesota's nuclear facilities. The total obligation for nuclear decommissioning is expected to be funded 100 percent by the external decommissioning trust fund. The difference between regulatory funding (including depreciation expense less returns from the external trust fund) and expense recognized under current accounting guidance is deferred as a regulatory asset. The amounts recorded for AROs related to future nuclear decommissioning were \$2.141 billion and \$2.038 billion as of Dec. 31, 2015 and 2014, respectively. Based on their significance, the following discussion relates specifically to the AROs associated with nuclear decommissioning.

NSP-Minnesota obtains periodic cost studies in order to estimate the cost and timing of planned nuclear decommissioning activities. These independent cost studies are based on relevant information available at the time performed. Estimates of future cash flows for extended periods of time are by nature highly uncertain and may vary significantly from actual results. NSP-Minnesota is required to file a nuclear decommissioning study every three years. In December 2014, NSP-Minnesota submitted this filing to the MPUC, which covered all expenses over the decommissioning period of the nuclear plants, including decontamination and removal of radioactive material. The MPUC approved the study in October 2015.

The following key assumptions have a significant effect on the estimated nuclear obligation:

- **Timing** — Decommissioning cost estimates are impacted by each facility's retirement date and the expected timing of the actual decommissioning activities. Currently, the estimated retirement dates coincide with each unit's operating license with the NRC (i.e., 2030 for Monticello and 2033 and 2034 for PI's Unit 1 and 2, respectively). The estimated timing of the decommissioning activities is based upon the DECON method, which is required by the MPUC. By utilizing this method, which assumes prompt removal and dismantlement, these activities are expected to begin at the end of the license date and be completed for both facilities by 2091.

- **Technology and Regulation** — There is limited experience with actual decommissioning of large nuclear facilities. Changes in technology and experience as well as changes in regulations regarding nuclear decommissioning could cause cost estimates to change significantly. NSP-Minnesota's 2014 nuclear decommissioning filing assumed current technology and regulations.
- **Escalation Rates** — Escalation rates represent projected cost increases over time due to both general inflation and increases in the cost of specific decommissioning activities. NSP-Minnesota used an escalation rate of 4.36 percent in calculating the AROs related to nuclear decommissioning for the remaining operational period through the radiological decommissioning period. An escalation rate of 3.36 percent was utilized for the period of operating costs related to interim dry cask storage of spent nuclear fuel and site restoration.
- **Discount Rates** — Changes in timing or estimated expected cash flows that result in upward revisions to the ARO are calculated using the then-current credit-adjusted risk-free interest rate. The credit-adjusted risk-free rate in effect when the change occurs is used to discount the revised estimate of the incremental expected cash flows of the retirement activity. If the change in timing or estimated expected cash flows results in a downward revision of the ARO, the undiscounted revised estimate of expected cash flows is discounted using the credit-adjusted risk-free rate in effect at the date of initial measurement and recognition of the original ARO. Discount rates ranging from approximately four and seven percent have been used to calculate the net present value of the expected future cash flows over time.

Significant uncertainties exist in estimating the future cost of nuclear decommissioning including the method to be utilized, the ultimate costs to decommission, and the planned method of disposing spent fuel. If different cost estimates, life assumptions or cost escalation rates were utilized, the AROs could change materially. However, changes in estimates should have minimal impact on results of operations as NSP-Minnesota expects to continue to recover all costs in future rates.

Xcel Energy continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the varying assumptions and uncertainties for each area. The information and assumptions underlying many of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect the events and updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2015.

Derivatives, Risk Management and Market Risk

Xcel Energy Inc. and its subsidiaries are exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk. See Note 11 to the consolidated financial statements for further discussion of market risks associated with derivatives.

Xcel Energy is exposed to the impact of adverse changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, when necessary, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While Xcel Energy expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose Xcel Energy to some credit and non-performance risk.

Though no material non-performance risk currently exists with the counterparties to Xcel Energy's commodity derivative contracts, distress in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Distress in the financial markets may also impact the fair value of the securities in the nuclear decommissioning fund and master pension trust, as well as Xcel Energy's ability to earn a return on short-term investments of excess cash.

Commodity Price Risk — Xcel Energy Inc.'s utility subsidiaries are exposed to commodity price risk in their electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and for various fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Xcel Energy's risk management policy allows it to manage commodity price risk within each rate-regulated operation to the extent such exposure exists.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments. Xcel Energy's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

At Dec. 31, 2015, the fair values by source for net commodity trading contract assets were as follows:

(Thousands of Dollars)	Source of Fair Value	Futures / Forwards				
		Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures / Forwards Fair Value
NSP-Minnesota	1	\$ 2,699	\$ 5,959	\$ 1,575	\$ —	\$ 10,233
NSP-Minnesota	2	695	—	—	—	695
PSCo.	1	128	(16)	—	—	112
		<u>\$ 3,522</u>	<u>\$ 5,943</u>	<u>\$ 1,575</u>	<u>\$ —</u>	<u>\$ 11,040</u>

1 — Prices actively quoted or based on actively quoted prices.

2 — Prices based on models and other valuation methods.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing mechanisms for the years ended Dec. 31, were as follows:

(Thousands of Dollars)	2015	2014
Fair value of commodity trading net contract assets outstanding at Jan. 1	\$ 21,811	\$ 30,514
Contracts realized or settled during the period	(3,578)	(12,698)
Commodity trading contract additions and changes during the period	(7,193)	3,995
Fair value of commodity trading net contract assets outstanding at Dec. 31	<u>\$ 11,040</u>	<u>\$ 21,811</u>

At Dec. 31, 2015, a 10 percent increase in market prices for commodity trading contracts would increase pretax income by approximately \$0.3 million, whereas a 10 percent decrease would decrease pretax income by approximately \$0.3 million. At Dec. 31, 2014, a 10 percent increase in market prices for commodity trading contracts would increase pretax income by approximately \$0.9 million, whereas a 10 percent decrease would decrease pretax income by approximately \$0.9 million.

Xcel Energy Inc.'s utility subsidiaries' wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, including transactions that are not recorded at fair value, using an industry standard methodology known as Value at Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

The VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95 percent confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2015	\$ 0.10	\$ 3.00	\$ 0.28	\$ 1.34	\$ 0.06
2014	0.57	3.00	0.61	4.06	0.13

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 46 percent of its 2016 and approximately 16 percent of its 2017 enriched nuclear material requirements from sources that could be impacted by events in Ukraine and sanctions against Russia. Alternate potential sources are expected to provide the flexibility to manage NSP-Minnesota's nuclear fuel supply to ensure that plant availability and reliability will not be negatively impacted in the near-term. Long-term, through 2024, NSP-Minnesota is scheduled to take delivery of approximately 35 percent of its average enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. NSP-Minnesota is closely following the progression of these events and will periodically assess if further actions are required to assure a secure supply of enriched nuclear material beyond 2016.

Interest Rate Risk — Xcel Energy is subject to the risk of fluctuating interest rates in the normal course of business. Xcel Energy's risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

At Dec. 31, 2015 and 2014, a 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact annual pretax interest expense by approximately \$8.5 million and \$10.4 million, respectively. See Note 11 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

NSP-Minnesota also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At Dec. 31, 2015, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities, and other investments. These investments may be used only for activities related to nuclear decommissioning. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning. Since the accounting for nuclear decommissioning recognizes that costs are recovered through rates, fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings.

Credit Risk — Xcel Energy Inc. and its subsidiaries are also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. Xcel Energy Inc. and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At Dec. 31, 2015, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of \$1.9 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of \$6.1 million. At Dec. 31, 2014, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of \$12.2 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of \$2.7 million.

Xcel Energy Inc. and its subsidiaries conduct standard credit reviews for all counterparties. Xcel Energy employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase Xcel Energy's credit risk.

Fair Value Measurements

Xcel Energy follows accounting and disclosure guidance on fair value measurements that contains a hierarchy for inputs used in measuring fair value and requires disclosure of the observability of the inputs used in these measurements. See Note 11 to the consolidated financial statements for further discussion of the fair value hierarchy and the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2015. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are deferred as OCI or regulatory assets and liabilities. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Dec. 31, 2015.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 1.3 percent and 12.2 percent of gross assets and liabilities, respectively, measured at fair value at Dec. 31, 2015.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included \$22.7 million and \$4.6 million of estimated fair values, respectively, for FTRs held at Dec. 31, 2015.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. There were no Level 3 forwards or options held at Dec. 31, 2015.

Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of private equity investments and real estate investments. Based on an evaluation of NSP-Minnesota's ability to redeem private equity investments and real estate investment funds measured at net asset value, estimated fair values for these investments totaling \$242.3 million in the nuclear decommissioning fund at Dec. 31, 2015 (approximately 13.6 percent of total assets measured at fair value) are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a regulatory asset.

Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	2015	2014	2013
Net cash provided by operating activities	\$ 3,026	\$ 2,648	\$ 2,584

Net cash provided by operating activities increased by \$378 million for 2015 as compared to 2014. The increase was primarily due to rate increases in various jurisdictions, higher customer refunds in 2014 and income tax refunds received in 2015 compared to taxes paid in 2014, partially offset by refunds issued as part of a settlement agreement with Golden Spread and PNM in 2015.

Net cash provided by operating activities increased by \$64 million for 2014 as compared to 2013. Additional net income, excluding amounts related to non-cash operating activities (e.g. depreciation and deferred tax expenses) and lower pension contributions in 2014 were offset by changes in working capital and other noncurrent assets and liabilities.

(Millions of Dollars)	2015	2014	2013
Net cash used in investing activities	\$ (3,623)	\$ (3,117)	\$ (3,213)

Net cash used in investing activities increased by \$506 million for 2015 as compared to 2014. The increase was primarily attributable to the acquisition of two wind projects in 2015, partially offset by higher insurance proceeds related to Sherco Unit 3 received in 2015.

Net cash used in investing activities decreased by \$96 million for 2014 as compared to 2013. The decrease was primarily attributable to higher capital expenditures in 2013 associated with several major construction projects including the Monticello nuclear EPU and the PI steam generator replacement. The change in capital expenditures was partially offset by the impact of higher insurance proceeds related to Sherco Unit 3 and proceeds received from the sale of certain transmission assets to Sharyland in 2013.

(Millions of Dollars)	2015	2014	2013
Net cash provided by financing activities	\$ 602	\$ 442	\$ 654

Net cash provided by financing activities increased by \$160 million for 2015 as compared to 2014. The increase was primarily due to higher debt issuances, partially offset by repayments of short-term debt in 2015 compared to proceeds in 2014 and the impact of less common stock issuances in 2015.

Net cash provided by financing activities decreased by \$212 million for 2014 as compared to 2013. The decrease was primarily due to lower proceeds from long-term debt, less issuances of common stock and higher dividend payments, partially offset by higher proceeds from short-term debt and lower repayments of long-term debt.

See discussion of trends, commitments and uncertainties, and the potential future impact on cash flow and liquidity under Capital Sources.

Capital Requirements

Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, hybrid and other securities to maintain desired capitalization ratios.

Capital Expenditures — The actual and current estimated base capital expenditure programs of Xcel Energy Inc. and its subsidiaries for the years 2015 through 2020 are shown in the table below.

	Actual	Base Capital Forecast					
(Millions of Dollars)	2015	2016	2017	2018	2019	2020	2016 - 2020 Total
By Subsidiary							
NSP-Minnesota	\$ 1,753	\$ 1,290	\$ 1,050	\$ 1,215	\$ 1,245	\$ 1,125	\$ 5,925
PSCo.....	944	975	940	960	1,030	1,070	4,975
SPS.....	602	560	725	640	520	450	2,895
NSP-Wisconsin.....	230	225	250	295	265	285	1,320
Other.....	—	10	10	10	10	10	50
Total capital expenditures	<u>\$ 3,529</u>	<u>\$ 3,060</u>	<u>\$ 2,975</u>	<u>\$ 3,120</u>	<u>\$ 3,070</u>	<u>\$ 2,940</u>	<u>\$ 15,165</u>

	Actual	Base Capital Forecast					
(Millions of Dollars)	2015	2016	2017	2018	2019	2020	2016 - 2020 Total
By Function							
Electric transmission	\$ 889	\$ 700	\$ 825	\$ 875	\$ 855	\$ 870	\$ 4,125
Electric distribution	639	645	775	790	915	940	4,065
Electric generation	1,230	835	510	565	470	465	2,845
Natural gas	368	390	335	395	390	400	1,910
Nuclear fuel	90	120	120	60	145	85	530
Minnesota Integrated Resource Plan renewables	—	—	120	250	110	—	480
Other.....	313	370	290	185	185	180	1,210
Total capital expenditures	<u>\$ 3,529</u>	<u>\$ 3,060</u>	<u>\$ 2,975</u>	<u>\$ 3,120</u>	<u>\$ 3,070</u>	<u>\$ 2,940</u>	<u>\$ 15,165</u>

In addition, Xcel Energy has potential incremental capital investment opportunities that could increase the base capital forecast by \$2.5 billion over the 2016-2020 timeframe. The potential incremental investment opportunities include renewables from the NSP System resource plan, renewables in Colorado as part of the “Our Energy Future” plan, distribution grid modernization, natural gas reserves in Colorado and other investments. This would result in a total capital forecast of \$17.7 billion for 2016-2020.

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility capital expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margin requirements, the availability of purchased power, alternative plans for meeting long-term energy needs, compliance with environmental requirements, RPS and merger, acquisition and divestiture opportunities. The table above does not include potential expenditures of Xcel Energy’s TransCos.

Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. Xcel Energy does not anticipate issuing any equity to fund its base capital investment program for 2016-2020. The current estimated financing plans of Xcel Energy Inc. and its subsidiaries for the years 2016 through 2020 are shown in the table below.

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from Operations*	\$ 13,280
New Debt**	1,885
Equity	—
2016-2020 Capital Expenditures	<u>\$ 15,165</u>
Maturing Debt	\$ 4,165

* Net of dividend and pension funding.

** Reflects a combination of short and long-term debt.

Contractual Obligations and Other Commitments — In addition to its capital expenditure programs, Xcel Energy has contractual obligations and other commitments that will need to be funded in the future. The following is a summarized table of contractual obligations and other commercial commitments at Dec. 31, 2015. See the statements of capitalization and additional discussion in Notes 4 and 13 to the consolidated financial statements.

(Thousands of Dollars)	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	After 5 Years
Long-term debt, principal and interest payments ^(a)	\$ 21,797,721	\$ 1,227,067	\$ 2,897,756	\$ 2,547,661	\$ 15,125,237
Capital lease obligations	334,461	17,135	29,722	28,842	258,762
Operating leases ^{(b)(c)}	3,529,682	241,572	462,152	515,767	2,310,191
Unconditional purchase obligations ^(d)	8,523,291	1,801,881	2,088,242	1,220,206	3,412,962
Other long-term obligations, including current portion ^(e)	322,687	93,698	153,719	75,270	—
Payments to vendors in process	32,547	32,547	—	—	—
Short-term debt	846,000	846,000	—	—	—
Total contractual cash obligations ^{(f)(g)(h)}	<u>\$ 35,386,389</u>	<u>\$ 4,259,900</u>	<u>\$ 5,631,591</u>	<u>\$ 4,387,746</u>	<u>\$ 21,107,152</u>

- (a) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at Dec. 31, 2015, and outstanding principal for each investment with the terms ending at each instrument's maturity.
- (b) Under some leases, Xcel Energy would have to sell or purchase the property that it leases if it chose to terminate before the scheduled lease expiration date. Most of Xcel Energy's railcar, vehicle and equipment and aircraft leases have these terms. At Dec. 31, 2015, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately \$61.0 million. In addition, at the end of the equipment lease terms, each lease must be extended, equipment purchased for the greater of the fair value or unamortized value of equipment sold to a third party with Xcel Energy making up any deficiency between the sales price and the unamortized value.
- (c) Included in operating lease payments are \$217.0 million, \$418.7 million, \$469.1 million and \$2.1 billion, for the less than 1 year, 1-3 years, 3-5 years and after 5 years categories, respectively, pertaining to PPAs that were accounted for as operating leases.
- (d) Xcel Energy Inc. and its subsidiaries have contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. Additionally, the utility subsidiaries of Xcel Energy Inc. have entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. Certain contractual purchase obligations are adjusted on indices. The effects of price changes are mitigated through cost of energy adjustment mechanisms.
- (e) Other long-term obligations relate primarily to amounts associated with technology agreements and approximate investments in Energy Impact Fund LP, as well as uncertain tax positions.
- (f) Xcel Energy also has outstanding authority under O&M contracts to purchase up to approximately \$3.2 billion of goods and services through the year 2053, in addition to the amounts disclosed in this table.
- (g) In January 2016, contributions of \$125.0 million were made across four of Xcel Energy's pension plans. Obligations of this type are dependent on several factors, including management discretion, and therefore, they are not included in the table.
- (h) Xcel Energy expects to contribute approximately \$12.3 million to the postretirement health care plans during 2016. Obligations of this type are dependent on several factors, including management discretion, and therefore, they are not included in the table.

Common Stock Dividends — Future dividend levels will be dependent on Xcel Energy's results of operations, financial position, cash flows, reinvestment opportunities and other factors, and will be evaluated by the Xcel Energy Inc. Board of Directors. Xcel Energy's financial objectives include: growing annual ongoing EPS four percent to six percent, growing the annual dividend five percent to seven percent and targeting a dividend payout ratio of 60 percent to 70 percent of annual ongoing EPS. On Feb. 17, 2016, Xcel Energy announced a quarterly dividend of \$0.34 per share, which represented an increase of 6.3 percent. Xcel Energy's dividend policy balances:

- Projected cash generation;
- Projected capital investment;
- A reasonable rate of return on shareholder investment; and
- The impact on Xcel Energy's capital structure and credit ratings.

In addition, there are certain statutory limitations that could affect dividend levels. Federal law places certain limits on the ability of public utilities within a holding company system to declare dividends.

Specifically, under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The utility subsidiaries' dividends may be limited directly or indirectly by state regulatory commissions or bond indenture covenants. See Note 4 to the consolidated financial statements for further discussion of restrictions on dividend payments.

Regulation of Derivatives — In July 2010, financial reform legislation was passed that provides for the regulation of derivative transactions amongst other provisions. Provisions within the bill provide the CFTC and the SEC with expanded regulatory authority over derivative and swap transactions. The CFTC ruled that swap dealing activity conducted by entities for the preceding 12 months under a notional limit, initially set at \$8 billion, will fall under the general de minimis threshold and will not subject an entity to registering as a swap dealer. The de minimis threshold is scheduled to be reduced to \$3 billion in 2017. Xcel Energy's current and projected swap activity is well below these de minimis thresholds. The bill also contains provisions that exempt certain derivatives end users from much of the clearing and margin requirements and Xcel Energy's Board of Directors has renewed the end-user exemption on an annual basis. Xcel Energy is currently meeting all reporting requirements and transaction restrictions.

Pension Fund — Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, short-term to long-duration fixed income and interest rate swap securities, and alternative investments, including private equity, real estate, hedge funds and commodity investments.

The funded status and pension assumptions are summarized in the following tables:

(Millions of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Fair value of pension assets	\$ 2,884	\$ 3,084
Projected pension obligation ^(a)	3,568	3,747
Funded status	<u>\$ (684)</u>	<u>\$ (663)</u>

(a) Excludes nonqualified plan of \$42 million and \$47 million at Dec. 31, 2015 and 2014, respectively.

Pension Assumptions	2015	2014
Discount rate	4.66%	4.11%
Expected long-term rate of return	6.87	7.09

Capital Sources

Short-Term Funding Sources — Xcel Energy uses a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for construction expenditures, working capital and dividend payments.

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts. At Dec. 31, 2015 and 2014, there was \$3.3 million of cash held in these accounts.

Commercial Paper — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS each have individual commercial paper programs. The authorized levels for these commercial paper programs are:

- \$1 billion for Xcel Energy Inc.;
- \$700 million for PSCo;
- \$500 million for NSP-Minnesota;
- \$400 million for SPS; and
- \$150 million for NSP-Wisconsin.

Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2015
Borrowing limit	\$ 2,750
Amount outstanding at period end	846
Average amount outstanding	290
Maximum amount outstanding	846
Weighted average interest rate, computed on a daily basis	0.56%
Weighted average interest rate at end of period	0.82

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014	Year Ended Dec. 31, 2013
Borrowing limit	\$ 2,750	\$ 2,750	\$ 2,450
Amount outstanding at period end	846	1,020	759
Average amount outstanding	601	841	481
Maximum amount outstanding	1,360	1,200	1,160
Weighted average interest rate, computed on a daily basis	0.48%	0.33%	0.31%
Weighted average interest rate at end of period	0.82	0.56	0.25

Credit Facilities — NSP-Minnesota, NSP-Wisconsin, PSCo, SPS, and Xcel Energy Inc. each have five-year credit agreements with a syndicate of banks. The total size of the credit facilities is \$2.75 billion and each credit facility terminates in October 2019.

NSP-Minnesota, PSCo, SPS and Xcel Energy Inc. each have the right to request an extension of the revolving termination date for two additional one-year periods. NSP-Wisconsin has the right to request an extension of the revolving termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

As of Feb. 17, 2016, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility ^(a)	Drawn ^(b)	Available	Cash	Liquidity
Xcel Energy Inc.	\$ 1,000	\$ 616	\$ 384	\$ —	\$ 384
PSCo	700	4	696	1	697
NSP-Minnesota	500	250	250	1	251
SPS	400	65	335	1	336
NSP-Wisconsin	150	—	150	3	153
Total	<u>\$ 2,750</u>	<u>\$ 935</u>	<u>\$ 1,815</u>	<u>\$ 6</u>	<u>\$ 1,821</u>

(a) These credit facilities mature in October 2019.

(b) Includes outstanding commercial paper and letters of credit.

Money Pool — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated in consolidation.

NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions. NSP-Wisconsin does not participate in the money pool.

Registration Statements — Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of one billion shares of \$2.50 par value common stock. As of Dec. 31, 2015 and 2014, Xcel Energy Inc. had approximately 508 million shares and 506 million shares of common stock outstanding, respectively. In addition, Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of seven million shares of \$100 par value preferred stock. Xcel Energy Inc. had no shares of preferred stock outstanding on Dec. 31, 2015 and 2014.

Xcel Energy Inc. and its utility subsidiaries have registration statements on file with the SEC pursuant to which they may sell securities from time to time. These registration statements, which are uncapped, permit Xcel Energy Inc. and its utility subsidiaries to issue debt and other securities in the future at amounts, prices and with terms to be determined at the time of future offerings, and in the case of our utility subsidiaries, subject to commission approval.

Financing Plans — During 2016, Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- Xcel Energy Inc. plans to issue approximately \$700 million of senior unsecured bonds;
- NSP-Minnesota plans to issue approximately \$250 million of first mortgage bonds; and
- SPS plans to issue approximately \$350 million of first mortgage bonds.

Financing plans are subject to change, depending on capital expenditures, internal cash generation, market conditions and other factors.

Long-Term Borrowings and Other Financing Instruments — See the consolidated statements of capitalization and a discussion of the long-term borrowings in Note 4 to the consolidated financial statements.

During 2015, Xcel Energy Inc. and its utility subsidiaries completed the following bond issuances:

- PSCo issued \$250 million of 2.9 percent first mortgage bonds due May 15, 2025;
- Xcel Energy Inc. issued \$250 million of 1.2 percent senior notes due June 1, 2017 and \$250 million of 3.3 percent senior notes due June 1, 2025;
- NSP-Wisconsin issued \$100 million of 3.3 percent first mortgage bonds due June 15, 2024;
- NSP-Minnesota issued \$300 million of 2.2 percent first mortgage bonds due Aug. 15, 2020 and \$300 million of 4.0 percent first mortgage bonds due Aug. 15, 2045; and
- SPS issued \$200 million of 3.3 percent first mortgage bonds due June 15, 2024.

Xcel Energy Inc. issued approximately 5.7 million shares of common stock through an ATM program for approximately \$175 million during the first six months of 2014. Xcel Energy completed its ATM program as of June 30, 2014. Xcel Energy does not anticipate issuing any additional equity over the next five years based on its current capital expenditure plan.

Income Tax — In December 2015, the Consolidated Appropriations Act, 2016 (Act) was signed into law. The Act provides varying extensions of bonus depreciation, PTCs, ITCs, and the R&E credit. The impact of these items will vary based on the amount and timing of investment, level of production, and the amount of qualifying expenditures. See Note 6 to the consolidated financial statements for further discussion.

Off-Balance-Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements, other than those currently disclosed, that have or are reasonably likely to have a current or future effect on financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Earnings Guidance

Xcel Energy's 2016 ongoing earnings guidance is \$2.12 to \$2.27 per share. Key assumptions related to 2016 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the year.
- Weather-normalized retail electric utility sales are projected to increase approximately 0.5 percent to 1.0 percent.
- Weather normalized retail firm natural gas sales are projected to be relatively flat.
- Capital rider revenue is projected to increase by \$70 million to \$80 million over 2015 levels.
- The change in O&M expenses is projected to be within a range of 0 percent to 2 percent from 2015 levels.
- Depreciation expense is projected to increase approximately \$200 million over 2015 levels.
- Property taxes are projected to increase approximately \$40 million to \$50 million over 2015 levels.
- Interest expense (net of AFUDC — debt) is projected to increase \$40 million to \$50 million over 2015 levels.
- AFUDC — equity is projected to decline approximately \$10 million to \$15 million from 2015 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 509 million shares.

Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy expects to deliver an attractive total return to our shareholders through a combination of earnings growth and dividend yield, based on the following long-term objectives:

- Deliver long-term annual EPS growth of 4 percent to 6 percent, based on ongoing 2015 EPS of \$2.10, which was the mid-point of Xcel Energy's 2015 ongoing guidance range;
- Deliver annual dividend increases of 5 percent to 7 percent;
- Target a dividend payout ratio of 60 percent to 70 percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management's view, not reflective of ongoing operations.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

See Item 7, incorporated by reference.

Item 8 — Financial Statements and Supplementary Data

See Item 15-1 for an index of financial statements included herein.

See Note 18 to the consolidated financial statements for summarized quarterly financial data.

Management Report on Internal Controls Over Financial Reporting

The management of Xcel Energy Inc. is responsible for establishing and maintaining adequate internal control over financial reporting. Xcel Energy Inc.'s internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'s management and board of directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Xcel Energy Inc. management assessed the effectiveness of Xcel Energy Inc.'s internal control over financial reporting as of Dec. 31, 2015. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework (2013)*. Based on our assessment, we believe that, as of Dec. 31, 2015, Xcel Energy Inc.'s internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

Xcel Energy Inc.'s independent registered public accounting firm has issued an audit report on the Xcel Energy Inc.'s internal control over financial reporting. Its report appears herein.

/s/ BEN FOWKE

Ben Fowke

Chairman, President and Chief Executive Officer

Feb. 19, 2016

/s/ TERESA S. MADDEN

Teresa S. Madden

Executive Vice President, Chief Financial Officer

Feb. 19, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Xcel Energy Inc.
Minneapolis, Minnesota

We have audited the accompanying consolidated balance sheets and statements of capitalization of Xcel Energy Inc. and subsidiaries (the “Company”) as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, cash flows, and common stockholders’ equity for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company’s management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Xcel Energy Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 19, 2016 expressed an unqualified opinion on the Company’s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 19, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Xcel Energy Inc.
Minneapolis, Minnesota

We have audited the internal control over financial reporting of Xcel Energy Inc. and subsidiaries (the “Company”) as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company’s internal control over financial reporting is a process designed by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2015 of the Company and our report dated February 19, 2016 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 19, 2016

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(amounts in thousands, except per share data)

	Year Ended Dec. 31		
	2015	2014	2013
Operating revenues			
Electric	\$ 9,275,986	\$ 9,465,890	\$ 9,034,045
Natural gas	1,672,081	2,142,738	1,804,679
Other	76,419	77,507	76,198
Total operating revenues	11,024,486	11,686,135	10,914,922
Operating expenses			
Electric fuel and purchased power	3,762,953	4,210,142	4,018,672
Cost of natural gas sold and transported	904,794	1,372,479	1,082,751
Cost of sales — other	36,216	34,352	33,323
Operating and maintenance expenses	2,329,670	2,334,379	2,273,532
Conservation and demand side management program expenses	224,679	301,772	260,726
Depreciation and amortization	1,124,524	1,019,045	977,863
Taxes (other than income taxes)	511,675	465,836	420,500
Loss on Monticello life cycle management/extended power uprate project	129,463	—	—
Total operating expenses	9,023,974	9,738,005	9,067,367
Operating income	2,000,512	1,948,130	1,847,555
Other income, net	5,400	5,296	2,972
Equity earnings of unconsolidated subsidiaries	34,390	30,151	30,020
Allowance for funds used during construction — equity	55,936	89,750	87,683
Interest charges and financing costs			
Interest charges — includes other financing costs of \$24,175, \$22,986 and \$30,135, respectively	595,282	566,608	575,199
Allowance for funds used during construction — debt	(26,248)	(38,402)	(39,179)
Total interest charges and financing costs	569,034	528,206	536,020
Income before income taxes	1,527,204	1,545,121	1,432,210
Income taxes	542,719	523,815	483,976
Net income	<u>\$ 984,485</u>	<u>\$ 1,021,306</u>	<u>\$ 948,234</u>
Weighted average common shares outstanding:			
Basic	507,768	503,847	496,073
Diluted	508,168	504,117	496,532
Earnings per average common share:			
Basic	\$ 1.94	\$ 2.03	\$ 1.91
Diluted	1.94	2.03	1.91
Cash dividends declared per common share	\$ 1.28	\$ 1.20	\$ 1.11

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(amounts in thousands)

	Year Ended Dec. 31		
	2015	2014	2013
Net income	\$ 984,485	\$ 1,021,306	\$ 948,234
Other comprehensive (loss) income			
Pension and retiree medical benefits:			
Net pension and retiree medical benefit (losses) gains arising during the period, net of tax of \$(5,026), \$(4,687), and \$1,746, respectively	(7,906)	(7,517)	1,408
Amortization of losses included in net periodic benefit cost, net of tax of \$2,249, \$2,159, and \$4,151, respectively	3,526	3,495	3,306
	<u>(4,380)</u>	<u>(4,022)</u>	<u>4,714</u>
Derivative instruments:			
Net fair value (decrease) increase, net of tax of \$(46), \$(103), and \$17, respectively. . .	(70)	(163)	12
Reclassification of losses to net income, net of tax of \$1,810, \$1,493, and \$2,541, respectively	2,836	2,288	1,476
	<u>2,766</u>	<u>2,125</u>	<u>1,488</u>
Marketable securities:			
Net fair value increase, net of tax of \$0, \$21, and \$117, respectively	—	33	176
Other comprehensive (loss) income	<u>(1,614)</u>	<u>(1,864)</u>	<u>6,378</u>
Comprehensive income	<u>\$ 982,871</u>	<u>\$ 1,019,442</u>	<u>\$ 954,612</u>

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(amounts in thousands)

	Year Ended Dec. 31		
	2015	2014	2013
Operating activities			
Net income	\$ 984,485	\$ 1,021,306	\$ 948,234
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,142,966	1,036,515	1,001,843
Conservation and demand side management program amortization	5,225	6,033	6,531
Nuclear fuel amortization	106,424	114,542	98,089
Deferred income taxes	535,868	569,378	515,062
Amortization of investment tax credits	(5,277)	(5,543)	(5,753)
Allowance for equity funds used during construction	(55,936)	(89,750)	(87,683)
Equity earnings of unconsolidated subsidiaries	(34,390)	(30,151)	(30,020)
Dividends from unconsolidated subsidiaries	40,128	36,707	36,416
Provision for bad debts	36,074	42,765	37,627
Share-based compensation expense	44,928	32,189	24,613
Gain on sale of transmission assets	—	—	(13,661)
Loss on Monticello life cycle management/extended power uprate project	129,463	—	—
Net realized and unrealized hedging and derivative transactions	21,919	5,506	(4,704)
Other, net	(1,326)	—	—
Changes in operating assets and liabilities:			
Accounts receivable	65,826	(125,146)	(108,911)
Accrued unbilled revenues	73,625	(41,262)	(23,867)
Inventories	(11,240)	(20,558)	(43,588)
Other current assets	9,273	(111,300)	(18,071)
Accounts payable	(120,002)	(53,242)	132,441
Net regulatory assets and liabilities	102,465	195,823	141,325
Other current liabilities	66,134	137,147	126,555
Pension and other employee benefit obligations	(69,256)	(101,457)	(156,369)
Change in other noncurrent assets	10,553	44,364	(9,998)
Change in other noncurrent liabilities	(52,090)	(15,674)	17,925
Net cash provided by operating activities	3,025,839	2,648,192	2,584,036
Investing activities			
Utility capital/construction expenditures	(3,683,359)	(3,199,791)	(3,395,325)
Allowance for equity funds used during construction	55,936	89,750	87,683
Proceeds from sale of transmission assets	—	—	37,118
Proceeds from insurance recoveries	27,237	6,000	90,000
Purchases of investments in external decommissioning fund	(1,257,924)	(595,569)	(1,481,881)
Proceeds from the sale of investments in external decommissioning fund	1,236,873	588,430	1,461,291
Investments in WYCO Development LLC and other	(1,392)	(2,376)	(7,504)
Other, net	(145)	(3,695)	(4,766)
Net cash used in investing activities	(3,622,774)	(3,117,251)	(3,213,384)
Financing activities			
(Repayments of) proceeds from short-term borrowings, net	(173,500)	260,500	157,000
Proceeds from issuance of long-term debt	1,626,212	837,584	1,431,895
Repayments of long-term debt	(250,882)	(275,948)	(652,451)
Proceeds from issuance of common stock	7,011	180,798	231,767
Dividends paid	(606,574)	(561,411)	(514,042)
Net cash provided by financing activities	602,267	441,523	654,169
Net change in cash and cash equivalents	5,332	(27,536)	24,821
Cash and cash equivalents at beginning of period	79,608	107,144	82,323
Cash and cash equivalents at end of period	<u>\$ 84,940</u>	<u>\$ 79,608</u>	<u>\$ 107,144</u>
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	\$ (542,860)	\$ (512,602)	\$ (514,911)
Cash received (paid) for income taxes, net	58,287	(4,542)	17,188
Supplemental disclosure of non-cash investing and financing transactions:			
Property, plant and equipment additions in accounts payable	\$ 321,969	\$ 417,473	\$ 452,453
Issuance of common stock for reinvested dividends and 401(k) plans	52,911	62,078	56,950

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(amounts in thousands, except share and per share data)

	Dec. 31	
	2015	2014
Assets		
Current assets		
Cash and cash equivalents	\$ 84,940	\$ 79,608
Accounts receivable, net	724,606	826,506
Accrued unbilled revenues	654,867	728,492
Inventories	608,584	597,183
Regulatory assets	344,630	444,058
Derivative instruments	33,842	85,723
Deferred income taxes	140,219	246,210
Prepaid taxes	163,023	185,488
Prepayments and other	155,734	171,112
Total current assets	<u>2,910,445</u>	<u>3,364,380</u>
Property, plant and equipment, net	31,205,851	28,756,916
Other assets		
Nuclear decommissioning fund and other investments	1,902,995	1,832,640
Regulatory assets	2,858,741	2,774,216
Derivative instruments	51,083	53,775
Other	124,420	175,957
Total other assets	<u>4,937,239</u>	<u>4,836,588</u>
Total assets	<u>\$ 39,053,535</u>	<u>\$ 36,957,884</u>
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	\$ 657,021	\$ 257,726
Short-term debt	846,000	1,019,500
Accounts payable	960,982	1,173,006
Regulatory liabilities	306,830	410,729
Taxes accrued	438,189	396,615
Accrued interest	166,829	158,536
Dividends payable	162,410	151,720
Derivative instruments	29,839	21,632
Other	490,197	475,119
Total current liabilities	<u>4,058,297</u>	<u>4,064,583</u>
Deferred credits and other liabilities		
Deferred income taxes	6,293,661	5,852,988
Deferred investment tax credits	68,419	73,696
Regulatory liabilities	1,332,889	1,163,429
Asset retirement obligations	2,608,562	2,446,631
Derivative instruments	168,311	183,936
Customer advances	228,999	256,945
Pension and employee benefit obligations	941,002	936,907
Other	261,756	264,653
Total deferred credits and other liabilities	<u>11,903,599</u>	<u>11,179,185</u>
Commitments and contingencies		
Capitalization		
Long-term debt	12,490,719	11,499,634
Common stock — 1,000,000,000 shares authorized of \$2.50 par value; 507,535,523 and 505,733,267 shares outstanding at Dec. 31, 2015 and 2014, respectively	1,268,839	1,264,333
Additional paid in capital	5,889,106	5,837,330
Retained earnings	3,552,728	3,220,958
Accumulated other comprehensive loss	(109,753)	(108,139)
Total common stockholders' equity	<u>10,600,920</u>	<u>10,214,482</u>
Total liabilities and equity	<u>\$ 39,053,535</u>	<u>\$ 36,957,884</u>

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY
(amounts in thousands)

	Common Stock Issued			Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
	Shares	Par Value	Additional Paid In Capital			
Balance at Dec. 31, 2012	487,960	\$ 1,219,899	\$ 5,353,015	\$ 2,413,816	\$ (112,653)	\$ 8,874,077
Net income				948,234		948,234
Other comprehensive income					6,378	6,378
Dividends declared on common stock				(554,067)		(554,067)
Issuances of common stock	10,012	25,030	237,671			262,701
Share-based compensation			28,627			28,627
Balance at Dec. 31, 2013	<u>497,972</u>	<u>\$ 1,244,929</u>	<u>\$ 5,619,313</u>	<u>\$ 2,807,983</u>	<u>\$ (106,275)</u>	<u>\$ 9,565,950</u>
Net income				1,021,306		1,021,306
Other comprehensive loss					(1,864)	(1,864)
Dividends declared on common stock				(608,331)		(608,331)
Issuances of common stock	7,761	19,404	185,145			204,549
Share-based compensation			32,872			32,872
Balance at Dec. 31, 2014	<u>505,733</u>	<u>\$ 1,264,333</u>	<u>\$ 5,837,330</u>	<u>\$ 3,220,958</u>	<u>\$ (108,139)</u>	<u>\$ 10,214,482</u>
Net income				984,485		984,485
Other comprehensive loss					(1,614)	(1,614)
Dividends declared on common stock				(652,715)		(652,715)
Issuances of common stock	1,803	4,506	28,017			32,523
Share-based compensation			23,759			23,759
Balance at Dec. 31, 2015	<u>507,536</u>	<u>\$ 1,268,839</u>	<u>\$ 5,889,106</u>	<u>\$ 3,552,728</u>	<u>\$ (109,753)</u>	<u>\$ 10,600,920</u>

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
(amounts in thousands, except share and per share data)

	Dec. 31	
	2015	2014
Long-Term Debt		
NSP-Minnesota		
First Mortgage Bonds, Series due:		
Aug. 15, 2015, 1.95%	\$ —	\$ 250,000
March 1, 2018, 5.25%	500,000	500,000
Aug. 15, 2020, 2.2%	300,000	—
Aug. 15, 2022, 2.15%	300,000	300,000
May 15, 2023, 2.6%	400,000	400,000
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
July 15, 2035, 5.25%	250,000	250,000
June 1, 2036, 6.25%	400,000	400,000
July 1, 2037, 6.2%	350,000	350,000
Nov. 1, 2039, 5.35%	300,000	300,000
Aug. 15, 2040, 4.85%	250,000	250,000
Aug. 15, 2042, 3.4%	500,000	500,000
May 15, 2044, 4.125%	300,000	300,000
Aug. 15, 2045, 4.0%	300,000	—
Other	33	47
Unamortized discount	(15,911)	(11,365)
Total	4,534,122	4,188,682
Less current maturities	11	250,013
Total NSP-Minnesota long-term debt	<u>\$ 4,534,111</u>	<u>\$ 3,938,669</u>
PSCo		
First Mortgage Bonds, Series due:		
Sept. 1, 2017, 4.375% ^(a)	\$ 129,500	\$ 129,500
Aug. 1, 2018, 5.8%	300,000	300,000
June 1, 2019, 5.125%	400,000	400,000
Nov. 15, 2020, 3.2%	400,000	400,000
Sept. 15, 2022, 2.25%	300,000	300,000
March 15, 2023, 2.5%	250,000	250,000
May 15, 2025, 2.9%	250,000	—
Sept. 1, 2037, 6.25%	350,000	350,000
Aug. 1, 2038, 6.5%	300,000	300,000
Aug. 15, 2041, 4.75%	250,000	250,000
Sept. 15, 2042, 3.6%	500,000	500,000
March 15, 2043, 3.95%	250,000	250,000
March 15, 2044, 4.30%	300,000	300,000
Capital lease obligations, through 2060, 11.2% — 14.3%	164,031	172,209
Unamortized discount	(11,340)	(11,480)
Total	4,132,191	3,890,229
Less current maturities	8,103	8,178
Total PSCo long-term debt	<u>\$ 4,124,088</u>	<u>\$ 3,882,051</u>
SPS		
First Mortgage Bonds, Series due:		
June 15, 2024, 3.3%	\$ 350,000	\$ 150,000
Aug. 15, 2041, 4.5%	400,000	400,000
Unsecured Senior E Notes, due Oct. 1, 2016, 5.6%	200,000	200,000
Unsecured Senior G Notes, due Dec. 1, 2018, 8.75%	250,000	250,000
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6%	100,000	100,000
Unsecured Senior F Notes, due Oct. 1, 2036, 6%	250,000	250,000
Unamortized premium (discount)	605	(309)
Total	1,550,605	1,349,691
Less current maturities	200,000	—
Total SPS long-term debt	<u>\$ 1,350,605</u>	<u>\$ 1,349,691</u>

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION — (Continued)
(amounts in thousands, except share and per share data)

	Dec. 31	
	2015	2014
NSP-Wisconsin		
First Mortgage Bonds, Series due:		
Oct. 1, 2018, 5.25%	\$ 150,000	\$ 150,000
June 15, 2024, 3.3%	200,000	100,000
Sept. 1, 2038, 6.375%	200,000	200,000
Oct. 1, 2042, 3.7%	100,000	100,000
City of La Crosse Resource Recovery Bond, Series due Nov. 1, 2021, 6% ^(b)	18,600	18,600
Fort McCoy System Acquisition, due Oct. 15, 2030, 7%	490	523
Other	1,634	1,687
Unamortized discount	(3,131)	(2,519)
Total	667,593	568,291
Less current maturities	1,131	1,235
Total NSP-Wisconsin long-term debt	<u>\$ 666,462</u>	<u>\$ 567,056</u>
Other Subsidiaries		
Various Eloigne Co. Affordable Housing Project Notes, due 2016-2052, 0% — 8%	\$ 31,255	\$ 32,037
Total	31,255	32,037
Less current maturities	709	1,316
Total other subsidiaries long-term debt	<u>\$ 30,546</u>	<u>\$ 30,721</u>
Xcel Energy Inc.		
Unsecured Senior Notes, Series due:		
May 9, 2016, 0.75%	\$ 450,000	\$ 450,000
April 1, 2017, 5.613%	253,979	253,979
June 1, 2017, 1.2%	250,000	—
May 15, 2020, 4.7%	550,000	550,000
June 1, 2025, 3.3%	250,000	—
July 1, 2036, 6.5%	300,000	300,000
Sept. 15, 2041, 4.8%	250,000	250,000
Elimination of PSCo capital lease obligation with affiliates	(66,454)	(69,470)
Unamortized discount	(5,551)	(6,078)
Total	2,231,974	1,728,431
Less current maturities (including elimination of PSCo capital lease obligation)	447,067	(3,015)
Total Xcel Energy Inc. long-term debt	<u>\$ 1,784,907</u>	<u>\$ 1,731,446</u>
Total long-term debt	<u>\$ 12,490,719</u>	<u>\$ 11,499,634</u>
Common Stockholders' Equity		
Common stock — 1,000,000,000 shares authorized of \$2.50 par value; 507,535,523 and 505,733,267 shares outstanding at Dec. 31, 2015 and Dec. 31, 2014, respectively	\$ 1,268,839	\$ 1,264,333
Additional paid in capital	5,889,106	5,837,330
Retained earnings	3,552,728	3,220,958
Accumulated other comprehensive loss	(109,753)	(108,139)
Total common stockholders' equity	<u>\$ 10,600,920</u>	<u>\$ 10,214,482</u>

(a) Pollution control financing.

(b) Resource recovery financing.

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Business and System of Accounts — Xcel Energy Inc.'s utility subsidiaries are engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas. Xcel Energy's consolidated financial statements and disclosures are presented in accordance with GAAP. All of the utility subsidiaries' underlying accounting records also conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material respects.

Principles of Consolidation — In 2015, Xcel Energy's operations included the activity of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utility subsidiaries serve electric and natural gas customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Also included in Xcel Energy's operations are WGI, an interstate natural gas pipeline company, and WYCO, a joint venture with CIG to develop and lease natural gas pipelines, storage and compression facilities.

Xcel Energy Inc.'s nonregulated subsidiary is Eloigne, which invests in rental housing projects that qualify for low-income housing tax credits. Xcel Energy Inc. owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group, Inc., Xcel Energy International Inc., Xcel Energy Transmission Holding Company, LLC, and Xcel Energy Services Inc. Xcel Energy Inc. and its subsidiaries collectively are referred to as Xcel Energy.

Xcel Energy's consolidated financial statements include its wholly-owned subsidiaries and variable interest entities for which it is the primary beneficiary. In the consolidation process, all intercompany transactions and balances are eliminated. Xcel Energy uses the equity method of accounting for its investment in WYCO. Xcel Energy's equity earnings in WYCO are included on the consolidated statements of income as equity earnings of unconsolidated subsidiaries. Xcel Energy has investments in several plants and transmission facilities jointly owned with nonaffiliated utilities. Xcel Energy's proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets, and Xcel Energy's proportionate share of the operating costs associated with these facilities is included in its consolidated statements of income. See Note 5 for further discussion of jointly owned generation, transmission, and gas facilities and related ownership percentages.

Xcel Energy evaluates its arrangements and contracts with other entities, including but not limited to, investments, PPAs and fuel contracts to determine if the other party is a variable interest entity, if Xcel Energy has a variable interest and if Xcel Energy is the primary beneficiary. Xcel Energy follows accounting guidance for variable interest entities which requires consideration of the activities that most significantly impact an entity's financial performance and power to direct those activities, when determining whether Xcel Energy is a variable interest entity's primary beneficiary. See Note 13 for further discussion of variable interest entities.

Use of Estimates — In recording transactions and balances resulting from business operations, Xcel Energy uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. The recorded estimates are revised when better information becomes available or when actual amounts can be determined. Those revisions can affect operating results.

Regulatory Accounting — Our regulated utility subsidiaries account for certain income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or OCI, are deferred as regulatory assets based on the expected ability to recover the costs in future rates; and
- Certain credits, which would otherwise be reflected as income or OCI, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If restructuring or other changes in the regulatory environment occur, regulated utility subsidiaries may no longer be eligible to apply this accounting treatment, and may be required to eliminate regulatory assets and liabilities from their balance sheets. Such changes could have a material effect on Xcel Energy's financial condition, results of operations and cash flows. See Note 15 for further discussion of regulatory assets and liabilities.

Revenue Recognition — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is recognized. Xcel Energy presents its revenues net of any excise or other fiduciary-type taxes or fees.

NSP-Minnesota participates in MISO, and SPS participates in SPP. Xcel Energy's utility subsidiaries recognize sales to both native load and other end use customers on a gross basis. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are recorded on a gross basis in electric revenues and cost of sales. Other revenues and charges related to participating and transacting in RTOs are recorded on a net basis in cost of sales.

Xcel Energy Inc.'s utility subsidiaries have various rate-adjustment mechanisms in place that provide for the recovery of natural gas, electric fuel and purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred. When applicable, under governing regulatory commission rate orders, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

Certain rate rider mechanisms qualify for alternative revenue recognition under generally accepted accounting principles. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety, or other mandate. When certain criteria are met, revenue is recognized equal to the revenue requirement, including return on rate base items, for the qualified mechanisms. The mechanisms are revised periodically for differences between the total amount collected under the riders and the revenue recognized, which may increase or decrease the level of revenue collected from customers.

Conservation Programs — Xcel Energy Inc.'s utility subsidiaries have implemented programs in many of their retail jurisdictions to assist customers in reducing peak demand and conserving energy on the electric and natural gas systems. These programs include efficiency and redesign programs, as well as rebates for the purchase of items such as high efficiency lighting.

The costs incurred for DSM and CIP programs are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Recorded revenues for incentive programs designed for recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the annual period in which they are earned.

For PSCo, SPS and NSP-Minnesota, DSM and CIP program costs are recovered through a combination of base rate revenue and rider mechanisms. The revenue billed to customers recovers incurred costs for conservation programs and also incentive amounts that are designed to encourage Xcel Energy's achievement of energy conservation goals and compensate for related lost sales margin. For these utility subsidiaries, regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers. NSP-Wisconsin recovers approved conservation program costs in base rate revenue.

Property, Plant and Equipment and Depreciation — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned major maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property. Property, plant and equipment also includes costs associated with property held for future use. The depreciable lives of certain plant assets are reviewed annually and revised, if appropriate. Property, plant and equipment that is required to be decommissioned early by a regulator is reclassified as plant to be retired.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. See Note 12 for a discussion of the loss recognized related to the Monticello LCM/EPU project. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Xcel Energy records depreciation expense related to its plant using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 2.8, 2.7, and 2.9 percent for the years ended Dec. 31, 2015, 2014 and 2013, respectively.

Leases — Xcel Energy evaluates a variety of contracts for lease classification at inception, including PPAs and rental arrangements for office space, vehicles and equipment. Contracts determined to contain a lease because of per unit pricing that is other than fixed or market price, terms regarding the use of a particular asset, and other factors are evaluated further to determine if the arrangement is a capital lease. See Note 13 for further discussion of leases.

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in Xcel Energy's rate base for establishing utility service rates. In addition to construction-related amounts, cost of capital also is recorded to reflect returns on capital used to finance conservation programs in Minnesota.

Generally, AFUDC costs are recovered from customers as the related property is depreciated. However, in some cases commissions have approved a more current recovery of the cost of capital associated with large capital projects, resulting in a lower recognition of AFUDC. In other cases, some commissions have allowed an AFUDC calculation greater than the FERC-defined AFUDC rate, resulting in higher recognition of AFUDC.

AROs — Xcel Energy Inc.'s utility subsidiaries account for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO. Xcel Energy Inc.'s utility subsidiaries also recover through rates certain future plant removal costs in addition to AROs. The accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability. See Note 13 for further discussion of AROs.

Nuclear Decommissioning — Nuclear decommissioning studies estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants and are performed at least every three years and submitted to the MPUC and other state commissions for approval. NSP-Minnesota's most recent triennial nuclear decommissioning studies were approved by the MPUC in October 2015. These studies reflect NSP-Minnesota's plans for prompt dismantlement of the Monticello and PI facilities. These studies assume that NSP-Minnesota will store spent fuel on site pending removal to a U.S. government facility.

For rate making purposes, NSP-Minnesota recovers the total decommissioning costs related to its nuclear power plants over each facility's expected service life based on the triennial decommissioning studies filed with the MPUC and other state commissions. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds, and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. See Note 14 for further discussion of the approved nuclear decommissioning studies and funded amounts. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO as described above.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in the nuclear decommissioning fund on the consolidated balance sheets. See Note 11 for further discussion of the nuclear decommissioning fund.

Nuclear Fuel Expense — Nuclear fuel expense, which is recorded as NSP-Minnesota's nuclear generating plants use fuel, includes the cost of fuel used in the current period (including AFUDC) and costs associated with the end-of-life fuel segments.

Nuclear Refueling Outage Costs — Xcel Energy uses a deferral and amortization method for nuclear refueling O&M costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric rates.

Income Taxes — Xcel Energy accounts for income taxes using the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. Xcel Energy uses the tax rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. In making such a determination, all available evidence is considered, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax planning strategies and recent financial operations.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes, the reversal of some temporary differences are accounted for as current income tax expense. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize only applies to federal ITCs. Utility rate regulation also has resulted in the recognition of certain regulatory assets and liabilities related to income taxes, which are summarized in Note 15.

Xcel Energy follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. Xcel Energy recognizes a tax position in its consolidated financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax.

Xcel Energy reports interest and penalties related to income taxes within the other income and interest charges sections in the consolidated statements of income.

Xcel Energy Inc. and its subsidiaries file consolidated federal income tax returns as well as combined or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to Xcel Energy Inc.'s subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with combined state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries based on the relative positive tax liabilities of the subsidiaries.

See Note 6 for further discussion of income taxes.

Types of and Accounting for Derivative Instruments — Xcel Energy uses derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price, and commodity trading activities, including forward contracts, futures, swaps and options. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception, as defined by the accounting guidance for derivatives and hedging, are recorded on the consolidated balance sheets at fair value as derivative instruments. This includes certain instruments used to mitigate market risk for the utility operations including transmission in organized markets and all instruments related to the commodity trading operations. The classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues; hedging transactions for vehicle fuel costs are recorded as a component of capital projects or O&M costs; and interest rate hedging transactions are recorded as a component of interest expense. Certain utility subsidiaries are allowed to recover in electric or natural gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility. For further information on derivatives entered to mitigate commodity price risk on behalf of electric and natural gas customers, see Note 11.

Cash Flow Hedges — Certain qualifying hedging relationships are designated as a hedge of a forecasted transaction, or future cash flow (cash flow hedge). Changes in the fair value of a derivative designated as a cash flow hedge, to the extent effective, are included in OCI or deferred as a regulatory asset or liability based on recovery mechanisms until earnings are affected by the hedged transaction.

Normal Purchases and Normal Sales — Xcel Energy enters into contracts for the purchase and sale of commodities for use in its business operations. Derivatives and hedging accounting guidance requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that meet the definition of a derivative may be exempted from derivative accounting if designated as normal purchases or normal sales.

Xcel Energy evaluates all of its contracts at inception to determine if they are derivatives and if they meet the normal purchases and normal sales designation requirements. None of the contracts entered into within the commodity trading operations qualify for a normal purchases and normal sales designation.

See Note 11 for further discussion of Xcel Energy's risk management and derivative activities.

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities, whether or not settled physically, are shown on a net basis in electric operating revenues in the consolidated statements of income.

Xcel Energy's commodity trading operations are conducted by NSP-Minnesota, and PSCo. Commodity trading activities are not associated with energy produced from Xcel Energy's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms. See Note 11 for further discussion.

Fair Value Measurements — Xcel Energy presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted net asset values. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used as a primary input to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, Xcel Energy may use quoted prices for similar contracts or internally prepared valuation models to determine fair value. For the nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security. See Note 11 for further discussion.

Cash and Cash Equivalents — Xcel Energy considers investments in certain instruments, including commercial paper and money market funds, with a remaining maturity of three months or less at the time of purchase, to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. Xcel Energy establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

Inventory — All inventory is recorded at average cost.

RECs — RECs are marketable environmental instruments that represent proof that energy was generated from eligible renewable energy sources. RECs are awarded upon delivery of the associated energy and can be bought and sold. RECs are typically used as a form of measurement of compliance to RPS enacted by those states that are encouraging construction and consumption from renewable energy sources, but can also be sold separately from the energy produced. Utility subsidiaries acquire RECs from the generation or purchase of renewable power.

When RECs are purchased or acquired in the course of generation they are recorded as inventory at cost. The cost of RECs that are utilized for compliance purposes is recorded as electric fuel and purchased power expense. As a result of state regulatory orders, Xcel Energy reduces recoverable fuel costs for the cost of certain RECs and records that cost as a regulatory asset when the amount is recoverable in future rates.

Sales of RECs that are purchased or acquired in the course of generation are recorded in electric utility operating revenues on a gross basis. The cost of these RECs, related transaction costs, and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Emission Allowances — Emission allowances, including the annual SO₂ and NO_x emission allowance entitlement received from the EPA, are recorded at cost plus associated broker commission fees. Xcel Energy follows the inventory accounting model for all emission allowances. Sales of emission allowances are included in electric utility operating revenue and the operating activities section of the consolidated statements of cash flows.

Environmental Costs — Environmental costs are recorded when it is probable Xcel Energy is liable for remediation costs and the liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs, excluding inflationary increases, are recorded based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating PRPs exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for Xcel Energy's expected share of the cost. Any future costs of restoring sites where operation may extend indefinitely are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses, which may include final remediation costs. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 13 for further discussion of environmental costs.

Benefit Plans and Other Postretirement Benefits — Xcel Energy maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans under applicable accounting guidance requires management to make various assumptions and estimates.

Based on the regulatory recovery mechanisms of Xcel Energy Inc.'s utility subsidiaries, certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are recorded as regulatory assets and liabilities, rather than OCI.

See Note 9 for further discussion of benefit plans and other postretirement benefits.

Guarantees — Xcel Energy recognizes, upon issuance or modification of a guarantee, a liability for the fair market value of the obligation that has been assumed in issuing the guarantee. This liability includes consideration of specific triggering events and other conditions which may modify the ongoing obligation to perform under the guarantee.

The obligation recognized is reduced over the term of the guarantee as Xcel Energy is released from risk under the guarantee. See Note 13 for specific details of issued guarantees.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2015 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

2. Accounting Pronouncements

Recently Issued

Revenue Recognition — In May 2014, the FASB issued *Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09)*, which provides a framework for the recognition of revenue, with the objective that recognized revenues properly reflect amounts an entity is entitled to receive in exchange for goods and services. The new guidance also includes additional disclosure requirements regarding revenue, cash flows and obligations related to contracts with customers. As a result of the FASB's July 2015 deferral of the standard's required implementation date, the guidance is effective for interim and annual reporting periods beginning after Dec. 15, 2017. Xcel Energy is currently evaluating the impact of adopting ASU 2014-09 on its consolidated financial statements.

Consolidation — In February 2015, the FASB issued *Amendments to the Consolidation Analysis, Topic 810 (ASU No. 2015-02)*, which reduces the number of consolidation models and amends certain consolidation principles related to variable interest entities. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2015, and early adoption is permitted. Xcel Energy does not expect the implementation of ASU 2015-02 to have a material impact on its consolidated financial statements.

Presentation of Debt Issuance Costs — In April 2015, the FASB issued *Simplifying the Presentation of Debt Issuance Costs, Subtopic 835-30 (ASU No. 2015-03)*, which amends existing guidance to require the presentation of debt issuance costs on the balance sheet as a deduction from the carrying amount of the related debt, instead of an asset. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2015, and early adoption is permitted. Other than the prescribed reclassification of assets to an offset of debt on the consolidated balance sheets, Xcel Energy does not expect the implementation of ASU 2015-03 to have a material impact on its consolidated financial statements.

Fair Value Measurement — In May 2015, the FASB issued *Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or Its Equivalent), Topic 820 (ASU No. 2015-07)*, which removes the requirement to categorize fair value measurements using a net asset value methodology in the fair value hierarchy. This guidance will be effective on a retrospective basis, effective for interim and annual reporting periods beginning after Dec. 15, 2015, and early adoption is permitted. Other than the reduced disclosure requirements, Xcel Energy does not expect the implementation of ASU 2015-07 to have a material impact on its consolidated financial statements.

Presentation of Deferred Taxes — In November 2015, the FASB issued *Balance Sheet Classification of Deferred Taxes, Topic 740 (ASU No. 2015-17)*, which removes the requirement to present deferred tax assets and liabilities as current and noncurrent on the balance sheet based on the classification of the related asset or liability, and instead requires classification of all deferred tax assets and liabilities as noncurrent. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2016, and early adoption is permitted. Other than the prescribed classification of all deferred tax assets and liabilities as noncurrent, Xcel Energy does not expect the implementation of ASU 2015-17 to have a material impact on its consolidated financial statements.

Classification and Measurement of Financial Instruments — In January 2016, the FASB issued *Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01)*, which among other changes in accounting and disclosure requirements, replaces the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes, and also eliminates the available-for-sale classification for marketable equity securities. Under the new guidance, other than when the consolidation or equity method of accounting is utilized, changes in the fair value of equity securities are to be recognized in earnings. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2017. Xcel Energy is currently evaluating the impact of adopting ASU 2016-01 on its consolidated financial statements.

3. Selected Balance Sheet Data

(Thousands of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Accounts receivable, net		
Accounts receivable	\$ 776,494	\$ 884,225
Less allowance for bad debts	(51,888)	(57,719)
	<u>\$ 724,606</u>	<u>\$ 826,506</u>
(Thousands of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Inventories		
Materials and supplies	\$ 290,690	\$ 244,099
Fuel	202,271	183,249
Natural gas	115,623	169,835
	<u>\$ 608,584</u>	<u>\$ 597,183</u>
(Thousands of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Property, plant and equipment, net		
Electric plant	\$ 36,464,050	\$ 33,203,139
Natural gas plant	4,944,757	4,643,452
Common and other property	1,709,508	1,611,486
Plant to be retired ^(a)	38,249	71,534
CWIP	1,256,949	2,005,531
Total property, plant and equipment	44,413,513	41,535,142
Less accumulated depreciation	(13,591,259)	(13,168,418)
Nuclear fuel	2,447,251	2,347,422
Less accumulated amortization	(2,063,654)	(1,957,230)
	<u>\$ 31,205,851</u>	<u>\$ 28,756,916</u>

^(a) PSCo's Cherokee Unit 3 was retired in August 2015. In 2017, PSCo expects to both early retire Valmont Unit 5 and convert Cherokee Unit 4 from a coal-fueled generating facility to natural gas, as approved by the CPUC. Amounts are presented net of accumulated depreciation.

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. NSP-Wisconsin does not participate in the money pool. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated in consolidation.

Commercial Paper — Xcel Energy Inc. and its utility subsidiaries meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under their credit facilities. Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2015
Borrowing limit	\$ 2,750
Amount outstanding at period end	846
Average amount outstanding	290
Maximum amount outstanding	846
Weighted average interest rate, computed on a daily basis	0.56%
Weighted average interest rate at period end	0.82

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31		
	2015	2014	2013
Borrowing limit	\$ 2,750	\$ 2,750	\$ 2,450
Amount outstanding at period end	846	1,020	759
Average amount outstanding	601	841	481
Maximum amount outstanding	1,360	1,200	1,160
Weighted average interest rate, computed on a daily basis	0.48%	0.33%	0.31%
Weighted average interest rate at end of period	0.82	0.56	0.25

Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2015 and 2014, there were \$29 million and \$61 million of letters of credit outstanding, respectively, under the credit facilities. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facilities — In order to use their commercial paper programs to fulfill short-term funding needs, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available capacity under these credit facilities. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Credit Agreements — NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. each have five-year credit agreements with a syndicate of banks. The total size of the credit facilities is \$2.75 billion and each credit facility matures in October 2019.

NSP-Minnesota, PSCo, SPS, and Xcel Energy Inc. each have the right to request an extension of the termination date for two additional one-year periods. NSP-Wisconsin has the right to request an extension of the termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

Features of the credit facilities include:

- Xcel Energy Inc. may increase its credit facility by up to \$200 million, NSP-Minnesota and PSCo may each increase their credit facilities by \$100 million and SPS may increase its credit facility by \$50 million. The NSP-Wisconsin credit facility cannot be increased.
- Each credit facility has a financial covenant requiring that the debt-to-total capitalization ratio of each entity be less than or equal to 65 percent. Each entity was in compliance at Dec. 31, 2015 and 2014, respectively, as evidenced by the table below:

	Debt-to-Total Capitalization Ratio	
	2015	2014
Xcel Energy Inc.	57%	56%
NSP-Wisconsin	46	48
NSP-Minnesota	48	48
SPS	46	47
PSCo	45	47

- If Xcel Energy Inc. or any of its utility subsidiaries do not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender.
- The Xcel Energy Inc. credit facility has a cross-default provision that provides Xcel Energy Inc. will be in default on its borrowings under the facility if it or any of its subsidiaries, except NSP-Wisconsin as long as its total assets do not comprise more than 15 percent of Xcel Energy's consolidated total assets, default on certain indebtedness in an aggregate principal amount exceeding \$75 million.
- Xcel Energy Inc. and its subsidiaries were in compliance with all financial covenants in their debt agreements as of Dec. 31, 2015 and 2014.
- The interest rates under these lines of credit are based on Eurodollar borrowing margins ranging from 87.5 to 175 basis points per year based on the applicable long-term credit ratings.
- The commitment fees, also based on applicable long-term credit ratings, are calculated on the unused portion of the lines of credit at a range of 7.5 to 27.5 basis points per year.

At Dec. 31, 2015, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available:

(Millions of Dollars)	Credit Facility ^(a)	Drawn ^(b)	Available
Xcel Energy Inc.	\$ 1,000	\$ 584	\$ 416
PSCo	700	18	682
NSP-Minnesota	500	241	259
SPS	400	22	378
NSP-Wisconsin	150	10	140
Total	<u>\$ 2,750</u>	<u>\$ 875</u>	<u>\$ 1,875</u>

(a) These credit facilities mature in October 2019.

(b) Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the respective credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on the credit facilities outstanding at Dec. 31, 2015 and 2014.

Long-Term Borrowings and Other Financing Instruments

Generally, all real and personal property of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are subject to the liens of their first mortgage indentures. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses associated with refinanced debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines.

Maturities of long-term debt are as follows:

(Millions of Dollars)	
2016	\$ 657
2017	638
2018	1,206
2019	406
2020	1,257

During 2015, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- PSCo issued \$250 million of 2.9 percent first mortgage bonds due May 15, 2025;
- Xcel Energy Inc. issued \$250 million of 1.2 percent senior notes due June 1, 2017 and \$250 million of 3.3 percent senior notes due June 1, 2025;
- NSP-Wisconsin issued \$100 million of 3.3 percent first mortgage bonds due June 15, 2024;
- NSP-Minnesota issued \$300 million of 2.2 percent first mortgage bonds due Aug. 15, 2020 and \$300 million of 4.0 percent first mortgage bonds due Aug. 15, 2045; and
- SPS issued \$200 million of 3.3 percent first mortgage bonds due June 15, 2024.

During 2014, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- PSCo issued \$300 million of 4.3 percent first mortgage bonds due March 15, 2044;
- NSP-Minnesota issued \$300 million of 4.125 percent first mortgage bonds due May 15, 2044;
- SPS issued \$150 million of 3.3 percent first mortgage bonds due June 15, 2024; and
- NSP-Wisconsin issued \$100 million of 3.3 percent first mortgage bonds due June 15, 2024.

In 2014, in connection with SPS' issuance of \$150 million of 3.30 percent first mortgage bonds due June 15, 2024, SPS concurrently secured its previously issued Series G Senior Notes due Dec. 1, 2018 equally and ratably with SPS' first mortgage bonds as required pursuant to the terms of the Series G notes.

Also in 2014, to provide the required collateralization, SPS issued \$250 million of collateral 8.75 percent first mortgage bonds due Dec. 1, 2018 to the trustee under its senior unsecured indenture which secured the previously issued Series G Senior Notes, 8.75 percent due Dec. 1, 2018, equally and ratably with SPS' first mortgage bonds.

Issuances of Common Stock — During the year ended Dec. 31, 2014, Xcel Energy Inc. issued approximately 5.7 million shares of common stock through an at-the-market (ATM) program and received cash proceeds of \$172.7 million net of \$1.9 million in fees and commissions. Xcel Energy completed its ATM program as of June 30, 2014. The proceeds from the issuances of common stock were used to repay short-term debt, infuse equity into the utility subsidiaries and for other general corporate purposes.

Deferred Financing Costs — Other assets included deferred financing costs of approximately \$92 million and \$85 million, net of amortization, at Dec. 31, 2015 and 2014, respectively. Xcel Energy is amortizing these financing costs over the remaining maturity periods of the related debt.

Capital Stock — Xcel Energy Inc. has 7,000,000 shares of preferred stock authorized to be issued with a \$100 par value. At Dec. 31, 2015 and 2014, there were no shares of preferred stock outstanding.

The charters of PSCo and SPS authorize each subsidiary to issue 10,000,000 shares of preferred stock with par values of \$0.01 and \$1.00 per share, respectively. At Dec. 31, 2015 and 2014, there were no preferred shares of subsidiaries outstanding.

Xcel Energy Inc. has 1,000,000,000 shares of common stock authorized to be issued with a \$2.50 par value. Outstanding shares at Dec. 31, 2015 and 2014 were 507,535,523 and 505,733,267, respectively.

Dividend and Other Capital-Related Restrictions — Xcel Energy depends on its subsidiaries to pay dividends. All of Xcel Energy Inc.'s utility subsidiaries' dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only. Due to certain restrictive covenants, Xcel Energy Inc. is required to be current on particular interest payments before dividends can be paid.

The most restrictive dividend limitations for NSP-Minnesota, NSP-Wisconsin and SPS are imposed by their respective state regulatory commission. PSCo's dividends are subject to the FERC's jurisdiction under the Federal Power Act, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only.

Only NSP-Minnesota has a first mortgage indenture which places certain restrictions on the amount of cash dividends it can pay to Xcel Energy Inc., the holder of its common stock. Even with this restriction, NSP-Minnesota could have paid more than \$1.7 billion and \$1.6 billion in additional cash dividends to Xcel Energy Inc. at Dec. 31, 2015 and 2014, respectively.

NSP-Minnesota's state regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay by requiring an equity-to-total capitalization ratio between 46.9 percent and 57.3 percent. NSP-Minnesota's equity-to-total capitalization ratio was 52.1 percent at Dec. 31, 2015 and \$967 million in retained earnings was not restricted. Total capitalization for NSP-Minnesota was \$9.9 billion at Dec. 31, 2015, which did not exceed the limit of \$10.5 billion.

NSP-Wisconsin cannot pay annual dividends in excess of approximately \$33.3 million if its calendar year average equity-to-total capitalization ratio is or falls below the state commission authorized level of 52.5 percent, as calculated consistent with PSCW requirements. NSP-Wisconsin's calendar year average equity-to-total capitalization ratio calculated on this basis was 52.6 percent at Dec. 31, 2015 and \$2.4 million in retained earnings was not restricted.

SPS' state regulatory commissions indirectly limit the amount of dividends that SPS can pay Xcel Energy Inc. by requiring an equity-to-total capitalization ratio (excluding short-term debt) between 45.0 percent and 55.0 percent. In addition, SPS may not pay a dividend that would cause it to lose its investment grade bond rating. SPS' equity-to-total capitalization ratio (excluding short-term debt) was 53.8 percent at Dec. 31, 2015 and \$438 million in retained earnings was not restricted.

The issuance of securities by Xcel Energy Inc. generally is not subject to regulatory approval. However, utility financings and certain intra-system financings are subject to the jurisdiction of the applicable state regulatory commissions and/or the FERC. As of Dec. 31, 2015:

- PSCo has authorization to issue up to an additional \$450 million of long-term debt and up to \$800 million of short-term debt.
- SPS has authorization to issue up to \$100 million of long-term debt and \$500 million of short-term debt.
- NSP-Wisconsin has authorization to issue up to \$150 million of short-term debt and NSPW will file for additional long-term debt authorization.
- NSP-Minnesota has authorization to issue long-term securities provided the equity-to-total capitalization ratio remains between 46.9 percent and 57.3 percent and to issue short-term debt provided it does not exceed 15 percent of total capitalization. Total capitalization for NSP-Minnesota cannot exceed \$10.5 billion.

Xcel Energy believes these authorizations are adequate and seeks additional authorization as necessary.

5. Joint Ownership of Generation, Transmission and Gas Facilities

Following are the investments by Xcel Energy Inc.'s utility subsidiaries in jointly owned generation, transmission and gas facilities and the related ownership percentages as of Dec. 31, 2015:

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %
NSP-Minnesota				
Electric Generation:				
Sherco Unit 3	\$ 590,048	\$ 386,675	\$ 4,984	59%
Sherco Common Facilities Units 1, 2 and 3	145,825	93,583	47	80
Sherco Substation.	4,790	3,054	—	59
Electric Transmission:				
Grand Meadow Line and Substation	9,248	1,451	—	50
CapX2020 Transmission	947,674	107,985	68,834	51
Total NSP-Minnesota	<u>\$ 1,697,585</u>	<u>\$ 592,748</u>	<u>\$ 73,865</u>	
NSP-Wisconsin				
Electric Transmission:				
CapX2020 Transmission	\$ 154,394	\$ 6,863	\$ 1,633	80%
La Crosse, Wis. to Madison, Wis.	—	—	18,894	37
Total NSP-Wisconsin	<u>\$ 154,394</u>	<u>\$ 6,863</u>	<u>\$ 20,527</u>	
PSCo				
Electric Generation:				
Hayden Unit 1	\$ 155,159	\$ 69,679	\$ 147	76%
Hayden Unit 2	121,486	61,780	20,840	37
Hayden Common Facilities	37,756	17,910	321	53
Craig Units 1 and 2	60,158	36,570	8,518	10
Craig Common Facilities 1, 2 and 3	37,418	18,520	505	7
Comanche Unit 3	892,340	95,029	452	67
Comanche Common Facilities.	23,826	1,430	894	82
Electric Transmission:				
Transmission and other facilities, including substations	152,460	62,324	5,378	Various
Gas Transportation:				
Rifle, Colo. to Avon, Colo.	19,928	7,165	—	60
Gas Transportation Compressor.	8,353	124	127	50
Total PSCo	<u>\$ 1,508,884</u>	<u>\$ 370,531</u>	<u>\$ 37,182</u>	

NSP-Minnesota and PSCo have approximately 517 MW and 820 MW of jointly owned generating capacity, respectively. Each Company's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for providing its own financing.

6. Income Taxes

Consolidated Appropriations Act, 2016 - In December 2015, the Consolidated Appropriations Act, 2016 (Act) was signed into law. The Act provides for the following:

- Immediate expensing, or "bonus depreciation," of 50 percent for property placed in service in 2015, 2016, and 2017; 40 percent for property placed in service in 2018; and 30 percent for property placed in service in 2019. Additionally, some longer production period property placed in service in 2020 will be eligible for bonus depreciation;
- PTCs at 100 percent of the credit rate (\$0.023 per KWh) for wind energy projects that begin construction by the end of 2016; 80 percent of the credit rate for projects that begin construction in 2017; 60 percent of the credit rate for projects that begin construction in 2018; and 40 percent of the credit rate for projects that begin construction in 2019. The wind energy PTC was not extended for projects that begin construction after 2019;

- ITCs at 30 percent for commercial solar projects that begin construction by the end of 2019; 26 percent for projects that begin construction in 2020; 22 percent for projects that begin construction in 2021; and 10 percent for projects thereafter;
- R&E credit was permanently extended; and
- Delay of two years (until 2020) of the excise tax on certain employer-provided health insurance plans.

The accounting related to the Act was recorded beginning in the fourth quarter of 2015 because a change in tax law is accounted for beginning in the period of enactment. The fourth quarter 2015 accounting impacts included:

- Recognition of additional tax deductions for bonus depreciation of \$1.2 billion, and as a result, recognition of \$4.9 million benefit related to a carryback claim (see additional discussion below) and \$3.5 million expense related to valuation allowances and expirations of charitable contribution carryforwards; and
- Recognition of \$6.8 million benefit for federal R&E credits.

Tax Increase Prevention Act of 2014 — In 2014, the Tax Increase Prevention Act (TIPA) was signed into law. The TIPA provides for the following:

- The R&E credit was extended for 2014;
- PTCs were extended for projects that began construction before the end of 2014 with certain projects qualifying into future years; and
- 50 percent bonus depreciation was extended one year through 2014. Additionally, some longer production period property placed in service in 2015 is also eligible for 50 percent bonus depreciation.

The accounting related to the TIPA was recorded beginning in the fourth quarter of 2014 because a change in tax law is accounted for in the period of enactment.

American Taxpayer Relief Act of 2012 — In 2013, the American Taxpayer Relief Act (ATRA) was signed into law. The ATRA provided for the following:

- The top tax rate for dividends increased from 15 percent to 20 percent. The 20 percent dividend rate is now consistent with the tax rates for capital gains;
- The R&E credit was extended for 2012 and 2013;
- PTCs were extended for projects that began construction before the end of 2013 with certain projects qualifying into future years; and
- 50 percent bonus depreciation was extended one year through 2013. Additionally, some longer production period property placed in service in 2014 is also eligible for 50 percent bonus depreciation.

The accounting related to the ATRA, including the provisions related to 2012, was recorded beginning in the first quarter of 2013 because a change in tax law is accounted for in the period of enactment.

Federal Tax Loss Carryback Claims — In 2012, 2013, 2014 and 2015, Xcel Energy identified certain expenses related to 2009, 2010, 2011, 2013, 2014 and 2015 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a tax benefit of approximately \$5 million in 2015, \$17 million in 2014 and \$12 million in 2013 and \$15 million in 2012.

Federal Audit — Xcel Energy files a consolidated federal income tax return. In the third quarter of 2012, the IRS commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. As of Dec. 31, 2015, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in \$14 million of income tax expense for the 2009 through 2011 and 2013 claims, the recently filed 2014 claim, and the anticipated claim for 2015. In the fourth quarter of 2015, the IRS forwarded the issue to the Office of Appeals (Appeals); however the outcome and timing of a resolution is uncertain. The statute of limitations applicable to Xcel Energy's 2009 through 2011 federal income tax returns expires in December 2016 following an extension to allow additional time for the Appeals process. In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. As of Dec. 31, 2015, the IRS had not proposed any material adjustments to tax years 2012 and 2013.

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns. As of Dec. 31, 2015, Xcel Energy's earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions were as follows:

State	Year
Colorado	2009
Minnesota	2009
Texas	2009
Wisconsin	2011

As of Dec. 31, 2015, there were no state income tax audits in progress.

Unrecognized Tax Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment of cash to the taxing authority to an earlier period.

A reconciliation of the amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Unrecognized tax benefit — Permanent tax positions	\$ 25.8	\$ 16.2
Unrecognized tax benefit — Temporary tax positions	94.9	50.3
Total unrecognized tax benefit	<u>\$ 120.7</u>	<u>\$ 66.5</u>

A reconciliation of the beginning and ending amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	2015	2014	2013
Balance at Jan. 1	\$ 66.5	\$ 41.2	\$ 34.5
Additions based on tax positions related to the current year	27.1	28.7	15.1
Reductions based on tax positions related to the current year	(4.5)	(2.0)	(0.4)
Additions for tax positions of prior years	34.8	16.0	21.6
Reductions for tax positions of prior years	(2.9)	(6.0)	(4.8)
Settlements with taxing authorities	(0.3)	(9.6)	(24.8)
Lapse of applicable statutes of limitations	—	(1.8)	—
Balance at Dec. 31	<u>\$ 120.7</u>	<u>\$ 66.5</u>	<u>\$ 41.2</u>

The unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	Dec. 31, 2015	Dec. 31, 2014
NOL and tax credit carryforwards	\$ (36.7)	\$ (28.5)

It is reasonably possible that Xcel Energy's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals and audit progress and state audits resume. As the IRS Appeals and audit progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately \$58 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at Dec. 31, 2015, 2014 and 2013 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2015, 2014 or 2013.

Other Income Tax Matters — NOL amounts represent the amount of the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2015	2014
Federal NOL carryforward	\$ 2,153	\$ 1,349
Federal tax credit carryforwards	360	327
State NOL carryforwards	2,124	1,722
Valuation allowances for state NOL carryforwards	(65)	(53)
State tax credit carryforwards, net of federal detriment ^(a)	45	19
Valuation allowances for state credit carryforwards, net of federal benefit ^(b)	(24)	—

(a) State tax credit carryforwards are net of federal detriment of \$24 million and \$10 million as of Dec. 31, 2015 and 2014, respectively.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of \$13 million as of Dec. 31, 2015.

The federal carryforward periods expire between 2021 and 2035. The state carryforward periods expire between 2016 and 2035.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The following reconciles such differences for the years ending Dec. 31:

	2015	2014	2013
Federal statutory rate	35.0%	35.0%	35.0%
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	4.1	4.0	4.1
Change in unrecognized tax benefits	0.6	0.2	0.6
NOL carryback	(0.3)	(0.9)	(0.8)
Regulatory differences — utility plant items	(1.0)	(1.3)	(1.6)
Tax credits recognized, net of federal income tax expense	(2.7)	(2.6)	(2.6)
Other, net	(0.2)	(0.5)	(0.9)
Effective income tax rate	<u>35.5%</u>	<u>33.9%</u>	<u>33.8%</u>

The components of Xcel Energy's income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2015	2014	2013
Current federal tax (benefit)	\$ (36,129)	\$ (73,160)	\$ (46,173)
Current state tax expense	2,324	9,225	7,678
Current change in unrecognized tax expense	45,933	23,915	13,162
Deferred federal tax expense	480,078	505,236	439,085
Deferred state tax expense	92,132	84,787	80,907
Deferred change in unrecognized tax (benefit)	(36,342)	(20,645)	(4,930)
Deferred investment tax credits	(5,277)	(5,543)	(5,753)
Total income tax expense	<u>\$ 542,719</u>	<u>\$ 523,815</u>	<u>\$ 483,976</u>

The components of deferred income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2015	2014	2013
Deferred tax expense excluding items below	\$ 546,664	\$ 616,934	\$ 588,053
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(11,810)	(48,674)	(64,420)
Tax benefit (expense) allocated to OCI	1,013	1,117	(8,572)
Other	1	1	1
Deferred tax expense	<u>\$ 535,868</u>	<u>\$ 569,378</u>	<u>\$ 515,062</u>

The components of Xcel Energy's net deferred tax liability (current and noncurrent) at Dec. 31 were as follows:

(Thousands of Dollars)	2015	2014
Deferred tax liabilities:		
Differences between book and tax bases of property	\$ 7,119,023	\$ 6,257,191
Regulatory assets	313,414	300,762
Other	243,690	300,251
Total deferred tax liabilities	<u>\$ 7,676,127</u>	<u>\$ 6,858,204</u>
Deferred tax assets:		
NOL carryforward	\$ 851,242	\$ 552,274
Tax credit carryforward	404,738	346,064
Unbilled revenue - fuel costs	57,220	55,021
Rate refund	50,441	93,956
Regulatory liabilities	41,541	49,712
Environmental remediation	38,663	42,716
Deferred investment tax credits	29,650	31,886
NOL and tax credit valuation allowances	(27,679)	(3,402)
Other	76,869	83,199
Total deferred tax assets	<u>\$ 1,522,685</u>	<u>\$ 1,251,426</u>
Net deferred tax liability	<u><u>\$ 6,153,442</u></u>	<u><u>\$ 5,606,778</u></u>

7. Earnings Per Share

Basic EPS was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated using the treasury stock method.

Common Stock Equivalents — Xcel Energy Inc. currently has common stock equivalents related to certain equity awards in share-based compensation arrangements.

Common stock equivalents causing a dilutive impact to EPS include commitments to issue common stock related to time based equity compensation awards and time based employer matching contributions to certain 401(k) plan participants. In October 2013, Xcel Energy determined that it would settle 401(k) employer matching contributions in cash instead of common stock going forward for most of its employees. Share-based compensation accounting for the impacted employee groups ceased in October 2013, and corresponding expense amounts recorded to equity were reclassified to a liability for expected cash settlements. Following the effective date of a new PSCo bargaining agreement in August 2015, 401(k) matching contributions will be settled in cash for all Xcel Energy employee groups.

Stock equivalent units granted to Xcel Energy Inc.'s Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these awards. Restricted stock, granted to settle amounts due to certain employees under the Xcel Energy Inc. Executive Annual Incentive Award Plan, is included in common shares outstanding when granted.

Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- Equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions for settlement have been satisfied by the end of the reporting period.
- Liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

The dilutive impact of common stock equivalents affecting EPS was as follows:

(Amounts in thousands, except per share data)	2015			2014			2013		
	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	\$ 984,485			\$ 1,021,306			\$ 948,234		
Basic EPS:									
Earnings available to common shareholders	984,485	507,768	\$ 1.94	1,021,306	503,847	\$ 2.03	948,234	496,073	\$ 1.91
Effect of dilutive securities:									
Equity awards	—	400		—	270		—	459	
Diluted EPS:									
Earnings available to common shareholders	\$ 984,485	508,168	\$ 1.94	\$ 1,021,306	504,117	\$ 2.03	\$ 948,234	496,532	\$ 1.91

Dividend Reinvestment and Stock Purchase Plan and Stock Compensation Settlements — In October 2015, the Xcel Energy Inc. Board of Directors authorized open market purchases by the plan administrator as the source of shares for the dividend reinvestment program as well as market purchases of up to 3.0 million shares for stock compensation plan settlements.

8. Share-Based Compensation

Restricted Stock — Certain employees may elect to receive shares of common or restricted stock under the Xcel Energy Inc. Executive Annual Incentive Award Plan. Restricted stock is treated as an equity award and vests and settles in equal annual installments over a three-year period. Xcel Energy Inc. reinvests dividends on the restricted stock while restrictions are in place. Restrictions also apply to the additional shares of restricted stock acquired through dividend reinvestment. If the restricted shares are forfeited, the employee is not entitled to the dividends on those shares. Restricted stock has a fair value equal to the market trading price of Xcel Energy Inc.'s stock at the grant date.

Xcel Energy Inc. granted shares of restricted stock for the years ended Dec. 31 as follows:

(Shares in Thousands)	2015	2014	2013
Granted shares	42	46	33
Grant date fair value	\$ 35.00	\$ 29.69	\$ 28.30

A summary of the changes of nonvested restricted stock for the year ended 2015 were as follows:

(Shares in Thousands)	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2015	82	\$ 29.00
Granted	42	35.00
Forfeited	(9)	28.24
Vested	(35)	28.30
Dividend equivalents	3	35.19
Nonvested restricted stock at Dec. 31, 2015	83	32.62

Other Equity Awards — Xcel Energy Inc.'s Board of Directors has granted equity awards under the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated in 2010) and the 2015 Omnibus Incentive Plan (effective May 20, 2015). These plans allow the attachment of various vesting conditions and performance goals to the awards granted. The vesting conditions and performance goals may vary by plan year. At the end of the restricted period, such grants will be awarded if the vesting conditions and/or performance goals are met.

Commencing in 2014, certain employees were granted bundled equity awards with one portion of shares subject only to service conditions, and the other portion subject to performance conditions. Inclusive of other grants of time-based awards, a total of 0.3 million, 0.4 million, and 0.2 million time-based equity shares subject only to service conditions were granted in 2015, 2014, and 2013, respectively. Other than shares associated with these time-based awards, restricted stock and certain 401(k) employer match settlements, payout of all other employee equity awards and the lapsing of restrictions on the transfer of units are based on the achievement of performance criteria.

The performance conditions for a portion of the awards granted in 2015 and 2014 are based on relative TSR, measured identically to TSR liability awards granted in those years, and measurement of performance for a portion of units awarded from 2011 to 2013 is based on EPS growth with an additional condition that Xcel Energy Inc.'s annual dividend paid on its common stock remains at a specified amount per share or greater. The performance conditions for the remaining employee equity awards are based on environmental goals. Equity awards with performance conditions awarded from 2011 to 2015, plus associated dividend equivalents, will be settled or forfeited and the restricted period will lapse after three years, with potential payouts ranging from zero to 150 percent for 2011 to 2013 grants, and zero to 200 percent for 2014 and 2015 grants, depending on the level of achievement.

- The 2010 environmental awards met their targets as of Dec. 31, 2012 and were settled in shares in February 2013.
- The 2011 awards measured on EPS growth and the 2011 environmental awards met their targets as of Dec. 31, 2013 and were settled in shares in February 2014.
- The 2012 awards measured on EPS growth and the 2012 environmental awards met their targets as of Dec. 31, 2014, and were settled in shares in February 2015.
- The 2013 awards measured on EPS growth, the 2013 environmental awards and the 2013 time-based awards met their targets as of Dec. 31, 2015, and will be settled in shares in February 2016.

Equity award units granted to employees, excluding restricted stock and applicable 401(k) employer match settlements, for the years ended Dec. 31 were as follows:

(Units in Thousands)	2015	2014	2013
Granted units	496	588	774
Weighted average grant date fair value	\$ 36.09	\$ 29.90	\$ 27.65

Approximately 0.8 million of these units vested during 2015 at a total fair value of \$27.1 million. Approximately 0.5 million of these units vested during 2014 at a total fair value of \$19.6 million. Approximately 0.6 million of these units vested during 2013 at a total fair value of \$16.8 million.

A summary of the changes in the nonvested portion of these equity award units for the year ended 2015, were as follows:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested Units at Jan. 1, 2015	1,322	\$ 28.63
Granted	496	36.09
Forfeited	(99)	30.97
Vested	(756)	27.67
Dividend equivalents	62	30.25
Nonvested Units at Dec. 31, 2015	1,025	32.81

The total fair value of these nonvested equity awards as of Dec. 31, 2015 was \$36.8 million and the weighted average remaining contractual life was 1.7 years.

Stock Equivalent Units — Non-employee members of the Xcel Energy Inc. Board of Directors receive annual awards of stock equivalent units, with each unit having a value equal to one share of Xcel Energy Inc. common stock. The annual grants are vested as of the date of each member's election to the Board of Directors; there is no further service or other condition attached to the annual grants. Additionally, directors may elect to receive their fees in stock equivalent units in lieu of cash. Dividends on Xcel Energy Inc.'s common stock are converted to stock equivalent units and granted based on the number of stock equivalent units held by each participant as of the dividend date. The stock equivalent units are payable as a distribution of Xcel Energy Inc.'s common stock upon a director's termination of service.

The stock equivalent units granted for the years ended Dec. 31 were as follows:

(Units in Thousands)	2015	2014	2013
Granted units	60	62	69
Grant date fair value	\$ 34.58	\$ 30.57	\$ 29.52

A summary of the stock equivalent unit changes for the year ended 2015 are as follows:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2015	690	\$ 24.03
Granted	60	34.58
Units distributed	(29)	20.71
Dividend equivalents	25	35.26
Stock equivalent units at Dec. 31, 2015	746	25.38

TSR Liability Awards — Xcel Energy Inc.'s Board of Directors has granted TSR liability awards under the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective in 2010). The plan allows Xcel Energy to attach various performance goals to the awards granted. The liability awards granted have been historically dependent on a single measure of performance, Xcel Energy Inc.'s relative TSR measured over a three-year period. For 2015, 2014 and 2013 awards, Xcel Energy Inc.'s TSR is compared to the TSR of other companies in a 23-member utilities peer group. At the end of the three-year period, potential payouts of the awards range from zero to 200 percent, depending on Xcel Energy Inc.'s TSR compared to the applicable peer group or index.

The TSR liability awards granted for the years ended Dec. 31 were as follows:

(In Thousands)	2015	2014	2013
Awards granted	224	270	215

The total amounts of TSR liability awards settled during the years ended Dec. 31 were as follows:

(In Thousands)	2015	2014	2013
Awards settled	—	—	108
Settlement amount (cash and common stock)	\$ —	\$ —	\$ 3,057

The amount of cash used to settle Xcel Energy's TSR liability awards was \$1.5 million in 2013.

Share-Based Compensation Expense — Other than for restricted stock and certain 401(k) employer match settlements, the vesting of employee equity awards is generally predicated on the achievement of a performance condition, which is the achievement of a TSR, EPS or environmental measures target. Additionally, approximately 0.3 million, 0.4 million, and 0.2 million of equity awards were granted in 2015, 2014, and 2013, respectively, with vesting subject only to service conditions for periods up to five years. Generally, all of these instruments are considered to be equity awards since the plan settlement determination (shares or cash) resides with Xcel Energy and not the participants. In addition, these awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement. The grant date fair value of equity awards is expensed over the service period as employees vest in their rights to those awards.

The TSR liability awards have been historically settled partially in cash, and therefore do not qualify as equity awards, but rather are accounted for as liabilities. As liability awards, the fair value on which ratable expense is based, as employees vest in their rights to those awards, is remeasured each period based on the current stock price and performance achievement, and final expense is based on the market value of the shares on the date the award is settled.

The compensation costs related to share-based awards for the years ended Dec. 31 were as follows:

(Thousands of Dollars)	2015	2014	2013
Compensation cost for share-based awards ^{(a) (b)}	\$ 44,928	\$ 32,189	\$ 24,613
Tax benefit recognized in income	17,570	12,557	9,571
Capitalized compensation cost for share-based awards ^(c)	—	1,887	1,698

^(a) Compensation costs for share-based payment arrangements are included in O&M expense in the consolidated statements of income.

^(b) Included in compensation cost for share-based awards are matching contributions related to the Xcel Energy 401(k) plan, which totaled \$7.4 million, and \$7.0 million for the years ended 2014 and 2013, respectively. In October 2013, Xcel Energy determined that it would settle the 401(k) employer match in cash instead of common stock going forward for all employee groups except PSCo bargaining employees. Share-based compensation accounting for the impacted employee groups ceased in October 2013, and corresponding expense amounts recorded to equity were reclassified to a liability for expected cash settlements. In August 2015, consistent with a new PSCo bargaining agreement, share-based compensation accounting ceased for the employer 401(k) match for PSCo bargaining employees, which will be paid in cash. As a result, 2015 compensation cost for share-based awards includes no 401(k) matching contributions.

^(c) An allocated amount of the 401(k) match is capitalized.

The maximum aggregate number of shares of common stock available for issuance under the Xcel Energy Inc. 2015 Omnibus Incentive Plan (effective May 20, 2015) is 7.0 million shares. The maximum aggregate number of shares of common stock available for issuance under the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) is 8.3 million shares. Under the Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010), the total number of shares approved for issuance is 1.2 million shares.

As of Dec. 31, 2015 and 2014, there was approximately \$36.4 million and \$27.8 million, respectively, of total unrecognized compensation cost related to nonvested share-based compensation awards. Xcel Energy expects to recognize the amount unrecognized at Dec. 31, 2015 over a weighted average period of 1.7 years.

9. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its employees. Approximately 47 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2015:

- NSP-Minnesota had 1,983 and NSP-Wisconsin had 400 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2016. NSP-Minnesota also had an additional 265 nuclear operation bargaining employees covered under several collective-bargaining agreements. Some of these agreements expired in 2015, but were extended to 2016. The remaining agreements expire in 2016 and 2018.
- PSCo had 2,024 bargaining employees covered under a collective-bargaining agreement, which expires in May 2017.
- SPS had 842 bargaining employees covered under a collective-bargaining agreement, which expired in October 2014. While collective bargaining is ongoing, the terms and conditions of the expired agreement are automatically extended until the parties reach an agreement or a decision is rendered by an arbitrator.

The plans invest in various instruments which are disclosed under the accounting guidance for fair value measurements which establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring fair value. The three levels in the hierarchy and examples of each level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets as of the reporting date. The types of assets included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets included in Level 3 are those with inputs requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

Insurance contracts — Insurance contract fair values take into consideration the value of the investments in separate accounts of the insurer, which are priced based on observable inputs.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. Preferred stock is valued using recent trades and quoted prices of similar securities. The fair values for commingled funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per share market value. The investments in commingled funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on the plan's evaluation of its ability to redeem private equity and real estate investments, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Derivative Instruments — Fair values for foreign currency derivatives are determined using pricing models based on the prevailing forward exchange rate of the underlying currencies. The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Pension Benefits

Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service, the employee's average pay and, in some cases, social security benefits. Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement plan (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides unfunded, nonqualified benefits for compensation that is in excess of the limits applicable to the qualified pension plans. The total obligations of the SERP and nonqualified plan as of Dec. 31, 2015 and 2014 were \$41.8 million and \$46.5 million, respectively. In 2015 and 2014, Xcel Energy recognized net benefit cost for financial reporting for the SERP and nonqualified plans of \$9.5 million and \$4.7 million, respectively. Benefits for these unfunded plans are paid out of Xcel Energy's consolidated operating cash flows.

Xcel Energy bases the investment-return assumption on expected long-term performance for each of the investment types included in its pension asset portfolio. Xcel Energy considers the historical returns achieved by its asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. Xcel Energy continually reviews its pension assumptions. The pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2015 were below the assumed level of 7.09 percent;
- Investment returns in 2014 were above the assumed level of 7.05 percent;
- Investment returns in 2013 were below the assumed level of 6.88 percent; and
- In 2016, Xcel Energy's expected investment return assumption is 6.87 percent.

The assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by pension assets in any year.

The following table presents the target pension asset allocations for Xcel Energy at Dec. 31 for the upcoming year:

	2015	2014
Domestic and international equity securities	39%	37%
Long-duration fixed income and interest rate swap securities	27	27
Short-to-intermediate fixed income securities	13	13
Alternative investments	19	21
Cash	2	2
Total	100%	100%

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios. The aggregate projected asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

Pension Plan Assets

The following tables present, for each of the fair value hierarchy levels, Xcel Energy's pension plan assets that are measured at fair value as of Dec. 31, 2015 and 2014:

(Thousands of Dollars)	Dec. 31, 2015			
	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ 178,884	\$ —	\$ —	\$ 178,884
Derivatives	—	2,850	—	2,850
Government securities	—	412,932	—	412,932
Corporate bonds	—	248,439	—	248,439
Asset-backed securities	—	2,446	—	2,446
Common stock	93,831	—	—	93,831
Private equity investments	—	—	126,396	126,396
Commingled funds	—	1,759,066	—	1,759,066
Real estate	—	—	55,935	55,935
Other	—	3,001	—	3,001
Total	<u>\$ 272,715</u>	<u>\$ 2,428,734</u>	<u>\$ 182,331</u>	<u>\$ 2,883,780</u>

(Thousands of Dollars)	Dec. 31, 2014			
	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ 193,141	\$ —	\$ —	\$ 193,141
Derivatives	—	1,590	—	1,590
Government securities	—	439,186	—	439,186
Corporate bonds	—	318,161	—	318,161
Asset-backed securities	—	3,759	—	3,759
Mortgage-backed securities	—	11,047	—	11,047
Common stock	102,667	—	—	102,667
Private equity investments	—	—	151,871	151,871
Commingled funds	—	1,826,420	—	1,826,420
Real estate	—	—	54,657	54,657
Securities lending collateral obligation and other	—	(18,728)	—	(18,728)
Total	<u>\$ 295,808</u>	<u>\$ 2,581,435</u>	<u>\$ 206,528</u>	<u>\$ 3,083,771</u>

The following tables present the changes in Xcel Energy's Level 3 pension plan assets for the years ended Dec. 31, 2015, 2014 and 2013:

(Thousands of Dollars)	Jan. 1, 2015	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3	Dec. 31, 2015
Private equity investments	\$ 151,871	\$ 28,094	\$ (40,848)	\$ (12,721)	\$ —	\$ 126,396
Real estate	54,657	7,083	(8,443)	2,638	—	55,935
Total	<u>\$ 206,528</u>	<u>\$ 35,177</u>	<u>\$ (49,291)</u>	<u>\$ (10,083)</u>	<u>\$ —</u>	<u>\$ 182,331</u>

(Thousands of Dollars)	Jan. 1, 2014	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3	Dec. 31, 2014
Private equity investments	\$ 152,849	\$ 25,694	\$ (17,573)	\$ (9,099)	\$ —	\$ 151,871
Real estate	47,553	3,569	(2,443)	5,978	—	54,657
Total	<u>\$ 200,402</u>	<u>\$ 29,263</u>	<u>\$ (20,016)</u>	<u>\$ (3,121)</u>	<u>\$ —</u>	<u>\$ 206,528</u>

(Thousands of Dollars)	Jan. 1, 2013	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3 ^(a)	Dec. 31, 2013
Asset-backed securities	\$ 14,639	\$ —	\$ —	\$ —	\$ (14,639)	\$ —
Mortgage-backed securities	39,904	—	—	—	(39,904)	—
Private equity investments	158,498	22,058	(24,335)	(3,372)	—	152,849
Real estate	64,597	(2,659)	8,690	9,317	(32,392)	47,553
Total	<u>\$ 277,638</u>	<u>\$ 19,399</u>	<u>\$ (15,645)</u>	<u>\$ 5,945</u>	<u>\$ (86,935)</u>	<u>\$ 200,402</u>

(a) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

Benefit Obligations — A comparison of the actuarially computed pension benefit obligation and plan assets for Xcel Energy is presented in the following table:

(Thousands of Dollars)	2015	2014
Accumulated Benefit Obligation at Dec. 31	\$ 3,368,239	\$ 3,545,928
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	\$ 3,746,752	\$ 3,440,704
Service cost	99,311	88,342
Interest cost	148,524	156,619
Actuarial (gain) loss	(169,678)	342,826
Benefit payments	(256,982)	(281,739)
Obligation at Dec. 31	<u>\$ 3,567,927</u>	<u>\$ 3,746,752</u>

(Thousands of Dollars)	2015	2014
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	\$ 3,083,771	\$ 3,010,140
Actual (loss) return on plan assets	(33,102)	224,808
Employer contributions	90,093	130,562
Benefit payments	(256,982)	(281,739)
Fair value of plan assets at Dec. 31	<u>\$ 2,883,780</u>	<u>\$ 3,083,771</u>

(Thousands of Dollars)	2015	2014
Funded Status of Plans at Dec. 31:		
Funded status ^(a)	\$ (684,147)	\$ (662,981)

(a) Amounts are recognized in noncurrent liabilities on Xcel Energy's consolidated balance sheets.

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	\$ 1,710,097	\$ 1,757,935
Prior service credit	(9,073)	(10,878)
Total	<u>\$ 1,701,024</u>	<u>\$ 1,747,057</u>

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Current regulatory assets	\$ 105,426	\$ 113,432
Noncurrent regulatory assets	1,520,975	1,558,649
Deferred income taxes	29,002	29,143
Net-of-tax accumulated OCI	45,621	45,833
Total	<u>\$ 1,701,024</u>	<u>\$ 1,747,057</u>

Measurement date	Dec. 31, 2015	Dec. 31, 2014

	2015	2014
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.66%	4.11%
Expected average long-term increase in compensation level	4.00	3.75
Mortality table	RP 2014	RP 2014

Mortality — In 2014, the Society of Actuaries published a new mortality table and projection scale that increased the overall life expectancy of males and females. Xcel Energy has reviewed its own population through a credibility analysis and adopted the RP 2014 table, with modifications, based on its population and specific experience. During 2015, a new projection table was released (MP 2015). Xcel Energy evaluated the updated projection table and concluded that the methodology, adopted at Dec. 31, 2014, is consistent with the recently updated table and continues to be representative of its population.

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2013 through 2016 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- \$125.0 million in January 2016;
- \$90.1 million in 2015;
- \$130.6 million in 2014; and
- \$192.4 million in 2013.

For future years, Xcel Energy anticipates contributions will be made as necessary.

Plan Amendments — In 2015 and 2014 there were no plan amendments made which affected the projected benefit obligation. The 2013 decrease of the projected benefit obligation for plan amendments is due to fully insuring the long-term disability benefit for NSP bargaining participants. This decrease was partially offset by an increase to the projected benefit obligation resulting from a change in the discount rate basis for lump sum conversion of annuities for participants in the Xcel Energy Pension Plan.

Benefit Costs — The components of Xcel Energy's net periodic pension cost were:

(Thousands of Dollars)	2015	2014	2013
Service cost	\$ 99,311	\$ 88,342	\$ 96,282
Interest cost	148,524	156,619	140,690
Expected return on plan assets	(213,890)	(207,205)	(198,452)
Amortization of prior service (credit) cost	(1,805)	(1,746)	5,871
Amortization of net loss	125,152	116,762	144,151
Net periodic pension cost	157,292	152,772	188,542
Costs not recognized due to effects of regulation	(29,633)	(26,315)	(36,724)
Net benefit cost recognized for financial reporting	<u>\$ 127,659</u>	<u>\$ 126,457</u>	<u>\$ 151,818</u>
	2015	2014	2013

Significant Assumptions Used to Measure Costs:

Discount rate	4.11%	4.75%	4.00%
Expected average long-term increase in compensation level	3.75	3.75	3.75
Expected average long-term rate of return on assets	7.09	7.05	6.88

Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2016 pension cost calculations is 6.87 percent.

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover substantially all employees. Total expense to these plans was approximately \$34.1 million in 2015, \$32.4 million in 2014 and \$30.3 million in 2013.

Postretirement Health Care Benefits

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees.

- NSP-Minnesota and NSP-Wisconsin discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees who retired after 1999.
- Xcel Energy discontinued contributing toward health care benefits for PSCo and SPS, nonbargaining employees retiring after June 30, 2003.
- Employees of NCE who retired in 2002 continue to receive employer-subsidized health care benefits.
- Nonbargaining employees of the former NCE who retired after 1998, bargaining employees of the former NCE who retired after 1999 and nonbargaining employees of NCE who retired after June 30, 2003, are eligible to participate in the Xcel Energy health care program with no employer subsidy.

Plan Assets — Certain state agencies that regulate Xcel Energy Inc.'s utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico jurisdictional amounts collected in rates. PSCo is required to fund postretirement benefit costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. These assets are invested in a manner consistent with the investment strategy for the pension plan.

The following table presents the target postretirement asset allocations for Xcel Energy at Dec. 31 for the upcoming year:

	2015	2014
Domestic and international equity securities	25%	25%
Short-to-intermediate fixed income securities	57	57
Alternative investments	13	13
Cash	5	5
Total	100%	100%

Xcel Energy bases its investment-return assumption for the postretirement health care fund assets on expected long-term performance for each of the investment types included in its asset portfolio. The assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected allocation of assets to selected asset classes, given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by postretirement health care assets in any year.

The following tables present, for each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2015 and 2014:

(Thousands of Dollars)	Dec. 31, 2015			
	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ 19,638	\$ —	\$ —	\$ 19,638
Government securities	—	39,241	—	39,241
Insurance contracts	—	47,205	—	47,205
Corporate bonds	—	72,876	—	72,876
Asset-backed securities	—	28,691	—	28,691
Mortgage-backed securities	—	35,612	—	35,612
Commingled funds	—	204,782	—	204,782
Other	—	(412)	—	(412)
Total	\$ 19,638	\$ 427,995	\$ —	\$ 447,633

(Thousands of Dollars)	Dec. 31, 2014			
	Level 1	Level 2	Level 3	Total
Cash equivalents ^(a)	\$ 26,324	\$ —	\$ —	\$ 26,324
Derivatives	—	186	—	186
Government securities	—	48,584	—	48,584
Insurance contracts	—	50,351	—	50,351
Corporate bonds	—	54,207	—	54,207
Asset-backed securities	—	3,619	—	3,619
Mortgage-backed securities	—	11,250	—	11,250
Commingled funds	—	282,378	—	282,378
Other	—	(1,841)	—	(1,841)
Total	<u>\$ 26,324</u>	<u>\$ 448,734</u>	<u>\$ —</u>	<u>\$ 475,058</u>

(a) Includes restricted cash of \$1.0 million at Dec. 31, 2014.

For the years ended Dec. 31, 2015 and 2014 there were no assets transferred in or out of Level 3. The following table presents the changes in Xcel Energy's Level 3 postretirement benefit plan assets for the year ended Dec. 31, 2013:

(Thousands of Dollars)	Jan. 1, 2013	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers Out of Level 3 ^(a)	Dec. 31, 2013
Private equity investments	\$ 757	\$ —	\$ —	\$ —	\$ (757)	\$ —
Real estate	39,958	—	—	—	(39,958)	—
Total	<u>\$ 40,715</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ (40,715)</u>	<u>\$ —</u>

(a) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

Benefit Obligations — A comparison of the actuarially computed benefit obligation and plan assets for Xcel Energy is presented in the following table:

(Thousands of Dollars)	2015	2014
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	\$ 642,869	\$ 731,428
Service cost	2,116	3,457
Interest cost	25,297	34,028
Medicare subsidy reimbursements	1,958	1,861
Plan participants' contributions	6,718	7,148
Actuarial gain	(45,793)	(81,699)
Benefit payments	(48,898)	(53,354)
Obligation at Dec. 31	<u>\$ 584,267</u>	<u>\$ 642,869</u>

(Thousands of Dollars)	2015	2014
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	\$ 475,058	\$ 492,036
Actual (loss) return on plan assets	(3,570)	12,083
Plan participants' contributions	6,718	7,148
Employer contributions	18,325	17,145
Benefit payments	(48,898)	(53,354)
Fair value of plan assets at Dec. 31	<u>\$ 447,633</u>	<u>\$ 475,058</u>

(Thousands of Dollars)	2015	2014
Funded Status of Plans at Dec. 31:		
Funded status	<u>\$ (136,634)</u>	<u>\$ (167,811)</u>
Noncurrent assets	1,820	1,014
Current liabilities	(7,495)	(9,110)
Noncurrent liabilities	(130,959)	(159,715)
Net postretirement amounts recognized on consolidated balance sheets	<u>\$ (136,634)</u>	<u>\$ (167,811)</u>

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	\$ 103,039	\$ 124,064
Prior service credit	(64,925)	(75,610)
Total	<u>\$ 38,114</u>	<u>\$ 48,454</u>

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Current regulatory assets	\$ 352	\$ 285
Noncurrent regulatory assets	50,135	59,697
Current regulatory liabilities	(895)	(892)
Noncurrent regulatory liabilities	(16,916)	(17,216)
Deferred income taxes	2,148	2,559
Net-of-tax accumulated OCI	3,380	4,021
Total	<u>\$ 38,114</u>	<u>\$ 48,454</u>

Measurement date Dec. 31, 2015 Dec. 31, 2014

	2015	2014
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.65%	4.08%
Mortality table	RP 2014	RP 2014
Health care costs trend rate — initial	6.00%	6.50%

Effective Jan. 1, 2016, the initial medical trend rate was decreased from 6.5 percent to 6.0 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is three years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy's retiree medical plan.

A one-percent change in the assumed health care cost trend rate would have the following effects on Xcel Energy:

(Thousands of Dollars)	One-Percentage Point	
	Increase	Decrease
APBO	\$ 56,383	\$ (47,972)
Service and interest components	3,113	(2,594)

Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy contributed \$18.3 million during 2015, \$17.1 million during 2014, \$17.6 million during 2013 and expects to contribute approximately \$12.3 million during 2016.

Plan Amendments — In 2015 and 2014, there were no plan amendments made which affected the benefit obligation.

Benefit Costs — The components of Xcel Energy's net periodic postretirement benefit costs were:

(Thousands of Dollars)	2015	2014	2013
Service cost	\$ 2,116	\$ 3,457	\$ 4,079
Interest cost	25,297	34,028	32,141
Expected return on plan assets	(26,600)	(33,954)	(33,011)
Amortization of transition obligation	—	—	825
Amortization of prior service credit	(10,686)	(10,688)	(12,501)
Amortization of net loss	5,404	11,740	22,325
Net periodic postretirement benefit cost	<u>\$ (4,469)</u>	<u>\$ 4,583</u>	<u>\$ 13,858</u>

	2015	2014	2013
Significant Assumptions Used to Measure Costs:			
Discount rate	4.08%	4.82%	4.10%
Expected average long-term rate of return on assets	5.80	7.17	7.11

Projected Benefit Payments

The following table lists Xcel Energy's projected benefit payments for the pension and postretirement benefit plans:

(Thousands of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2016	\$ 260,240	\$ 48,047	\$ 2,355	\$ 45,692
2017	255,206	47,460	2,493	44,967
2018	263,689	47,039	2,637	44,402
2019	268,975	46,522	2,761	43,761
2020	271,853	46,819	2,869	43,950
2021-2025	1,353,351	220,122	16,053	204,069

Multiemployer Plans

NSP-Minnesota and NSP-Wisconsin each contribute to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees, including electrical workers, boilermakers, and other construction and facilities workers who may perform services for more than one employer during a given period and do not participate in the NSP-Minnesota and NSP-Wisconsin sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota and NSP-Wisconsin sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

Contributions to multiemployer plans were as follows for the years ended Dec. 31, 2015, 2014 and 2013. The average number of NSP-Minnesota union employees covered by the multiemployer pension plans decreased to approximately 900 in 2015 from approximately 1,000 in 2014. There were no other significant changes to the nature or magnitude of the participation of NSP-Minnesota and NSP-Wisconsin in multiemployer plans for the years presented:

(Thousands of Dollars)	2015	2014	2013
Multiemployer pension contributions:			
NSP-Minnesota	\$ 17,223	\$ 20,254	\$ 23,515
NSP-Wisconsin	944	156	130
Total	<u>\$ 18,167</u>	<u>\$ 20,410</u>	<u>\$ 23,645</u>
Multiemployer other postretirement benefit contributions:			
NSP-Minnesota	\$ 135	\$ 273	\$ 390
Total	<u>\$ 135</u>	<u>\$ 273</u>	<u>\$ 390</u>

10. Other Income, Net

Other income, net for the years ended Dec. 31 consisted of the following:

(Thousands of Dollars)	2015	2014	2013
Interest income	\$ 5,737	\$ 7,353	\$ 8,343
Other nonoperating income	3,514	4,866	3,025
Insurance policy expense	(3,851)	(6,923)	(8,292)
Other nonoperating expense	—	—	(104)
Other income, net	<u>\$ 5,400</u>	<u>\$ 5,296</u>	<u>\$ 2,972</u>

11. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, international equity funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds and international equity funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on Xcel Energy's evaluation of its redemption rights, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2. When contractual settlements extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota include transmission congestion instruments, generally referred to as FTRs, purchased from MISO, PJM, ERCOT, SPP and NYISO. Electric commodity derivatives held by SPS include FTRs purchased from SPP. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of energy congestion, which is caused by overall transmission load and other transmission constraints. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR. The valuation process for FTRs utilizes complex iterative modeling to predict the impacts of forecasted changes in these drivers of transmission system congestion on the historical pricing of FTR purchases.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of management's forecasts for several of the inputs to this complex valuation model – including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms as applicable in each jurisdiction, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of NSP-Minnesota and SPS, the numerous unobservable quantitative inputs to the complex model used for valuation of FTRs are insignificant to the consolidated financial statements of Xcel Energy.

Non-Derivative Instruments Fair Value Measurements

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and PI nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins. NSP-Minnesota uses the MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the nuclear decommissioning fund were \$328.8 million and \$312.1 million at Dec. 31, 2015 and 2014, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were \$100.2 million and \$74.1 million at Dec. 31, 2015 and 2014, respectively.

The following tables present the cost and fair value of Xcel Energy's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund at Dec. 31, 2015 and 2014:

(Thousands of Dollars)	Dec. 31, 2015				
	Cost	Fair Value			Total
		Level 1	Level 2	Level 3	
Nuclear decommissioning fund ^(a)					
Cash equivalents	\$ 27,484	\$ 27,484	\$ —	\$ —	\$ 27,484
Commingled funds	392,838	—	410,634	—	410,634
International equity funds	259,114	—	231,122	—	231,122
Private equity investments	105,965	—	—	157,528	157,528
Real estate	61,816	—	—	84,750	84,750
Debt securities:					
Government securities	24,444	—	21,356	—	21,356
U.S. corporate bonds	73,061	—	65,276	—	65,276
International corporate bonds	13,726	—	12,801	—	12,801
Municipal bonds	49,255	—	51,589	—	51,589
Asset-backed securities	2,837	—	2,830	—	2,830
Mortgage-backed securities	11,444	—	11,621	—	11,621
Equity securities:					
Common stock	473,615	647,159	—	—	647,159
Total	\$ 1,495,599	\$ 674,643	\$ 807,229	\$ 242,278	\$ 1,724,150

^(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes \$130.0 million of equity investments in unconsolidated subsidiaries and \$48.9 million of miscellaneous investments.

Dec. 31, 2014

(Thousands of Dollars)	Cost	Fair Value			
		Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund ^(a)					
Cash equivalents	\$ 24,184	\$ 24,184	\$ —	\$ —	\$ 24,184
Commingled funds	470,013	—	465,615	—	465,615
International equity funds	80,454	—	78,721	—	78,721
Private equity investments	73,936	—	—	101,237	101,237
Real estate	43,859	—	—	64,249	64,249
Debt securities:					
Government securities	30,674	—	28,808	—	28,808
U.S. corporate bonds	81,463	—	77,562	—	77,562
International corporate bonds	16,950	—	16,341	—	16,341
Municipal bonds	242,282	—	249,201	—	249,201
Asset-backed securities	9,131	—	9,250	—	9,250
Mortgage-backed securities	23,225	—	23,895	—	23,895
Equity securities:					
Common stock	369,751	564,858	—	—	564,858
Total	<u>\$ 1,465,922</u>	<u>\$ 589,042</u>	<u>\$ 949,393</u>	<u>\$ 165,486</u>	<u>\$ 1,703,921</u>

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes \$83.1 million of equity investments in unconsolidated subsidiaries and \$45.6 million of miscellaneous investments.

The following tables present the changes in Level 3 nuclear decommissioning fund investments:

(Thousands of Dollars)	Jan. 1, 2015	Purchases	Settlements	Gains Recognized as Regulatory Assets ^(a)	Transfers Out of Level 3	Dec. 31, 2015
Private equity investments	\$ 101,237	\$ 32,029	\$ —	\$ 24,262	\$ —	\$ 157,528
Real estate	64,249	27,568	(9,611)	2,544	—	84,750
Total	<u>\$ 165,486</u>	<u>\$ 59,597</u>	<u>\$ (9,611)</u>	<u>\$ 26,806</u>	<u>\$ —</u>	<u>\$ 242,278</u>

(Thousands of Dollars)	Jan. 1, 2014	Purchases	Settlements	Gains Recognized as Regulatory Assets ^(a)	Transfers Out of Level 3	Dec. 31, 2014
Private equity investments	\$ 62,696	\$ 22,078	\$ (286)	\$ 16,749	\$ —	\$ 101,237
Real estate	57,368	8,088	(9,794)	8,587	—	64,249
Total	<u>\$ 120,064</u>	<u>\$ 30,166</u>	<u>\$ (10,080)</u>	<u>\$ 25,336</u>	<u>\$ —</u>	<u>\$ 165,486</u>

(Thousands of Dollars)	Jan. 1, 2013	Purchases	Settlements	Gains Recognized as Regulatory Assets ^(a)	Transfers Out of Level 3 ^(b)	Dec. 31, 2013
Private equity investments	\$ 33,250	\$ 24,201	\$ —	\$ 5,245	\$ —	\$ 62,696
Real estate	39,074	31,626	(18,622)	5,290	—	57,368
Asset-backed securities	2,067	—	—	—	(2,067)	—
Mortgage-backed securities	30,209	—	—	—	(30,209)	—
Total	<u>\$ 104,600</u>	<u>\$ 55,827</u>	<u>\$ (18,622)</u>	<u>\$ 10,535</u>	<u>\$ (32,276)</u>	<u>\$ 120,064</u>

(a) Gains and losses are deferred as a component of the regulatory asset for nuclear decommissioning.

(b) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements and were subsequently sold during 2013.

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at Dec. 31, 2015:

(Thousands of Dollars)	Final Contractual Maturity				Total
	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	
Government securities	\$ —	\$ —	\$ —	\$ 21,356	\$ 21,356
U.S. corporate bonds	—	16,005	51,384	(2,113)	65,276
International corporate bonds	—	2,787	9,382	632	12,801
Municipal bonds	153	264	17,814	33,358	51,589
Asset-backed securities	—	—	2,830	—	2,830
Mortgage-backed securities	—	—	—	11,621	11,621
Debt securities	<u>\$ 153</u>	<u>\$ 19,056</u>	<u>\$ 81,410</u>	<u>\$ 64,854</u>	<u>\$ 165,473</u>

Derivative Instruments Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — Xcel Energy enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

At Dec. 31, 2015, accumulated other comprehensive losses related to interest rate derivatives included \$3.6 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for unsettled hedges, as applicable.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments. Xcel Energy's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel and weather derivatives.

At Dec. 31, 2015, Xcel Energy had various vehicle fuel contracts designated as cash flow hedges extending through December 2016. Xcel Energy also enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in OCI or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the years ended Dec. 31, 2015 and 2014.

At Dec. 31, 2015, net losses related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included \$0.2 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

The following table details the gross notional amounts of commodity forwards, options and FTRs at Dec. 31:

(Amounts in Thousands) ^{(a)(b)}	2015	2014
MWh of electricity	50,487	56,361
MMBtu of natural gas	20,874	927
Gallons of vehicle fuel	141	282

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Xcel Energy's own credit risk when determining the fair value of derivative liabilities, the impact of considering credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

Xcel Energy Inc. and its subsidiaries employ additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

Xcel Energy's utility subsidiaries' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities. At Dec. 31, 2015, two of Xcel Energy's 10 most significant counterparties for these activities, comprising \$18.8 million or 9 percent of this credit exposure, had investment grade credit ratings from S&P's, Moody's or Fitch Ratings. Six of the 10 most significant counterparties, comprising \$66.3 million or 30 percent of this credit exposure, were not rated by these external agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. The remaining two most significant counterparties, comprising \$11.3 million or 5 percent of this credit exposure, had credit quality less than investment grade, based on ratings from external and internal analysis. Nine of these significant counterparties are municipal or cooperative electric entities or other utilities.

Financial Impact of Qualifying Cash Flow Hedges — The impact of qualifying interest rate and vehicle fuel cash flow hedges on Xcel Energy's accumulated other comprehensive loss, included in the consolidated statements of common stockholders' equity and in the consolidated statements of comprehensive income, is detailed in the following table:

(Thousands of Dollars)	2015	2014	2013
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	\$ (57,628)	\$ (59,753)	\$ (61,241)
After-tax net unrealized (losses) gains related to derivatives accounted for as hedges	(70)	(163)	12
After-tax net realized losses on derivative transactions reclassified into earnings	2,836	2,288	1,476
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	<u>\$ (54,862)</u>	<u>\$ (57,628)</u>	<u>\$ (59,753)</u>

The following tables detail the impact of derivative activity during the years ended Dec. 31, 2015, 2014 and 2013, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Year Ended Dec. 31, 2015				
	Pre-Tax Fair Value Losses Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		Pre-Tax Losses Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	\$ —	\$ —	\$ 4,515 ^(a)	\$ —	\$ —
Vehicle fuel and other commodity	(116)	—	131 ^(b)	—	—
Total	<u>\$ (116)</u>	<u>\$ —</u>	<u>\$ 4,646</u>	<u>\$ —</u>	<u>\$ —</u>
Other derivative instruments					
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ (7,286) ^(c)
Electric commodity	—	(18,543)	—	16,338 ^(d)	—
Natural gas commodity	—	(16,163)	—	15,694 ^(e)	(11,840) ^(e)
Total	<u>\$ —</u>	<u>\$ (34,706)</u>	<u>\$ —</u>	<u>\$ 32,032</u>	<u>\$ (19,126)</u>

Year Ended Dec. 31, 2014

(Thousands of Dollars)	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	\$ —	\$ —	\$ 3,836 ^(a)	\$ —	\$ —
Vehicle fuel and other commodity	(266)	—	(55) ^(b)	—	—
Total	<u>\$ (266)</u>	<u>\$ —</u>	<u>\$ 3,781</u>	<u>\$ —</u>	<u>\$ —</u>
Other derivative instruments					
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ 881 ^(c)
Electric commodity	—	(8,306)	—	(9,036) ^(d)	—
Natural gas commodity	—	5,166	—	(13,997) ^(e)	(13,220) ^(e)
Other commodity	—	—	—	—	643 ^(c)
Total	<u>\$ —</u>	<u>\$ (3,140)</u>	<u>\$ —</u>	<u>\$ (23,033)</u>	<u>\$ (11,696)</u>

Year Ended Dec. 31, 2013

(Thousands of Dollars)	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	\$ —	\$ —	\$ 4,107 ^(a)	\$ —	\$ —
Vehicle fuel and other commodity	29	—	(90) ^(b)	—	—
Total	<u>\$ 29</u>	<u>\$ —</u>	<u>\$ 4,017</u>	<u>\$ —</u>	<u>\$ —</u>
Other derivative instruments					
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ 11,221 ^(c)
Electric commodity	—	75,817	—	(52,796) ^(d)	—
Natural gas commodity	—	(3,088)	—	5,019 ^(e)	(6,589) ^(d)
Total	<u>\$ —</u>	<u>\$ 72,729</u>	<u>\$ —</u>	<u>\$ (47,777)</u>	<u>\$ 4,632</u>

(a) Amounts are recorded to interest charges.

(b) Amounts are recorded to O&M expenses.

(c) Amounts are recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(d) Amounts are recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Amounts for the year ended Dec. 31, 2015 included \$1.1 million of settlement losses on derivatives entered to mitigate natural gas price risk for electric generation, recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Such losses for the years ended Dec. 31, 2014 and 2013 were immaterial. The remaining settlement losses for the years ended Dec. 31, 2015, 2014 and 2013 relate to natural gas operations and are recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2015, 2014 and 2013. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those recorded to the consolidated balance sheet at fair value, as well as those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheet, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary is unable to maintain its credit ratings. At Dec. 31, 2015 and 2014, there were no derivative instruments with contract provisions that required the posting of collateral or settlement of applicable outstanding contracts if the credit ratings of Xcel Energy Inc.'s utility subsidiaries were downgraded below investment grade.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2015 and 2014.

Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2015:

	Dec. 31, 2015						
	Fair Value			Fair Value Total	Counterparty Netting ^(b)	Total	
(Thousands of Dollars)	Level 1	Level 2	Level 3				
Current derivative assets							
Other derivative instruments:							
Commodity trading	\$ 225	\$ 10,620	\$ 1,250	\$ 12,095	\$ (5,865)	\$ 6,230	
Electric commodity	—	—	21,421	21,421	(4,088)	17,333	
Natural gas commodity	—	496	—	496	(303)	193	
Total current derivative assets	<u>\$ 225</u>	<u>\$ 11,116</u>	<u>\$ 22,671</u>	<u>\$ 34,012</u>	<u>\$ (10,256)</u>	<u>23,756</u>	
PPAs ^(a)						10,086	
Current derivative instruments						<u>\$ 33,842</u>	
Noncurrent derivative assets							
Other derivative instruments:							
Commodity trading	\$ —	\$ 27,416	\$ —	\$ 27,416	\$ (6,555)	\$ 20,861	
Total noncurrent derivative assets	<u>\$ —</u>	<u>\$ 27,416</u>	<u>\$ —</u>	<u>\$ 27,416</u>	<u>\$ (6,555)</u>	<u>20,861</u>	
PPAs ^(a)						30,222	
Noncurrent derivative instruments						<u>\$ 51,083</u>	
Dec. 31, 2015							
	Fair Value			Fair Value Total	Counterparty Netting ^(b)	Total	
(Thousands of Dollars)	Level 1	Level 2	Level 3				
Current derivative liabilities							
Derivatives designated as cash flow hedges:							
Vehicle fuel and other commodity	\$ —	\$ 205	\$ —	\$ 205	\$ —	\$ 205	
Other derivative instruments:							
Commodity trading	152	7,866	555	8,573	(6,904)	1,669	
Electric commodity	—	—	4,088	4,088	(4,088)	—	
Natural gas commodity	—	5,407	—	5,407	(303)	5,104	
Total current derivative liabilities	<u>\$ 152</u>	<u>\$ 13,478</u>	<u>\$ 4,643</u>	<u>\$ 18,273</u>	<u>\$ (11,295)</u>	<u>6,978</u>	
PPAs ^(a)						22,861	
Current derivative instruments						<u>\$ 29,839</u>	
Noncurrent derivative liabilities							
Derivatives designated as cash flow hedges:							
Commodity trading	\$ —	\$ 19,898	\$ —	\$ 19,898	\$ (9,780)	\$ 10,118	
Total noncurrent derivative liabilities	<u>\$ —</u>	<u>\$ 19,898</u>	<u>\$ —</u>	<u>\$ 19,898</u>	<u>\$ (9,780)</u>	<u>10,118</u>	
PPAs ^(a)						158,193	
Noncurrent derivative instruments						<u>\$ 168,311</u>	

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2015. At Dec. 31, 2015, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of \$4.3 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2014:

	Dec. 31, 2014					
	Fair Value			Fair Value Total	Counterparty Netting ^(b)	Total
(Thousands of Dollars)	Level 1	Level 2	Level 3			
Current derivative assets						
Other derivative instruments:						
Commodity trading	\$ —	\$ 14,326	\$ 4,732	\$ 19,058	\$ (3,240)	\$ 15,818
Electric commodity	—	—	62,825	62,825	(11,402)	51,423
Natural gas commodity	—	381	—	381	(22)	359
Total current derivative assets	<u>\$ —</u>	<u>\$ 14,707</u>	<u>\$ 67,557</u>	<u>\$ 82,264</u>	<u>\$ (14,664)</u>	<u>67,600</u>
PPAs ^(a)						18,123
Current derivative instruments						<u>\$ 85,723</u>
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	\$ —	\$ 17,617	\$ —	\$ 17,617	\$ (4,151)	\$ 13,466
Total noncurrent derivative assets	<u>\$ —</u>	<u>\$ 17,617</u>	<u>\$ —</u>	<u>\$ 17,617</u>	<u>\$ (4,151)</u>	<u>13,466</u>
PPAs ^(a)						40,309
Noncurrent derivative instruments						<u>\$ 53,775</u>

	Dec. 31, 2014						
	Fair Value			Fair Value Total	Counterparty Netting ^(b)	Total	
(Thousands of Dollars)	Level 1	Level 2	Level 3				
Current derivative liabilities							
Derivatives designated as cash flow hedges:							
Vehicle fuel and other commodity	\$ —	\$ 118	\$ —	\$ 118	\$ —	\$ 118	
Other derivative instruments:							
Commodity trading	—	7,974	—	7,974	(7,974)	—	
Electric commodity	—	—	11,402	11,402	(11,402)	—	
Natural gas commodity	—	548	—	548	(21)	527	
Total current derivative liabilities	<u>\$ —</u>	<u>\$ 8,640</u>	<u>\$ 11,402</u>	<u>\$ 20,042</u>	<u>\$ (19,397)</u>	645	
PPAs ^(a)						20,987	
Current derivative instruments						<u>\$ 21,632</u>	
Noncurrent derivative liabilities							
Derivatives designated as cash flow hedges:							
Vehicle fuel and other commodity	\$ —	\$ 102	\$ —	\$ 102	\$ —	\$ 102	
Other derivative instruments:							
Commodity trading	—	6,890	—	6,890	(6,033)	857	
Natural gas commodity	—	35	—	35	—	35	
Total noncurrent derivative liabilities	<u>\$ —</u>	<u>\$ 7,027</u>	<u>\$ —</u>	<u>\$ 7,027</u>	<u>\$ (6,033)</u>	994	
PPAs ^(a)						182,942	
Noncurrent derivative instruments						<u>\$ 183,936</u>	

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2014. At Dec. 31, 2014, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of \$6.6 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents the changes in Level 3 commodity derivatives for the years ended Dec. 31, 2015, 2014 and 2013:

(Thousands of Dollars)	Year Ended Dec. 31		
	2015	2014	2013
Balance at Jan. 1	\$ 56,155	\$ 41,660	\$ 16,649
Purchases	63,712	135,008	61,474
Settlements	(69,754)	(145,974)	(45,199)
Transfers out of Level 3	—	(1,093)	—
Net transactions recorded during the period:			
Gains recognized in earnings ^(a)	1,533	10,692	3,947
(Losses) gains recognized as regulatory assets and liabilities	(33,618)	15,862	4,789
Balance at Dec. 31	<u>\$ 18,028</u>	<u>\$ 56,155</u>	<u>\$ 41,660</u>

(a) These amounts relate to commodity derivatives held at the end of the period.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the years ended Dec. 31, 2015 and 2013. The transfer of amounts from Level 3 to Level 2 in the year ended Dec. 31, 2014 was due to the valuation of certain long-term derivative contracts for which observable commodity pricing forecasts became a more significant input during the period.

Fair Value of Long-Term Debt

As of Dec. 31, 2015 and 2014, other financial instruments for which the carrying amount did not equal fair value were as follows:

(Thousands of Dollars)	2015		2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	\$ 13,147,740	\$ 14,094,744	\$ 11,757,360	\$ 13,360,236

The fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of Dec. 31, 2015 and 2014, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

12. Rate Matters

NSP-Minnesota

Pending and Recently Concluded Regulatory Proceedings — MPUC

NSP-Minnesota – Minnesota 2014 Multi-Year Electric Rate Case — In November 2013, NSP-Minnesota filed a two-year electric rate case with the MPUC. The rate case was based on a ROE of 10.25 percent, a 52.5 percent equity ratio, a 2014 average electric rate base of \$6.67 billion and an additional average rate base of \$412 million in 2015. The NSP-Minnesota electric rate case initially reflected a requested increase in revenues of approximately \$193 million, or 6.9 percent, in 2014 and an additional \$98 million, or 3.5 percent, in 2015. The request included a proposed rate moderation plan. In December 2013, the MPUC approved interim rates of \$127 million, effective Jan. 3, 2014, subject to refund. In 2014, NSP-Minnesota revised its requested rate increase to \$115.3 million for 2014 and to \$106.0 million for 2015, for a total combined unadjusted increase of \$221.3 million.

In May 2015, the MPUC ordered a total increase of \$166.1 million, or 5.9 percent, consisting of \$58.9 million and \$125.2 million in 2014 and 2015, respectively, and an \$18.0 million adjustment related to disallowance of certain Monticello LCM/EPU costs. The MPUC also approved a three-year, decoupling pilot with a 3 percent cap on base revenue for the residential and small commercial and industrial classes, based on actual sales, effective Jan. 1, 2016. The decoupling mechanism would eliminate the impact of changes in electric sales due to conservation and weather variability for these classes.

In July 2015, the MPUC deliberated on requests for reconsideration and determined the Monticello EPU project was not yet used-and-useful, as final approval related to the full EPU uprate condition had not been received from the NRC as of June 30, 2015. As a result, \$13.8 million was excluded from final rates. Monticello subsequently received final NRC compliance approval in July 2015. The MPUC also approved 2015 interim rates effective March 3, 2015 and stated that the 2014 interim rate refund obligation be netted against the 2015 interim rate revenue under-collections.

The MPUC's decisions resulted in a total estimated 2014 and 2015 annual rate increase of \$149.4 million, or 5.3 percent.

The following table outlines the impact of the MPUC's July decision:

(Millions of Dollars)	MPUC July Decision
2014 and 2015 step increase - based on MPUC May order	\$ 166.1
Reconsideration/clarification adjustments:	
2015 Monticello EPU used-and-useful adjustment	(13.8)
2014 property tax final true-up	(3.1)
Other, net.	0.2
Total 2014 and 2015 step increase	\$ 149.4
Impact of interim rate effective March 3, 2015.	(3.6)
Estimated revenue impact.	<u>\$ 145.8</u>

NSP-Minnesota – Minnesota 2016 Multi-Year Electric Rate Case — In November 2015, NSP-Minnesota filed a three-year electric rate case with the MPUC. The rate case is based on a requested ROE of 10.0 percent and a 52.50 percent equity ratio. The request is detailed in the table below.

Request (Millions of Dollars)	2016	2017	2018
Rate request	\$ 194.6	\$ 52.1	\$ 50.4
Increase percentage	6.4%	1.7%	1.7%
Interim request	\$ 163.7	\$ 44.9	N/A
Rate base	\$ 7,800	\$ 7,700	\$ 7,700

NSP-Minnesota also proposed a five-year alternative plan that would extend the rate plan two additional years.

In addition, NSP-Minnesota has requested the MPUC encourage parties to engage in a formal mediation type procedure as outlined by Minnesota's rate case statute which may streamline the settlement process.

In December 2015, the MPUC approved interim rates for 2016. The MPUC deferred making a decision on incremental interim rates for 2017 and indicated that NSP-Minnesota could bring back its request in the fourth quarter of 2016. The MPUC also required NSP-Minnesota to file supplemental direct testimony addressing costs associated with the LCM at the PI nuclear plant. NSP-Minnesota filed supplemental testimony in January 2016 demonstrating that the capital work at PI, including the LCM, is required during the rate case period, higher costs associated with the LCM are necessary to operate the plant through the end of its licensed life and recovery of these costs will result in reasonably priced energy for customers.

The major components of the requested rate increase are summarized below:

(Millions of Dollars)	2016	2017	2018	Total
2014 multi-year rate case items:				
Excess depreciation reserve	\$ 26.0	\$ 51.0	\$ —	\$ 77.0
DOE settlement	25.7	—	—	25.7
Monticello LCM/EPU	11.2	(1.6)	(1.5)	8.1
	<u>62.9</u>	<u>49.4</u>	<u>(1.5)</u>	<u>110.8</u>
Additional items:				
Capital investments	128.7	12.8	44.6	186.1
Property taxes	30.2	7.6	5.2	43.0
NOL carryforwards	(6.3)	(24.5)	(6.5)	(37.3)
Other costs	(20.9)	6.8	8.6	(5.5)
	<u>131.7</u>	<u>2.7</u>	<u>51.9</u>	<u>186.3</u>
Total rate request.	<u>\$ 194.6</u>	<u>\$ 52.1</u>	<u>\$ 50.4</u>	<u>\$ 297.1</u>

The next steps in the procedural schedule are expected to be as follows:

- Intervenors' direct testimony — June 14, 2016;
- Rebuttal testimony — Aug. 9, 2016;
- Surrebuttal testimony — Sept. 16, 2016;
- Settlement conference — Sept. 26, 2016;

- Evidentiary hearing — Oct. 4-7, 2016;
- ALJ report — Feb. 21, 2017; and
- MPUC order — June 1, 2017.

NSP-Minnesota – Nuclear Project Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello LCM/EPU project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 MW. The Monticello LCM/EPU project expenditures were approximately \$665 million. Total capitalized costs were approximately \$748 million, which includes AFUDC. In 2008, project expenditures were initially estimated at approximately \$320 million, excluding AFUDC.

In 2013, the MPUC initiated an investigation to determine whether the final costs for the Monticello LCM/EPU project were prudent.

In March 2015, the MPUC voted to allow for full recovery, including a return, on approximately \$415 million of the total plant costs (inclusive of AFUDC), but only allow recovery of the remaining \$333 million of costs with no return on this portion of the investment over the remaining life of the plant. Further, the MPUC determined that only 50 percent of the investment was considered used-and-useful for 2014. As a result of these determinations, Xcel Energy recorded an estimated pre-tax loss of \$129 million in the first quarter of 2015, after which the remaining book value of the Monticello project represented the present value of the estimated future cash flows.

NSP-Minnesota – 2016 TCR Filing — In October 2015, NSP-Minnesota submitted its 2016 TCR filing with the MPUC, requesting recovery of \$19.2 million of 2016 transmission investment costs not included in electric base rates. This filing included an option to keep approximately \$59.1 million of revenue requirements associated with two CapX2020 projects completed in 2015 within the TCR rider or to include these revenue requirements in electric base rates during the interim rate implementation of the next electric rate case. In November 2015, NSP-Minnesota submitted an update to its TCR filing in which it confirmed that it was requesting the MPUC approve keeping the two CapX2020 projects in the TCR rider, increasing the revenue requirements to \$78.3 million, until the conclusion of the 2016 Minnesota electric rate case.

Recently Concluded Regulatory Proceedings — SDPUC

NSP-Minnesota – South Dakota Infrastructure Rider — In December 2015, the SDPUC approved recovery of \$10.2 million through the infrastructure rider effective beginning Jan. 1, 2016. As part of the South Dakota 2015 electric rate case, the infrastructure rider was refreshed with new projects and was also expanded as a mechanism to allow for possible recovery of other investments related to generation, transmission, and distribution.

Electric, Purchased Gas and Resource Adjustment Clauses

CIP and CIP Rider — In December 2012, the MPUC approved reductions to the CIP financial incentive mechanisms effective for the 2013 through 2015 program years and in 2015 extended the mechanisms to the 2016 program year. The estimated average annual electric and natural gas incentives are \$30.6 million and \$3.6 million, respectively, based on the approved savings goals.

CIP expenses are recovered through base rates and a rider that is adjusted annually.

- In July 2015, the MPUC approved NSP-Minnesota's 2014 CIP electric and natural gas financial incentives totaling \$40.1 million and \$5.8 million, respectively.
- In addition, the MPUC approved NSP-Minnesota's proposed 2015 to 2016 electric and natural gas CIP riders. NSP-Minnesota estimates 2016 recovery of \$21.5 million of electric CIP expenses and \$9.2 million of natural gas CIP expenses.
- This proposed recovery through the riders is in addition to an estimated \$86.9 million and \$3.7 million through electric and gas base rates, respectively.

NSP-Minnesota – Gas Utility Infrastructure Cost (GUIC) Rider — In October 2015, NSP-Minnesota filed the GUIC rider with the MPUC for approval to recover the cost of natural gas infrastructure investments in Minnesota to improve safety and reliability. Costs include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs. Sewer separation costs stem from the inspection of sewer lines and the redirection of gas pipes in the event their paths are in conflict. NSP-Minnesota requested recovery of approximately \$15.5 million from Minnesota gas utility customers beginning April 1, 2016. This request includes \$1.9 million in over-recovery from 2015 and \$4.5 million of deferred sewer separation and integrity management costs which is the 2016 portion of a five year amortization.

An MPUC decision is expected in the second half of 2016.

NSP-Wisconsin

Recently Concluded Regulatory Proceedings — PSCW

NSP-Wisconsin – Wisconsin 2016 Electric and Gas Rate Case — In May 2015, NSP-Wisconsin filed a request with the PSCW seeking an increase in annual electric rates of \$27.4 million, or 3.9 percent, and an increase in natural gas rates of \$5.9 million, or 5.0 percent, effective Jan. 1 2016. The rate filing was based on a 2016 forecast test year, a ROE of 10.2 percent, an equity ratio of 52.5 percent and a forecasted average rate base of approximately \$1.2 billion for the electric utility and \$111.2 million for the natural gas utility.

In December 2015, the PSCW approved an electric rate increase of approximately \$7.6 million, or 1.1 percent, and a natural gas rate increase of \$4.2 million, or 3.6 percent, based on a 10.0 percent ROE and an equity ratio of 52.5 percent. New rates went into effect in January 2016. As shown below, NSP-Wisconsin received approximately 65 percent of the non-fuel and purchased power portion of its requested electric rate increase and 71 percent of its requested natural gas rate increase.

The major components of the requested rate increases and the PSCW's approval are summarized as follows:

Electric Rate Request (Millions of Dollars)	NSP-Wisconsin Request	PSCW Approval
Capital investments	\$ 23.0	\$ 13.9
ROE & other capital structure adjustments	—	(3.8)
Generation and transmission expenses (excluding fuel and purchased power)	37.2	42.7
O&M expenses	11.1	3.2
Sales forecast	(27.0)	(27.0)
Rate increase - non-fuel and purchased power	44.3	29.0
Rate reduction - fuel and purchased power	(16.9)	(21.4)
Total electric rate increase	<u>\$ 27.4</u>	<u>\$ 7.6</u>

Natural Gas Rate Request (Millions of Dollars)	NSP-Wisconsin Request	PSCW Approval
Capital investments	\$ 3.7	\$ 3.7
ROE & other capital structure adjustments	—	(0.4)
O&M expenses	3.2	1.9
Environmental remediation expenses	2.9	2.9
Sales forecast	(3.9)	(3.9)
Total natural gas rate increase	<u>\$ 5.9</u>	<u>\$ 4.2</u>

PSCo

Pending and Recently Concluded Regulatory Proceedings — CPUC

PSCo – Colorado 2015 Multi-Year Gas Rate Case — In March 2015, PSCo filed a multi-year request with the CPUC to increase Colorado retail natural gas base rates by \$66.2 million over three years. The request was based on a HTY ended June 30, 2014 adjusted for known and measurable expenses and capital additions for each of the periods in the MYP and an equity ratio of 56 percent. In addition, PSCo requested an extension of its PSIA rider through 2020 to recover costs associated with its pipeline integrity efforts. The rider would recover incremental revenue of \$42.8 million over three years.

In July 2015, PSCo filed rebuttal testimony with adjustments and modified recovery between base rates and the PSIA rider. The revised request is summarized below:

(Millions of Dollars)	2015	2016 Step	2017 Step
PSCo's filed base rate request	\$ 40.5	\$ 7.6	\$ 18.1
Shift O&M expenses between PSIA and base rates	—	7.0	6.4
Rebuttal corrections and adjustments	—	—	(7.7)
Total base rate increase	\$ 40.5	\$ 14.6	\$ 16.8
Incremental PSIA rider revenues	(0.1)	14.7	21.7
Total revenue impact from rebuttal	\$ 40.4	\$ 29.3	\$ 38.5
Requested ROE	10.1%	10.1%	10.3%
Rate base	\$ 1,260	\$ 1,310	\$ 1,360

In November 2015, the ALJ issued his recommended decision, which reflected a 2014 HTY with a 13-month average rate base, the Cherokee pipeline investment adjusted to year-end rate base, a ROE of 9.5 percent and an equity ratio of 56.51 percent. In addition, the ALJ's recommendation included a three-year extension (2016 through 2018) of the PSIA rider with all O&M expenses transferred to base rates as well as certain other projects shifting between the PSIA rider and base rates, beginning January 2016. The ALJ also recommended that certain expenses, including property taxes and damage prevention costs that exceed the 2014 HTY level, be deferred. He further recommended a pension cost tracker and certain other deferral related items.

In February 2016, the CPUC issued their written order. Key matters are as follows:

- 2014 HTY, with a 13-month average rate base, with the exception of the Cherokee pipeline which is included at a year-end level;
- Extension of the PSIA rider through 2018 with all O&M expenses transferred to base rates;
- A ROE of 9.5 percent; and
- An equity ratio of 56.51 percent.

The following table reflects the ALJ's position and the CPUC's written order (estimated):

(Millions of Dollars)	ALJ	CPUC's Written Order
PSCo's filed 2015 base rate request ^(a)	\$ 40.5	\$ 40.5
ROE	(7.8)	(7.8)
Capital structure and cost of debt	(0.5)	(0.5)
Cherokee pipeline adjustment	4.1	4.1
Move to 2014 HTY	(14.1)	(14.1)
O&M expenses	(3.0)	(2.4)
Other, net	(1.1)	(1.1)
Overall recommended rate increase	\$ 18.1	\$ 18.7

^(a) The ALJ's recommendation and the CPUC's written order also includes approximately \$20.0 million of PSIA costs be transferred to base rates, effective Jan. 1, 2016.

The ALJ's recommendation, as well as the CPUC's written order for the PSIA rider, are as follows (estimated):

(Millions of Dollars)	ALJ		CPUC's Written Order	
	2016	2017	2016	2017
PSCo's filed incremental PSIA request	\$ 21.7	\$ 21.2	\$ 21.7	\$ 21.2
Transfer PSIA costs to base rates	(20.5)	—	(20.5)	—
PSIA cost recovery remaining in base	(4.3)	—	(4.3)	—
Projects not recovered through the PSIA	(3.6)	(2.0)	(3.3)	(0.8)
ROE and capital structure	(0.3)	(1.6)	(0.3)	(1.6)
Total	\$ (7.0)	\$ 17.6	\$ (6.7)	\$ 18.8

The following table summarizes the estimated annual pre-tax impact of the CPUC's written order:

(Millions of Dollars)	2015	2016	2017
Base rate increase	\$ 18.7	\$ 19.7	\$ —
Incremental PSIA rider revenues	(0.2)	(6.7)	18.8
Expense deferrals, net amortization ^(a)	(3.6)	1.5	5.2
Estimated pre-tax impact	<u>\$ 14.9</u>	<u>\$ 14.5</u>	<u>\$ 24.0</u>

(a) Deferral and amortization impacts relate primarily to recognition of accelerated amortization of prepaid pension assets and deferrals of pension expense in excess of the amount approved in the prior general gas rate case.

Interim rates, subject to refund, went into effect Oct. 1, 2015. PSCo has recognized management's best estimate of the potential customer refund obligation.

PSCo – Colorado 2015 Steam Rate Case — In November 2015, PSCo filed a request to increase Colorado retail steam rates by \$3.5 million in 2016. In December 2015, the CPUC approved the filed request which recovers costs related to upgrades for the state steam plant as well as the Zuni Station and permits use of the Zuni Station exclusively for steam business. Final rates are implemented in two steps with \$2.8 million, which began on Jan. 1, 2016, and the remaining \$0.7 million which will be effective Nov. 1, 2016.

PSCo – Annual Electric Earnings Test — In February 2015, in the Colorado 2014 Electric Rate Case, the CPUC approved an annual earnings test in which PSCo shares with customers earnings that exceed the authorized ROE threshold of 9.83 percent for 2015 through 2017. As of Dec. 31, 2015, PSCo has recognized management's best estimate of the expected customer refund obligation for the 2015 earnings test of \$15 million. PSCo will file its 2015 earnings test with the CPUC in April 2016. The final sharing obligation will be based on the CPUC approved tariff and could vary from the current estimate.

Electric, Purchased Gas and Resource Adjustment Clauses

DSM and the DSMCA — Energy efficiency and DSM costs are recovered through a combination of the DSMCA riders and base rates. DSMCA riders are adjusted biannually to capture program costs, performance incentives, and any over- or under-recoveries are true-up in the following year. Savings goals were 384 GWh in 2014 and 400 GWh in 2015 with incentives awarded in the year following plan achievements. PSCo is able to earn \$5 million upon reaching its annual savings goal along with an incentive on five percent of net economic benefits up to a maximum annual incentive of \$30 million. For the years 2016 through 2020, the annual electric energy savings goal is 400 GWh per year with an annual spending limit of \$84.3 million.

In July 2015, the CPUC approved PSCo's 2015-2016 DSM plan:

- A 2015 DSM electric budget of \$81.6 million and a natural gas budget of \$13.1 million; and
- A 2016 DSM electric budget of \$78.7 million and a natural gas budget of \$13.6 million.

REC Sharing — In 2011, the CPUC approved margin sharing on stand-alone REC transactions at 10 percent to PSCo and 90 percent to customers for 2014. In 2012, the CPUC approved an annual margin sharing on the first \$20 million of margins on hybrid REC trades of 80 percent to the customers and 20 percent to PSCo. Margins in excess of the \$20 million are to be shared 90 percent to the customers and 10 percent to PSCo. The CPUC authorized PSCo to return to customers unspent carbon offset funds by crediting the RESA regulatory asset balance. PSCo credited to the RESA regulatory liability balance approximately \$5.5 million and \$0.6 million in 2015 and 2014, respectively. The cumulative credit to the RESA regulatory liability balance was \$110.6 million and \$105.1 million at Dec. 31, 2015 and Dec. 31, 2014, respectively. The credits include the customers' share of REC trading margins and the unspent share of carbon offset funds. The current sharing mechanism, without modification, extends through 2017.

SPS

Pending and Recently Concluded Regulatory Proceedings — PUCT

SPS – Texas 2015 Electric Rate Case — In December 2014, SPS filed a retail electric rate case in Texas seeking an overall increase in annual revenue of approximately \$64.8 million, or 6.7 percent. The filing was based on a HTY ending June 2014, adjusted for known and measurable changes, a ROE of 10.25 percent, an electric rate base of approximately \$1.6 billion and an equity ratio of 53.97 percent.

SPS requested a waiver of the PUCT post-test year adjustment rule which would allow for inclusion of \$392 million (SPS total company) additional capital investment for the period July 1, 2014 through Dec. 31, 2014. In June 2015, SPS revised its requested rate increase to \$42.1 million.

In December 2015, the PUCT made the following decisions:

- Disallowed SPS' proposed adjustment to jurisdictional allocation factors to reflect Golden Spread Electric Cooperative, Inc.'s (Golden Spread's) wholesale load reductions from 500 MW to 300 MW, effective June 1, 2015;
- Disallowed incentive compensation;
- Approved an equity ratio of 51.00 percent instead of the actual 53.97 percent; and
- A ROE of 9.70 percent.

The following table reflects the ALJs' position and PUCT's decision.

(Millions of Dollars)	ALJs' Proposal for Decision	PUCT Decision
SPS' revised rate request	\$ 42.1	\$ 42.1
Investment for capital expenditures — post-test year adjustments	(8.9)	(8.9)
Lower ROE	(6.3)	(6.3)
Lower capital structure	—	(3.7)
Annual incentive compensation	(0.2)	(0.3)
O&M expense adjustments	(4.6)	(4.6)
Depreciation expense	(2.7)	(2.7)
Property taxes	(0.9)	(0.9)
Revenue adjustments	(1.1)	(1.6)
Wholesale load reductions	—	(11.5)
SPP transmission expansion plan	(4.2)	(4.2)
Other, net	1.4	(1.2)
Total, gross of rate case expenses	\$ 14.6	\$ (3.8)
Adjustment to move rate case expenses to a separate docket	(0.2)	(0.2)
Total, net of rate case expenses	\$ 14.4	\$ (4.0)
New depreciation rates	(11.2)	(11.2)
Earnings impact	\$ 3.2	\$ (15.2)

In January 2016, SPS filed its motion for rehearing on capital structure, incentive compensation and known and measurable adjustments, including wholesale load reductions and post test-year capital additions. On Feb. 11, 2016, the PUCT orally denied requests for rehearing. SPS plans to file a second motion for rehearing within 20 days of the date of the PUCT's written order.

SPS – Texas 2016 Electric Rate Case — On Feb. 16, 2016, SPS filed a retail electric, non-fuel rate case in Texas with each of its Texas municipalities and the PUCT requesting an overall increase in annual base rate revenue of approximately \$71.9 million, or 14.4 percent. The filing is based on a HTY ended Sept. 30, 2015, a requested ROE of 10.25 percent, an electric rate base of approximately \$1.7 billion, and an equity ratio of 53.97 percent.

As part of its request, SPS included estimated information regarding increases and decreases in SPS' cost of service, including certain expenses, capital investments, cost of capital and sales for the period of Oct. 1, 2015 through Dec. 31, 2015. Subsequent to the filing, (i.e., 45 days), the estimated information will be updated to reflect actual results.

The following table summarizes the net request:

(Millions of Dollars)	Request
Capital expenditure investments	\$ 38.6
Change in jurisdictional allocation factors	10.9
Changes in ROE and capital structure	11.7
Estimated rate case expenses ^(a)	4.5
Other, net	6.2
Total	\$ 71.9

^(a) SPS anticipates rate case expenses, for this proceeding, to be separated from the request for consideration in a separate docket.

The final rates established at the end of the case will be made effective retroactive to July 20, 2016 and SPS will be entitled to collect a surcharge for usage from July 20, 2016 through the date SPS implements final rates. A PUCT decision is anticipated in the first quarter of 2017.

Pending Regulatory Proceedings — NMPRC

SPS – New Mexico 2015 Electric Rate Case — In October 2015, SPS filed a New Mexico electric rate case with the NMPRC for a net increase in base rates of approximately \$24.3 million. The proposed net amount reflects an increase in non-fuel base rates of \$45.4 million and a decrease in base fuel revenue of approximately \$21.1 million. The decrease in base fuel revenue will be reflected in adjustments collected through the fuel and purchased power adjustment clause. The rate filing is based on a June 30, 2015 HTY adjusted for known and measurable changes, a requested ROE of 10.25 percent, an electric jurisdictional rate base of approximately \$734 million and an equity ratio of 53.97 percent.

The major components of the requested rate increase are summarized below:

(Millions of Dollars)	Request
2015 base period deficiency	\$ 19.7
Capital expenditures — post-test year adjustments	12.3
Depreciation, higher rates reflecting changes in depreciable lives, interim retirements and net salvage	3.7
Transmission revenue and expense, including charges paid to SPP for construction of regionally shared transmission projects	2.0
ROE, reflecting an increase from 9.96 percent to 10.25 percent	1.6
Rider revenue adjustments - gross receipts tax	1.3
Other, net	4.8
Requested rate increase	\$ 45.4

The next steps in the procedural schedule are expected to be as follows:

- Settlement conference — Feb. 29, 2016;
- Staff and intervenor direct testimony — April 1, 2016;
- Rebuttal testimony — April 18, 2016; and
- Evidentiary hearing begins — April 28, 2016.

A NMPRC decision and implementation of final rates is anticipated in the second half of 2016.

In response to the original 2015 electric rate case previously dismissed, SPS has appealed that decision to the New Mexico Supreme Court. SPS and the NMPRC have filed a joint agreed motion to dismiss the appeal with the New Mexico Supreme Court. The motion provides for the case to be remanded to the NMPRC for entry of an order affirming SPS' right to use a FTY that begins up to 13 months after SPS files a rate case. SPS will not resume the previously dismissed rate case and will proceed with the October 2015 rate case.

Pending and Recently Concluded Regulatory Proceedings — FERC and Other

MISO ROE Complaints/ROE Adder — In November 2013, a group of customers filed a complaint at the FERC against MISO TOs, including NSP-Minnesota and NSP-Wisconsin. The complaint argued for a reduction in the ROE in transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, a prohibition on capital structures in excess of 50 percent equity, and the removal of ROE adders (including those for RTO membership and being an independent transmission company), effective Nov. 12, 2013.

Subsequently, the FERC adopted a new ROE methodology, which requires electric utilities to use a two-step discounted cash flow analysis that incorporates both short-term and long-term growth projections to estimate the cost of equity.

The ROE complaint was set for full hearing procedures. The complainants and intervenors filed testimony recommending a ROE between 8.67 percent and 9.54 percent. The FERC staff recommended a ROE of 8.68 percent. The MISO TOs recommended a ROE not less than 10.8 percent. In December 2015, an ALJ initial decision was issued recommending a ROE of 10.32 percent. Briefs on exceptions challenging the ALJ recommendation were filed in January 2016. A FERC order is expected to be issued later in 2016.

Certain MISO TOs separately requested FERC approval of a 50 basis point ROE adder for RTO membership, which was approved effective Jan. 6, 2015, subject to the outcome of the ROE complaint. The total ROE, including the RTO membership adder, may not exceed the top of the discounted cash flow range under the new ROE methodology. Certain intervenors sought rehearing of the FERC order granting the ROE adder and FERC action is pending.

In February 2015, certain intervenors filed a second complaint to reduce the MISO region ROE to 8.67 percent, prior to an adder. FERC set the second complaint for hearings, and established a refund effective date of Feb. 12, 2015. The complainants and intervenors filed direct testimony in September 2015, the MISO TOs filed answering testimony in October 2015 and FERC staff filed testimony in November 2015. In January 2016, all parties updated their ROE analyses. The complainants and intervenors recommended ROEs between 8.72 percent and 9.32 percent while FERC staff recommended a ROE of 8.78 percent. The MISO TOs recommended a ROE of 10.96 percent. Hearings were held before an ALJ in February 2016. An ALJ initial decision is expected in June 2016 with a FERC decision expected in late 2016 or 2017.

NSP-Minnesota recorded a current liability representing the current best estimate of a refund obligation associated with the new ROE, including the RTO membership adder, as of Dec. 31, 2015. The new FERC ROE methodology is estimated to reduce transmission revenue, net of expense, between \$8 million and \$10 million annually for the NSP System.

SPS – Global Settlement Agreement — In August 2015, SPS, Golden Spread, four New Mexico Cooperatives, West Texas Municipal Power Agency, Public Service Company of New Mexico (PNM) and Tri-County Electric Cooperative, Inc. filed a settlement agreement with the FERC that would provide a comprehensive resolution of nine pending matters in dispute between SPS and these wholesale production and transmission customers, including the 2013 SPS complaint orders and three pending ROE complaints. In October 2015, the FERC issued an order approving the settlement agreement. As a result of the settlement, SPS issued refunds to Golden Spread and PNM of \$49.1 million, but recognized a reversal of previously recorded reductions in revenue of approximately \$7.9 million in the fourth quarter of 2015. The settlement provides a ROE for production services of 10.0 percent and transmission services of 10.5 percent, beginning Oct. 20, 2014, and subject to a moratorium on filings for ROE changes, effective prior to Jan. 1, 2020. On Jan. 29, 2016, the FERC approved the SPS compliance filings required by the settlement and FERC order.

Sale of Texas Transmission Assets — In March 2015, SPS reached an agreement to sell certain segments of SPS' transmission lines to Oncor Electric Delivery Company LLC. In November 2015, the transaction closed with the required regulatory approvals and SPS recognized a \$3.9 million pre-tax gain after the impacts of sharing with Texas retail customers.

SPP Open Access Transmission Tariff (OATT) Upgrade Costs — Under the SPP OATT, costs of participant-funded transmission upgrades may be recovered, in part, from other SPP customers whose transmission service is dependent upon capacity enabled by the upgrades. To date, SPP has not charged its customers any amounts attributable to these upgrades. SPP recently indicated it may attempt to quantify and assess charges beginning in late 2016, including amounts for prior periods. Due to the limited information available and lack of historical precedent, the potential loss, if any, is not currently estimable. No accrual has been recorded for this matter.

13. Commitments and Contingencies

Commitments

Capital Commitments — Xcel Energy has made commitments in connection with a portion of its projected capital expenditures. Xcel Energy's capital commitments primarily relate to the following major projects:

PSCo Gas Transmission Integrity Management Programs — PSCo is proactively identifying and addressing the safety and reliability of natural gas transmission pipelines. The pipeline integrity efforts include primarily pipeline assessment and maintenance projects.

PSCo Electric Distribution Integrity Management Programs — PSCo is assessing aging infrastructure for distribution assets and replacing worn components to increase system performance.

SPS Transmission NTC — SPS has accepted NTCs for several hundred miles of transmission line and related substation projects based on needs identified through SPP's various planning processes, including those associated with economics, reliability, generator interconnection or the load addition processes. Most significant are the 345 KV transmission line from TUCO to Yoakum County to Hobbs Plant and the Hobbs Plant to China Draw 345 KV transmission line.

Fuel Contracts — Xcel Energy has entered into various long-term commitments for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2016 and 2060. Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements.

The estimated minimum purchases for Xcel Energy under these contracts as of Dec. 31, 2015 are as follows:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2016.....	\$ 824.4	\$ 112.2	\$ 285.4	\$ 282.0
2017.....	483.0	112.3	132.2	254.9
2018.....	227.8	62.7	181.0	154.5
2019.....	42.7	124.1	187.6	113.8
2020.....	44.4	46.9	203.4	101.6
Thereafter.....	334.9	599.2	409.5	1,044.2
Total.....	<u>\$ 1,957.2</u>	<u>\$ 1,057.4</u>	<u>\$ 1,399.1</u>	<u>\$ 1,951.0</u>

Additional expenditures for fuel and natural gas storage and transportation will be required to meet expected future electric generation and natural gas needs. Xcel Energy's risk of loss, in the form of increased costs from market price changes in fuel, is mitigated through the use of natural gas and energy cost-rate adjustment mechanisms, which provide for pass-through of most fuel, storage and transportation costs to customers.

PPAs — NSP Minnesota, PSCo and SPS have entered into PPAs with other utilities and energy suppliers with expiration dates through 2039 for purchased power to meet system load and energy requirements and meet operating reserve obligations. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts also contain minimum energy purchase commitments. Capacity and energy payments are typically contingent on the independent power producing entity meeting certain contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of \$230.6 million, \$229.8 million and \$217.0 million in 2015, 2014 and 2013, respectively. At Dec. 31, 2015, the estimated future payments for capacity and energy that the utility subsidiaries of Xcel Energy are obligated to purchase pursuant to these executory contracts, subject to availability, are as follows:

(Millions of Dollars)	Capacity	Energy ^(a)
2016.....	\$ 191.0	\$ 106.9
2017.....	165.8	91.8
2018.....	129.1	93.2
2019.....	83.6	98.7
2020.....	68.1	105.4
Thereafter.....	362.5	662.5
Total.....	<u>\$ 1,000.1</u>	<u>\$ 1,158.5</u>

(a) Excludes contingent energy payments for renewable energy PPAs.

Additional energy payments under these PPAs and PPAs accounted for as operating leases will be required to meet expected future electric demand.

Leases — Xcel Energy leases a variety of equipment and facilities used in the normal course of business. Three of these leases qualify as capital leases and are accounted for accordingly. The assets and liabilities at the inception of a capital lease are recorded at the lower of fair market value or the present value of future lease payments and are amortized over the term of the contract.

WYCO was formed as a joint venture with CIG to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy Inc. has a 50 percent ownership interest in WYCO. WYCO generally leases its facilities to CIG, and CIG operates the facilities, providing natural gas storage services to PSCo under separate service agreements.

PSCo accounts for its Totem natural gas storage service arrangement with CIG as a capital lease. As a result, PSCo had \$132.9 million and \$138.9 million of capital lease obligations recorded for the arrangement as of Dec. 31, 2015 and 2014, respectively. Xcel Energy Inc. eliminates 50 percent of the capital lease obligation related to WYCO in the consolidated balance sheet along with an equal amount of Xcel Energy Inc.'s equity investment in WYCO.

PSCo records amortization for its capital leases as cost of natural gas sold and transported on the consolidated statements of income. Total amortization expenses under capital lease assets were approximately \$8.2 million, \$7.2 million and \$6.3 million for 2015, 2014 and 2013, respectively. Following is a summary of property held under capital leases:

(Millions of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Gas storage facilities	\$ 200.5	\$ 200.5
Gas pipeline	20.7	20.7
Property held under capital leases	221.2	221.2
Accumulated depreciation	(57.2)	(49.0)
Total property held under capital leases, net	<u>\$ 164.0</u>	<u>\$ 172.2</u>

The remainder of the leases, primarily for office space, railcars, generating facilities, trucks, aircraft, cars and power-operated equipment, are accounted for as operating leases. Total expenses under operating lease obligations for Xcel Energy were approximately \$265.3 million, \$271.9 million and \$242.1 million for 2015, 2014 and 2013, respectively. These expenses include capacity payments for PPAs accounted for as operating leases of \$223.6 million, \$228.2 million and \$197.7 million in 2015, 2014 and 2013, respectively, recorded to electric fuel and purchased power expenses.

Included in the future commitments under operating leases are estimated future capacity payments under PPAs that have been accounted for as operating leases in accordance with the applicable accounting guidance.

Future commitments under operating and capital leases are:

(Millions of Dollars)	Operating Leases	PPA ^{(a) (b)} Operating Leases	Total Operating Leases	Capital Leases
2016	\$ 24.6	\$ 217.0	\$ 241.6	\$ 17.1
2017	22.0	208.7	230.7	15.1
2018	21.5	210.0	231.5	14.7
2019	25.9	227.8	253.7	14.5
2020	20.8	241.3	262.1	14.3
Thereafter	175.0	2,135.2	2,310.2	258.8
Total minimum obligation				334.5
Interest component of obligation				(236.9)
Present value of minimum obligation				<u>\$ 97.6</u> ^(c)

(a) Amounts do not include PPAs accounted for as executory contracts.

(b) PPA operating leases contractually expire through 2039.

(c) Future commitments exclude certain amounts related to Xcel Energy's 50 percent ownership interest in WYCO.

Variable Interest Entities — The accounting guidance for consolidation of variable interest entities requires enterprises to consider the activities that most significantly impact an entity's financial performance, and power to direct those activities, when determining whether an enterprise is a variable interest entity's primary beneficiary.

PPAs — Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from independent power producing entities for which the utility subsidiaries are required to reimburse natural gas or biomass fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. These specific PPAs create a variable interest in the independent power producing entity.

Xcel Energy has determined that certain independent power producing entities are variable interest entities. Xcel Energy is not subject to risk of loss from the operations of these entities, and no significant financial support has been, or is required to be provided other than contractual payments for energy and capacity set forth in the PPAs.

Xcel Energy has evaluated each of these variable interest entities for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities. Xcel Energy has concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. Xcel Energy's utility subsidiaries had approximately 3,698 MW of capacity under long-term PPAs as of Dec. 31, 2015, and 2014 with entities that have been determined to be variable interest entities. These agreements have expiration dates through 2033.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk electric generating stations from TUCO under contracts for those facilities that expire in December 2016 and December 2017, respectively. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing, and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers.

No significant financial support has been, or is required to be provided to TUCO by SPS, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of certain fuel procurement costs. SPS has determined that TUCO is a variable interest entity. SPS has concluded that it is not the primary beneficiary of TUCO because SPS does not have the power to direct the activities that most significantly impact TUCO's economic performance.

Low-Income Housing Limited Partnerships — Eloigne and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy Inc. has determined Eloigne and NSP-Wisconsin's low-income housing limited partnerships to be variable interest entities primarily due to contractual arrangements within each limited partnership that establish sharing of ongoing voting control and profits and losses that does not consistently align with the partners' proportional equity ownership. These limited partnerships are designed to qualify for low-income housing tax credits. Eloigne and NSP-Wisconsin generally receive a larger allocation of the tax credits than the general partners at inception of the arrangements. Xcel Energy Inc. has determined that Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance, and therefore Xcel Energy Inc. consolidates these limited partnerships in its consolidated financial statements.

Equity financing for these entities has been provided by Eloigne, NSP-Wisconsin and the general partner of each limited partnership. Xcel Energy's risk of loss is limited to its capital contributions, adjusted for any distributions and its share of undistributed profits and losses; no significant additional financial support has been, or is required to be provided to the limited partnerships by Eloigne or NSP-Wisconsin. Mortgage-backed debt typically comprises the majority of the financing at inception of each limited partnership and is paid over the life of the limited partnership arrangement. Obligations of the limited partnerships are generally secured by the housing properties of each limited partnership, and the creditors of each limited partnership have no significant recourse to Xcel Energy Inc. or its subsidiaries. Likewise, the assets of the limited partnerships may only be used to settle obligations of the limited partnerships, and not those of Xcel Energy Inc. or its subsidiaries.

Amounts reflected in Xcel Energy's consolidated balance sheets for the Eloigne and NSP-Wisconsin low-income housing limited partnerships include the following:

(Thousands of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Current assets	\$ 6,274	\$ 6,609
Property, plant and equipment, net.	51,480	53,047
Other noncurrent assets	1,394	1,503
Total assets.	<u>\$ 59,148</u>	<u>\$ 61,159</u>
Current liabilities	\$ 7,540	\$ 7,774
Mortgages and other long-term debt payable.	31,082	31,207
Other noncurrent liabilities.	644	619
Total liabilities	<u>\$ 39,266</u>	<u>\$ 39,600</u>

Technology Agreements — Xcel Energy has a contract that extends through December 2019 with International Business Machines Corp. (IBM) for information technology services. The contract is cancelable at Xcel Energy's option, although Xcel Energy would be obligated to pay 50 percent of the contract value for early termination. Xcel Energy capitalized or expensed \$109.5 million, \$111.3 million and \$90.3 million associated with the IBM contract in 2015, 2014 and 2013, respectively.

Xcel Energy's contract with Accenture for information technology services extends through December 2020. The contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. Xcel Energy capitalized or expensed \$17.3 million, \$27.3 million and \$23.7 million associated with the Accenture contract in 2015, 2014 and 2013, respectively.

Committed minimum payments under these obligations are as follows:

(Millions of Dollars)	IBM Agreement	Accenture Agreement
2016	\$ 34.4	\$ 10.0
2017	34.4	10.5
2018	33.5	10.7
2019	33.5	10.8
2020	—	11.0
Thereafter	—	—

Guarantees and Indemnifications

Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities under specified agreements or transactions. The guarantees and bond indemnities issued by Xcel Energy Inc. guarantee payment or performance by its subsidiaries. As a result, Xcel Energy Inc.'s exposure under the guarantees and bond indemnities is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries limit the exposure to a maximum amount stated in the guarantees and bond indemnities. As of Dec. 31, 2015 and 2014, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

Guarantees and Surety Bonds

The following table presents guarantees and bond indemnities issued and outstanding as of Dec. 31, 2015:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of customer loans for the Farm Rewiring Program ^(a) .	NSP-Wisconsin	\$ 1.0	\$ 0.1	(e)
Guarantee of the indemnification obligations of Xcel Energy Services Inc. under the aircraft leases ^(b)	Xcel Energy Inc.	6.7	—	(f)
Guarantee of residual value of assets under the Bank of Tokyo-Mitsubishi Capital Corporation Equipment Leasing Agreement ^(c)	NSP-Minnesota	4.8	—	(g)
Total guarantees issued		<u>\$ 12.5</u>	<u>\$ 0.1</u>	
Guarantee performance and payment of surety bonds for Xcel Energy Inc.'s utility subsidiaries ^(d)	Xcel Energy Inc.	\$ 41.3	(i)	(h)

(a) The term of this guarantee expires in 2020, which is the final scheduled repayment date for the loans. As of Dec. 31, 2015, no claims had been made by the lender.

(b) The term of this guarantee expires in 2017 when the associated leases expire.

(c) The terms of this guarantee expires in 2019 when the associated lease expires.

(d) The surety bonds primarily relate to workers compensation benefits and utility projects. The workers compensation bonds are renewed annually and the project based bonds expire in conjunction with the completion of the related projects.

(e) The debtor becomes the subject of bankruptcy or other insolvency proceedings.

(f) Nonperformance and/or nonpayment.

(g) Actual fair value of leased assets is less than the guaranteed residual value amount at the end of the lease term.

(h) Failure of any one of Xcel Energy Inc.'s utility subsidiaries to perform under the agreement that is the subject of the relevant bond. In addition, per the indemnity agreement between Xcel Energy Inc. and the various surety companies, the surety companies have the discretion to demand that collateral be posted.

(i) Due to the magnitude of projects associated with the surety bonds, the total current exposure of this indemnification cannot be determined. Xcel Energy Inc. believes the exposure to be significantly less than the total amount of the outstanding bonds.

Indemnification Agreements

Xcel Energy Inc. and its subsidiaries provide indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, as well as breaches of representations and warranties, including corporate existence, transaction authorization and income tax matters with respect to assets sold. Xcel Energy Inc.'s and its subsidiaries' obligations under these agreements may be limited in terms of duration and amount. The maximum potential amount of future payments under these indemnifications cannot be reasonably estimated as the obligated amounts of these indemnifications often are not explicitly stated.

Environmental Contingencies

Xcel Energy has been or is currently involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, the subsidiary involved believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, the subsidiary involved is pursuing, or intends to pursue, recovery from other PRPs and through the regulated rate process. New and changing federal and state environmental mandates can also create added financial liabilities for Xcel Energy, which are normally recovered through the regulated rate process. To the extent any costs are not recovered through the options listed above, Xcel Energy would be required to recognize an expense.

Site Remediation — Various federal and state environmental laws impose liability, without regard to the legality of the original conduct, where hazardous substances or other regulated materials have been released to the environment. Xcel Energy Inc.'s subsidiaries may sometimes pay all or a portion of the cost to remediate sites where past activities of their predecessors or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs operated by Xcel Energy Inc.'s subsidiaries or their predecessors, or other entities; and third-party sites, such as landfills, for which one or more of Xcel Energy Inc.'s subsidiaries are alleged to be a PRP that sent wastes to that site.

MGP Sites

Ashland MGP Site — NSP-Wisconsin has been named a PRP for contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (the Site) includes property owned by NSP-Wisconsin, previously operated by a MGP facility (the Upper Bluff), and two other properties: an adjacent city lakeshore park area (Kreher Park); and an area of Lake Superior's Chequamegon Bay adjoining the park (the Sediments).

In 2010, the EPA issued its Record of Decision (ROD), including their preferred remedy for the Sediments which is a hybrid remedy involving both dry excavation and wet conventional dredging methodologies (the Hybrid Remedy). A wet conventional dredging only remedy (the Wet Dredge), contingent upon the completion of a successful Wet Dredge pilot study, is another possibility.

In 2012, under a settlement agreement, NSP-Wisconsin agreed to perform the remediation of the Phase I Project Area (which includes the Upper Bluff and Kreher Park areas of the Site). Fieldwork began in 2012 and continues. Excavation and containment remedies are complete. A long-term groundwater pump and treatment program is now underway. The final design was approved by the EPA in late 2015. The current cost estimate for the cleanup of the Phase I Project Area is approximately \$65 million, of which approximately \$47 million has already been spent.

Negotiations are ongoing between the EPA and NSP-Wisconsin regarding who will pay for or perform the cleanup of the Sediments and which remedy will be implemented. The EPA's ROD includes estimates that the cost of the Hybrid Remedy is between \$63 million and \$77 million, with a potential deviation in such estimated costs of up to 50 percent higher to 30 percent lower. NSP-Wisconsin believes the Hybrid Remedy is not safe or feasible to implement. In 2015, NSP-Wisconsin constructed a breakwater at the site to serve as wave attenuation and containment for a wet dredge pilot study and full scale sediment remedy at the site. The wet dredge pilot study is anticipated to commence in spring 2016.

As a result of litigation and settlements approved by the U.S. District Court for the Western District of Wisconsin in 2015, three other PRPs have contributed \$15.9 million to the remediation of the site. Settlements in principle were also reached with the City of Ashland and the County of Ashland in January 2016, and NSP-Wisconsin anticipates that its litigation efforts against other PRPs are complete.

At Dec. 31, 2015 and 2014, NSP-Wisconsin had recorded a liability of \$94.4 million and \$107.6 million, respectively, for the Site based upon potential remediation and design costs together with estimated outside legal and consultant costs; of which \$17.0 million and \$28.9 million, respectively, was considered a current liability. NSP-Wisconsin's potential liability, the actual cost of remediation and the time frame over which the amounts may be paid are subject to change. NSP-Wisconsin also continues to work to identify and access state and federal funds to apply to the ultimate remediation cost of the entire site. Unresolved issues or factors that could result in higher or lower NSP-Wisconsin remediation costs for the Site include the cleanup approach implemented for the Sediments, which party implements the cleanup, the timing of when the cleanup is implemented and whether federal or state funding may be directed to help offset remediation costs at the Site.

NSP-Wisconsin has deferred the estimated site remediation costs as a regulatory asset. The PSCW has consistently authorized NSP-Wisconsin rate recovery for all remediation costs incurred at the Site. In a December 2012 decision, the PSCW agreed to allow NSP-Wisconsin to pre-collect certain costs, to amortize costs over a ten-year period, and to apply a three percent carrying cost to the unamortized regulatory asset. In December 2015, the PSCW approved NSP-Wisconsin's 2016 rate case request for an increase to the annual recovery for MGP clean-up costs from \$4.7 million to \$7.6 million.

Fargo, N.D. MGP Site — In May 2015, in connection with a city water main replacement and street improvement project in Fargo, N.D., underground pipes, tars and impacted soils, which may be related to a former MGP site operated by NSP-Minnesota or a prior company, were discovered. After initial reports and discussions with the City of Fargo and the North Dakota Department of Health, NSP-Minnesota removed the impacted soils and other materials from the project area. NSP-Minnesota is undertaking further investigation of the location of the historic MGP site and nearby properties. At this time, NSP-Minnesota's investigation of the site is preliminary as information is still being gathered. In October 2015, NSP-Minnesota initiated insurance recovery litigation in North Dakota. The U.S. District Court for the District of North Dakota will likely establish a scheduling order for the case in the first quarter of 2016.

As of Dec. 31, 2015, NSP-Minnesota had recorded a liability of \$2.7 million related to further investigation and additional planned activities. Uncertainties include the nature and cost of the additional remediation efforts that may be necessary, the ability to recover costs from insurance carriers and the potential for contributions from entities that may be identified as PRPs. Therefore, the total cost of remediation, NSP-Minnesota's potential liability and amounts allocable to the North Dakota and Minnesota jurisdictions related to the site cannot currently be reasonably estimated. In July 2015, NSP-Minnesota filed a request with the NDPSRC for approval to initially defer the portion of investigation and response costs allocable to the North Dakota jurisdiction. In December 2015, the NDPSRC approved NSP-Minnesota's request.

Other MGP Sites — Xcel Energy is currently involved in investigating and/or remediating several other MGP sites where regulated materials may have been deposited. Xcel Energy has identified seven sites across all of its service territories where former MGP activities have or may have resulted in site contamination and are under current investigation and/or remediation. At some or all of these MGP sites, there are other parties that may have responsibility for some portion of any remediation. Xcel Energy anticipates that the majority of the remediation at these sites will continue through at least 2016. Xcel Energy had accrued \$2.1 million for all of these sites at Dec. 31, 2015 and 2014, respectively. There may be insurance recovery and/or recovery from other PRPs that will offset any costs incurred. Xcel Energy anticipates that any amounts spent will be fully recovered from customers.

Environmental Requirements

Water and Waste

Asbestos Removal — Some of Xcel Energy's facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or removed. Xcel Energy has recorded an estimate for final removal of the asbestos as an ARO. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is not expected to be material and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Federal Clean Water Act (CWA) Effluent Limitations Guidelines (ELG) — In September 2015, the EPA issued a final ELG rule for power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. Xcel Energy estimates that the cost to comply with the new ELG rule for Colorado will range from \$9 million to \$21 million, and could change as Xcel Energy continues to assess alternate compliance technologies. Xcel Energy is in the process of evaluating whether the costs of compliance at NSP-Minnesota and NSP-Wisconsin could have a material impact on the results of operations, financial position or cash flows. The anticipated costs of compliance with the final rule at SPS are not expected to have a material impact on the results of operations, financial position or cash flows. Xcel Energy believes that compliance costs would be recoverable through regulatory mechanisms.

Federal CWA Section 316(b) — Section 316(b) of the federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse environmental impacts to aquatic species. The EPA published the final 316(b) rule in August 2014. The rule prescribes technology for protecting fish that get stuck on plant intake screens (known as impingement) and describes a process for site-specific determinations by each state for sites that must protect the small aquatic organisms that pass through the intake screens into the plant cooling systems (known as entrainment). For Xcel Energy, these requirements will primarily impact plants within the NSP-Minnesota service territory. The timing of compliance with the requirements will vary from plant-to-plant since the new rule does not have a final compliance deadline. Xcel Energy estimates the likely cost for complying with impingement requirements may be incurred between 2016 and 2027 and is approximately \$49 million with the majority needed for NSP-Minnesota. Xcel Energy believes at least six NSP-Minnesota plants and two NSP-Wisconsin plants could be required by state regulators to make improvements to reduce entrainment. The exact cost of the entrainment improvements is uncertain, but could be up to \$194 million depending on the outcome of certain entrainment studies and cost-benefit analyses. Xcel Energy anticipates these costs will be fully recoverable in rates.

Federal CWA Waters of the United States Rule — In June 2015, the EPA and the U.S. Army Corps of Engineers published a final rule that significantly expands the types of water bodies regulated under the CWA and broadens the scope of waters subject to federal jurisdiction. The expansion of the term “Waters of the U.S.” will subject more utility projects to federal CWA jurisdiction, thereby potentially delaying the siting of new generation projects, pipelines, transmission lines and distribution lines, as well as increasing project costs and expanding permitting and reporting requirements. The rule went into effect in August 2015. In October 2015, the U.S. Court of Appeals for the Sixth Circuit issued a nationwide stay of the final rule, pending further legal proceedings.

Air

GHG Emission Standard for Existing Sources (Clean Power Plan or CPP) — In October 2015, a final rule was published by the EPA for GHG emission standards for existing power plants. States must develop implementation plans by September 2016, with the possibility of an extension to September 2018, or the EPA will prepare a federal plan for the state. Among other things, the rule requires that state plans include enforceable measures to ensure emissions from existing power plants achieve the EPA’s state-specific interim (2022-2029) and final (2030 and thereafter) emission performance targets. The CPP is currently being challenged by multiple parties in the D.C. Circuit Court. In January 2016, the D.C. Circuit Court denied requests to stay the effectiveness of the rule as well as ordered expedited review of the CPP, with briefings to be completed and oral arguments held by June 2016. Following the D.C. Circuit Court’s denial of motions for stay, multiple parties filed requests for stay with the U.S. Supreme Court. In February 2016, the U.S. Supreme Court issued an order staying the final CPP rule. The stay will remain in effect until, first, the D.C. Circuit Court and then the U.S. Supreme Court have ruled on the challenges to the CPP.

Xcel Energy has undertaken a number of initiatives that reduce GHG emissions and respond to state renewable and energy efficiency goals. The CPP could require additional emission reductions in states in which Xcel Energy operates. If state plans do not provide credit for the investments we have already made to reduce GHG emissions, or if they require additional initiatives or emission reductions, then their requirements would potentially impose additional substantial costs. Until Xcel Energy has more information about SIPs or knows the requirements of the EPA’s upcoming final rule on federal plans for the states that do not develop related plans, Xcel Energy cannot predict the costs of compliance with the final rule once it takes effect. Xcel Energy believes compliance costs will be recoverable through regulatory mechanisms. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the CPP or cost recovery is not provided in a timely manner, it could have a material impact on results of operations, financial position or cash flows.

CSAPR — CSAPR addresses long range transport of PM and ozone by requiring reductions in SO₂ and NO_x from utilities in the eastern half of the United States using an emissions trading program. For Xcel Energy, the rule applies in Minnesota, Wisconsin and Texas. CSAPR compliance in 2015 did not and 2016 is not expected to have a material impact on the results of operations, financial position or cash flows.

CSAPR was adopted to address interstate emissions impacting downwind states’ attainment of the 1997 ozone NAAQS and the 1997 and 2006 particulate NAAQS. As the EPA revises the NAAQS, it will consider whether to make any further reductions to CSAPR emission budgets and whether to change which states are included in the emissions trading program. In December 2015, the EPA proposed adjustments to CSAPR emission budgets which address attainment of the more stringent 2008 ozone NAAQS. If adopted as proposed, the ozone season emission budget for NO_x in Texas would be reduced by approximately 14 percent, which may lead to increased cost to purchase emission allowances.

Regional Haze Rules — The regional haze program is designed to address widespread haze that results from emissions from a multitude of sources. In 2005, the EPA amended the BART requirements of its regional haze rules, which require the installation and operation of emission controls for industrial facilities emitting air pollutants that reduce visibility in certain national parks and wilderness areas. In their first regional haze SIPs, Colorado, Minnesota and Texas identified the Xcel Energy facilities that will have to reduce SO₂, NO_x and PM emissions under BART and set emissions limits for those facilities.

PSCo

In 2011, the Colorado Air Quality Control Commission approved a SIP (the Colorado SIP) that included the CACJA emission reduction plan as satisfying regional haze requirements for facilities included within the CACJA plan. In addition, the Colorado SIP included a BART determination for Comanche Units 1 and 2. The EPA approved the Colorado SIP in 2012. Emission controls at Hayden Unit 1 were placed into service in November 2015 and Hayden Unit 2 is expected to be placed into service in late 2016, at an estimated combined cost of \$75.2 million, completing the pollution control equipment required on PSCo plants under the CACJA. PSCo anticipates these costs will be fully recoverable through regulatory mechanisms.

NSP-Minnesota

In 2009, the Minnesota Pollution Control Agency (MPCA) approved a SIP (the Minnesota SIP) and submitted it to the EPA for approval. The MPCA's source-specific BART limits for Sherco Units 1 and 2 require combustion controls for NO_x and scrubber upgrades for SO₂. The MPCA supplemented its Minnesota SIP in 2012, determining that CSAPR meets BART requirements, but also implementing its source-specific BART determination for Sherco Units 1 and 2 from the 2009 Minnesota SIP. In June 2012, the EPA approved the Minnesota SIP for EGUs and also approved the source-specific emission limits for Sherco Units 1 and 2. The combustion controls were installed first and the scrubber upgrades were completed in December 2014, at a cost of \$46.9 million. NSP-Minnesota has included these costs for recovery in rate proceedings.

In August 2012, the National Parks Conservation Association, Sierra Club, Voyageurs National Park Association, Friends of the Boundary Waters Wilderness, Minnesota Center for Environmental Advocacy and Fresh Energy appealed the EPA's approval of the Minnesota SIP to the U.S. Court of Appeals for the Eighth Circuit (Eighth Circuit). In June 2013, the Eighth Circuit ordered this case to be held in abeyance until the U.S. Supreme Court decided the CSAPR case. In January 2016, the Eighth Circuit issued their opinion which upheld the EPA's approval of the Minnesota SIP.

SPS

Harrington Units 1 and 2 are potentially subject to BART. Texas developed a SIP (the Texas SIP) that finds the CAIR equal to BART for EGUs. As a result, no additional controls beyond CAIR compliance would be required. In May 2012, the EPA deferred its review of the Texas SIP in its final rule allowing states to find that CSAPR compliance meets BART requirements for EGUs. In December 2014, the EPA proposed to approve the BART portion of the Texas SIP, with the exception that the EPA would substitute CSAPR compliance for Texas' reliance on CAIR. In January 2016, the EPA adopted a final rule that defers its approval of CSAPR compliance as BART until the EPA considers further adjustments to CSAPR emission budgets in relation to the 2012 particle NAAQS.

In May 2014, the EPA issued a request for information under the CAA related to SO₂ control equipment at Tolk Units 1 and 2. In December 2014, the EPA proposed to disapprove the reasonable progress portions of the Texas SIP and instead adopt a FIP. The EPA proposed to require dry scrubbers on both Tolk units to reduce SO₂ emissions to help achieve reasonable progress goals for Texas and Oklahoma national parks and wilderness areas. In January 2016, the EPA adopted a final rule establishing a FIP for the state of Texas. As part of this final rule, the EPA imposed SO₂ emission limitations that reflect the installation of dry scrubbers on Tolk Units 1 and 2, with compliance required by February 2021. Investment costs associated with dry scrubbers could be approximately \$600 million. SPS plans to appeal the EPA's decision. SPS believes these costs would be recoverable through regulatory mechanisms if required, and therefore does not expect a material impact on results of operations, financial position or cash flows.

Reasonably Attributable Visibility Impairment (RAVI) — RAVI is intended to address observable impairment from a specific source such as distinct, identifiable plumes from a source's stack to a national park. In 2009, the DOI certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from NSP-Minnesota's Sherco Units 1 and 2.

In December 2012, a lawsuit against the EPA was filed in the U.S. District Court for the District of Minnesota (Minnesota District Court) by the following organizations: National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyageurs National Park Association, Fresh Energy and Sierra Club.

In May 2015, NSP-Minnesota, the EPA and the six environmental advocacy organizations filed a settlement agreement in the Minnesota District Court. The agreement anticipates a federal rulemaking that would impose stricter SO₂ emission limits on Sherco Units 1, 2 and 3, without making a RAVI attribution finding or a RAVI BART determination. The emission limits for Units 1 and 2 reflect the success of a recently completed control project. The Unit 3 emission limits will be met through changes in the operation of the existing scrubber. The Minnesota District Court issued an order staying the litigation for the time needed to complete the actions required by the settlement agreement. The plaintiffs agreed to withdraw their complaint with prejudice when those actions are completed. Plaintiffs also agreed not to request a RAVI certification for Sherco Units 1, 2 and/or 3 in the future.

After a public comment period, the EPA notified the Minnesota District Court, in July 2015, that the settlement agreement is final. The EPA has seven months to recommend and adopt a rule which will set the agreed-upon SO₂ emissions. In October 2015, the EPA proposed a rule that would set the agreed-upon SO₂ emission limits. No public comments were received on this proposal. A final rule is anticipated in March 2016. NSP-Minnesota does not anticipate the costs of compliance with the proposed settlement will have a material impact on the results of operations, financial position or cash flows.

Implementation of the NAAQS for SO₂ — The EPA adopted a more stringent NAAQS for SO₂ in 2010. In 2013, the EPA designated areas as not attaining the revised NAAQS, which did not include any areas where Xcel Energy operates power plants. However, many other areas of the country were unable to be classified by the EPA due to a lack of air monitors.

Following a lawsuit alleging that the EPA had not completed its area designations in the time required by the CAA and under a consent decree the EPA is requiring states to evaluate areas in three phases. The first phase includes areas near PSCo's Pawnee plant and SPS' Tolk and Harrington plants. The Pawnee plant recently installed an SO₂ scrubber and the Tolk and Harrington Plants utilize low sulfur coal to reduce SO₂ emissions. The Colorado Department of Health and Environment along with the Texas Commission on Environmental Quality (TCEQ) made recommendations for unclassified and nonattainment areas to the EPA in September 2015. The EPA's final decision is expected by summer 2016.

If an area is designated nonattainment, the respective states will need to evaluate all SO₂ sources in the area. The state would then submit an implementation plan for the respective areas which would be due in 18 months, designed to achieve the NAAQS within five years. The TCEQ could require additional SO₂ controls on one or more of the units at Tolk and Harrington. It is anticipated the areas near the remaining Xcel Energy power plants would be evaluated in the next designation phase, ending December 2017. Xcel Energy cannot evaluate the impacts of this ruling until the designation of nonattainment areas is made and any required state plans are developed. Xcel Energy believes that, should SO₂ control systems be required for a plant, compliance costs will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial position or cash flows.

Revisions to the NAAQS for Ozone — In October 2015, the EPA revised the NAAQS for ozone by lowering the eight-hour standard from 75 parts per billion (ppb) to 70 ppb. In areas where Xcel Energy operates, current monitored air quality concentrations comply with the new standard in the Twin Cities Metropolitan Area in Minnesota and meet the 70 ppb level in the Texas panhandle. In documents issued with the new standard, the EPA projects that both areas will meet the new standard. Current monitored air quality concentrations in areas of Wisconsin, where Xcel Energy operates, are also below the new standard. The Denver Metropolitan Area is currently not meeting the prior ozone standard and will therefore not meet the new, more stringent, standard. If not in attainment, impacted areas would study the sources of nonattainment and make emission reduction plans to attain the new standards. These plans would be due to the EPA in 2020. In conjunction with the CACJA, Xcel Energy has or plans to shut down coal-fired plants in the Denver area, has installed NO_x controls on Pawnee and Hayden Unit 1 and will finish installing NO_x controls on Hayden Unit 2 in late 2016. The final designation of nonattainment areas will be made in late 2017 based on air quality data years 2014 through 2016. Xcel Energy cannot evaluate the impacts of this ruling in Colorado until the designation of nonattainment areas is made and any required state plan has been developed. Xcel Energy believes that, should NO_x control systems be required for a plant, compliance costs will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial position or cash flows.

NSP-Minnesota NOV — In 2011, NSP-Minnesota received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the CAA at the Sherco plant and Black Dog plant in Minnesota. The NOV alleges that various maintenance, repair and replacement projects at the plants in the mid-2000s should have required a permit under the NSR process. NSP-Minnesota believes it has acted in full compliance with the CAA and NSR process. NSP-Minnesota also believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. NSP-Minnesota disagrees with the assertions contained in the NOV and intends to vigorously defend its position. It is not known whether any costs would be incurred as a result of this NOV.

Asset Retirement Obligations

Recorded AROs — AROs have been recorded for property related to the following: electric production (nuclear, steam, wind, other and hydro), electric distribution and transmission, natural gas production, natural gas transmission and distribution, and general property. The electric production obligations include asbestos, ash-containment facilities, radiation sources, storage tanks, control panels and decommissioning. The asbestos recognition associated with electric production includes certain plants at NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. NSP-Minnesota also recognized asbestos obligations for its general office building. AROs also have been recorded for NSP-Minnesota, NSP-Wisconsin, PSCo and SPS steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. NSP-Minnesota and PSCo have also recorded AROs for the retirement and removal of assets at certain wind production facilities for which the land is leased and removal is required by contract.

Xcel Energy has recognized an ARO for the retirement costs of natural gas mains and lines at NSP-Minnesota, NSP-Wisconsin and PSCo and an ARO for the retirement of above ground gas gathering, extraction and wells related to gas storage facilities at PSCo. In addition, an ARO was recognized for the removal of electric transmission and distribution equipment at NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, which consists of many small potential obligations associated with PCBs, mineral oil, storage tanks, lithium batteries, mercury and street lighting lamps. The electric and common general AROs include small obligations related to storage tanks, radiation sources and office buildings.

In April 2015, the EPA published the final rule regulating the management and disposal of coal combustion byproducts (e.g., coal ash) as a nonhazardous waste to the Federal Register. The rule became effective in October 2015. The estimated costs to comply with the final rule were incorporated into the cash flow revisions in 2015.

For the nuclear assets, the ARO is associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and PI. See Note 14 for further discussion of nuclear obligations.

A reconciliation of Xcel Energy's AROs for the years ended Dec. 31, 2015 and 2014 is as follows:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2015	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions ^(b)	Ending Balance Dec. 31, 2015
Electric plant						
Nuclear production decommissioning	\$2,037,947	\$ —	\$ —	\$ 103,077	\$ —	\$ 2,141,024
Steam and other production ash containment	127,600	—	—	4,746	(759)	131,587
Steam and other production asbestos	69,698	3,875	—	3,670	7,248	84,491
Wind production	38,260	31,085 ^(a)	—	1,778	523	71,646
Electric distribution	12,593	—	—	463	131	13,187
Other	4,605	127	(273)	178	(94)	4,543
Natural gas plant						
Gas transmission and distribution	149,964	—	—	5,969	—	155,933
Other	3,925	—	—	155	(114)	3,966
Common and other property						
Common general plant asbestos	505	—	—	27	19	551
Common miscellaneous	1,534	—	—	56	44	1,634
Total liability	<u>\$2,446,631</u>	<u>\$ 35,087</u>	<u>\$ (273)</u>	<u>\$ 120,119</u>	<u>\$ 6,998</u>	<u>\$ 2,608,562</u>

(a) The liability recognized relates to the NSP-Minnesota Pleasant Valley and Border Wind Farms which were placed in service during 2015.

(b) In 2015, AROs were revised for changes in estimated cash flows and the timing of those cash flows. Changes in the asbestos AROs were mainly related to updated cost estimates.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$1.7 billion as of Dec. 31, 2015, consisting of external investment funds.

(Thousands of Dollars)	Beginning Balance Jan. 1, 2014	Liabilities Recognized	Accretion	Cash Flow Revisions ^(a)	Ending Balance Dec. 31, 2014 ^(b)
Electric plant					
Nuclear production decommissioning	\$ 1,628,298	\$ —	\$ 86,284	\$ 323,365	\$ 2,037,947
Steam and other production ash containment	79,353	—	3,354	44,893	127,600
Steam and other production asbestos	50,827	747	2,972	15,152	69,698
Wind production	37,464	—	1,676	(880)	38,260
Electric distribution	12,186	—	444	(37)	12,593
Other	3,551	705	137	212	4,605
Natural gas plant					
Gas transmission and distribution	1,198	20,935	76	127,755	149,964
Other	575	2,865	24	461	3,925
Common and other property					
Common general plant asbestos	480	—	25	—	505
Common miscellaneous	1,458	—	53	23	1,534
Total liability	<u>\$ 1,815,390</u>	<u>\$ 25,252</u>	<u>\$ 95,045</u>	<u>\$ 510,944</u>	<u>\$ 2,446,631</u>

(a) In 2014, revisions were made to various AROs due to revised estimated cash flows and the timing of those cash flows. Changes to estimated nuclear production decommissioning primarily relate to the triennial filing made to the MPUC in December 2014. See additional information in Note 14. Changes in estimated excavation costs and the timing of future retirement activities resulted in revisions to AROs related to gas transmission and distribution.

(b) There were no ARO liabilities settled during the year ended Dec. 31, 2014.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$1.7 billion as of Dec. 31, 2014, consisting of external investment funds.

Indeterminate AROs — PSCo has certain underground natural gas storage facilities that have special closure requirements for which the final removal date cannot be determined. Additionally, outside of the known and recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of Xcel Energy's facilities, but no confirmation or measurement of the amount of asbestos or cost of removal could be determined as of Dec. 31, 2015. Therefore, an ARO has not been recorded for these facilities.

Removal Costs — Xcel Energy records a regulatory liability for the plant removal costs of generation, transmission and distribution facilities of its utility subsidiaries that are recovered currently in rates. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long time periods over which the amounts were accrued and the changing of rates over time, the utility subsidiaries have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates.

The accumulated balances by entity were as follows at Dec. 31:

(Millions of Dollars)	2015	2014
NSP-Minnesota	\$ 430	\$ 396
PSCo.	364	366
SPS	204	68
NSP-Wisconsin.	132	123
Total Xcel Energy	<u>\$ 1,130</u>	<u>\$ 953</u>

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to \$13.5 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured \$375 million of coverage for its public liability exposure with a pool of insurance companies. The remaining \$13.1 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to \$127.3 million per reactor per accident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is \$19.0 million per reactor during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective September 2013.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are \$2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately \$19.9 million for business interruption insurance and \$43.7 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Xcel Energy's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Pacific Northwest FERC Refund Proceeding — A complaint with the FERC posed that sales made in the Pacific Northwest in 2000 and 2001 through bilateral contracts were unjust and unreasonable under the Federal Power Act. The City of Seattle (the City) alleges between \$34 million to \$50 million in sales with PSCo is subject to refund. In 2003, the FERC terminated the proceeding, although it was later remanded back to the FERC in 2007 by the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit).

In May 2015 in the remand proceeding, the FERC issued an order rejecting the City's claim that any of the sales made resulted in an excessive burden and concluded that the City failed to establish a causal link between any contracts and any claimed unlawful market activity. In June 2015, the City requested the FERC grant rehearing of its order, which the FERC denied in December. The City may appeal this order.

Also in December 2015, the Ninth Circuit issued an order and held that the standard of review applied by the FERC to the contracts which the City was challenging is appropriate. The Ninth Circuit dismissed questions concerning whether the FERC properly established the scope of the hearing, and determined that the challenged orders are preliminary and that the Ninth Circuit lacks jurisdiction to review evidentiary decisions until after the FERC's proceedings are final. The City joined the State of California in its request seeking rehearing of this order.

Preliminary calculations of the City of Seattle's claim for refunds from PSCo are approximately \$28 million excluding interest. PSCo has concluded that a loss is reasonably possible with respect to this matter; however, given the surrounding uncertainties, PSCo is currently unable to estimate the amount or range of reasonably possible loss in the event of an adverse outcome of this matter. In making this assessment, PSCo considered two factors. First, notwithstanding PSCo's view that the City of Seattle has failed to apply the standard that the FERC has established in this proceeding, and the recognition that this case raises a novel issue and the scope of the proceeding established by FERC is being challenged in the Ninth Circuit, the outcome of such an appeal cannot be predicted with any certainty. Second, PSCo would expect to make equitable arguments against refunds even if the City of Seattle were to establish that it was overcharged for transactions. If a loss were sustained, PSCo would attempt to recover those losses from other PRPs. No accrual has been recorded for this matter.

Gas Trading Litigation — e prime, inc. (e prime) is a wholly owned subsidiary of Xcel Energy. e prime was in the business of natural gas trading and marketing, but has not engaged in natural gas trading or marketing activities since 2003. Thirteen lawsuits were commenced against e prime and Xcel Energy (and NSP-Wisconsin, in two instances) between 2003 and 2009 alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. The cases were consolidated in U.S. District Court in Nevada. In 2009, five of the cases were settled and one was dismissed. The U.S. District Court in 2011 issued an order dismissing entirely six of the remaining seven lawsuits, and partially dismissing the seventh. Plaintiffs appealed the dismissals to the Ninth Circuit, which reversed the District Court. The matter was ultimately heard by the U.S. Supreme Court in early 2015, which agreed with the Ninth Circuit and remanded the matter to the U.S. District Court. In September 2015, the District Court held a status conference and set deadlines for certain litigation related activities in 2016. A trial date has not yet been set, but is not expected to occur prior to late 2016 or early 2017. Xcel Energy and e prime have concluded that a loss is remote with respect to this matter.

Other Contingencies

Limited Partnership Investment — In October 2015, Energy Impact Fund Investment, LLC (Energy Impact LLC), a wholly-owned non-utility subsidiary of Xcel Energy Inc., entered into a subscription agreement for a limited partnership interest, committing Energy Impact LLC to up to \$50 million of total future investments in the newly formed Energy Impact Fund Limited Partnership (Energy Impact Fund LP) over the next five years. Along with the capital contributions of the other limited partners, who are primarily investor-owned utilities or their affiliates, the funding is expected to be used to make private equity investments in entities that are active developers and producers of new and emerging energy technologies applicable to utility operations, products and services. Energy Impact LLC made \$0.6 million of capital contributions to the limited partnership in 2015 and uses the equity method to account for its investment.

See Note 12 for further discussion.

14. Nuclear Obligations

Fuel Disposal — NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP-Minnesota's nuclear plants as well as from other U.S. nuclear plants, but no such facility is yet available. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. Through May 2014, the fuel disposal fees were based on a charge of 0.1 cent per KWh sold to customers from nuclear generation. Since that time, the DOE has set the fee to zero.

Fuel expense includes the DOE fuel disposal assessments of approximately \$5 million in 2014 and \$10 million in 2013. There were no DOE fuel disposal assessments in 2015. In total, NSP-Minnesota paid approximately \$452.1 million to the DOE through Dec. 31, 2015.

NSP-Minnesota has its own temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities at both sites. The amount of spent fuel storage capacity is determined by the NRC and the MPUC. The Monticello dry-cask storage facility currently stores 15 of the 30 authorized canisters, and the PI dry-cask storage facility currently stores 40 of the 64 authorized casks. Other alternatives for spent fuel storage are being investigated until a DOE facility is available.

Regulatory Plant Decommissioning Recovery — Decommissioning activities related to NSP-Minnesota’s nuclear facilities are planned to begin at the end of each unit’s operating license and be completed by 2091. NSP-Minnesota’s current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit. The MPUC most recently approved NSP-Minnesota’s 2014 nuclear decommissioning study in October 2015. This cost study quantified decommissioning costs in 2014 dollars and utilized escalation rates of 4.36 percent per year for plant removal activities, and 3.36 percent for spent fuel management and site restoration activities over a 60-year decommissioning scenario.

The total obligation for decommissioning is expected to be funded 100 percent by the external decommissioning trust fund when decommissioning commences. NSP-Minnesota’s most recently approved decommissioning study resulted in an annual funding requirement of \$14 million to be recovered in utility customer rates starting in 2016. This cost study assumes the external decommissioning fund will earn an after-tax return between 5.23 percent and 6.30 percent. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota’s regulatory asset for nuclear decommissioning costs.

As of Dec. 31, 2015, NSP-Minnesota has accumulated \$1.7 billion of assets held in external decommissioning trusts. The following table summarizes the funded status of NSP-Minnesota’s decommissioning obligation based on parameters established in the most recently approved decommissioning study. Xcel Energy believes future decommissioning costs, if necessary, will continue to be recovered in customer rates. The amounts presented below were prepared on a regulatory basis, and are not recorded in the financial statements for the ARO.

(Thousands of Dollars)	Regulatory Basis	
	2015	2014
Estimated decommissioning cost obligation from most recently approved study (in 2014 and 2011 dollars, respectively)	\$ 3,012,342	\$ 2,694,079
Effect of escalating costs (to 2015 and 2014 dollars, respectively, at 4.36/3.36 percent and 3.63/2.63 percent, respectively)	126,464	289,907
Estimated decommissioning cost obligation (in current dollars)	3,138,806	2,983,986
Effect of escalating costs to payment date (4.36/3.36 percent and 3.63/2.63 percent, respectively)	8,066,688	5,597,302
Estimated future decommissioning costs (undiscounted)	11,205,494	8,581,288
Effect of discounting obligation (using average risk-free interest rate of 3.01 percent and 2.82 percent for 2015 and 2014, respectively)	(6,891,392)	(5,044,470)
Discounted decommissioning cost obligation	<u>\$ 4,314,102</u>	<u>\$ 3,536,818</u>
Assets held in external decommissioning trust	\$ 1,724,150	\$ 1,703,921
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	2,589,952	1,832,897

Calculations and data used by the regulator in approving company rates are useful in assessing future cash flows. The regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting. The following table provides a reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Thousands of Dollars)	2015	2014
Discounted decommissioning cost obligation - regulated basis	\$ 4,314,102	\$ 3,536,818
Differences in discount rate and market risk premium	(1,275,438)	(1,275,101)
Operating and maintenance costs not included for GAAP	(897,640)	(547,135)
Differences in cost studies (2011 versus 2014, no change in 2015)	—	323,365
Nuclear production decommissioning ARO - GAAP	<u>\$ 2,141,024</u>	<u>\$ 2,037,947</u>

Decommissioning expenses recognized as a result of regulation for the years ending Dec. 31 were:

(Thousands of Dollars)	2015	2014	2013
Annual decommissioning recorded as depreciation expense: ^(a)	\$ 6,862	\$ 7,138	\$ 6,402

^(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

The 2014 nuclear decommissioning filing approved in 2015 has been used for the regulatory presentation.

15. Regulatory Assets and Liabilities

Xcel Energy Inc. and subsidiaries prepare their consolidated financial statements in accordance with the applicable accounting guidance, as discussed in Note 1. Under this guidance, regulatory assets and liabilities are created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of Xcel Energy's business that is not regulated cannot establish regulatory assets and liabilities. If changes in the utility industry or the business of Xcel Energy no longer allow for the application of regulatory accounting guidance under GAAP, Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in net income or OCI.

The components of regulatory assets shown on the consolidated balance sheets at Dec. 31, 2015 and 2014 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2015		Dec. 31, 2014	
			Current	Noncurrent	Current	Noncurrent
Regulatory Assets						
Pension and retiree medical obligations ^(a)	9	Various	\$ 90,249	\$ 1,368,115	\$ 95,054	\$ 1,402,360
Recoverable deferred taxes on AFUDC recorded in plant	1	Plant lives	—	408,994	—	395,329
Net AROs ^(b)	1, 13, 14	Plant lives	—	306,671	—	189,056
Environmental remediation costs	1, 13	Various	6,702	166,883	4,594	149,812
Contract valuation adjustments ^(c)	1, 11	Term of related contract	26,379	128,780	17,730	144,273
Depreciation differences	1	One to sixteen years	14,221	99,835	10,700	104,743
Purchased power contract costs	13	Term of related contract	1,587	70,411	858	69,908
PI EPU	12	Nineteen years	2,967	65,060	8,743	67,379
Conservation programs ^(d)	1	One to five years	31,793	50,047	61,866	58,174
Nuclear refueling outage costs	1	One to two years	67,545	28,913	62,499	19,745
State commission adjustments	1	Plant lives	988	26,708	571	26,092
Losses on reacquired debt	4	Term of related debt	5,008	26,268	5,258	31,276
Renewable resources and environmental initiatives	13	One to two years	33,014	23,565	24,891	29,902
Property tax		One to six years	21,757	14,428	28,024	31,429
Gas pipeline inspection and remediation costs	12	One to four years	6,858	13,662	9,981	21,869
Recoverable purchased natural gas and electric energy costs	1	One to two years	11,783	12,762	68,841	4,745
Other		Various	23,779	47,639	44,448	28,124
Total regulatory assets			<u>\$ 344,630</u>	<u>\$ 2,858,741</u>	<u>\$ 444,058</u>	<u>\$ 2,774,216</u>

^(a) Includes \$257.5 million and \$282.4 million for the regulatory recognition of the NSP-Minnesota pension expense of which \$21.3 million and \$23.8 million is included in the current asset at Dec. 31, 2015 and 2014, respectively. Also included are \$12.5 million and \$26.1 million of regulatory assets related to the nonqualified pension plan of which \$4.0 million and \$2.5 million is included in the current asset at Dec. 31, 2015 and 2014, respectively.

^(b) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.

^(c) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

^(d) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

The components of regulatory liabilities shown on the consolidated balance sheets at Dec. 31, 2015 and 2014 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2015		Dec. 31, 2014	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Plant removal costs	1, 13	Plant lives	\$ —	\$ 1,131,023	\$ —	\$ 953,660
Investment tax credit deferrals	1, 6	Various	—	48,985	—	52,666
Deferred income tax adjustment	1, 6	Various	—	46,737	—	48,622
Renewable resources and environmental initiatives	12, 13	Various	6,271	41,869	10,427	10,376
PSCo earnings test	12	One to two years	42,868	9,472	57,127	42,819
Gas pipeline inspection costs		Various	1,140	4,273	13,970	642
Gain from asset sales	12	Various	2,640	2,584	2,893	4,472
Deferred electric and steam production and natural gas costs	1	Less than one year	146,235	—	88,527	—
Conservation programs ^(a)	1, 12	Less than one year	34,444	—	103,351	—
Contract valuation adjustments ^(b)	1, 11	Term of related contract	21,661	—	55,751	2,521
DOE settlement	12	One to two years	16,139	—	49,492	—
Low income discount program		Less than one year	2,475	—	3,355	—
Excess depreciation reserve		Less than one year	60	—	10,999	—
Other		Various	32,897	47,946	14,837	47,651
Total regulatory liabilities ^(c)			\$ 306,830	\$ 1,332,889	\$ 410,729	\$ 1,163,429

(a) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(c) Revenue subject to refund of \$75.0 million and \$128.3 million for 2015 and 2014, respectively, is included in other current liabilities.

At Dec. 31, 2015 and 2014, approximately \$169 million and \$323 million of Xcel Energy's regulatory assets represented past expenditures not currently earning a return, respectively. This amount primarily includes recoverable purchased natural gas and electric energy costs and certain expenditures associated with renewable resources and environmental initiatives.

16. Other Comprehensive Income

Changes in accumulated other comprehensive (loss) income, net of tax, for the years ended Dec. 31, 2015 and 2014 were as follows:

(Thousands of Dollars)	Year Ended Dec. 31, 2015			
	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	\$ (57,628)	\$ 110	\$ (50,621)	\$ (108,139)
Other comprehensive loss before reclassifications	(70)	—	(7,906)	(7,976)
Losses reclassified from net accumulated other comprehensive loss	2,836	—	3,526	6,362
Net current period other comprehensive income (loss)	2,766	—	(4,380)	(1,614)
Accumulated other comprehensive (loss) income at Dec. 31	<u>\$ (54,862)</u>	<u>\$ 110</u>	<u>\$ (55,001)</u>	<u>\$ (109,753)</u>

(Thousands of Dollars)	Year Ended Dec. 31, 2014			
	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	\$ (59,753)	\$ 77	\$ (46,599)	\$ (106,275)
Other comprehensive (loss) income before reclassifications	(163)	33	(7,517)	(7,647)
Losses reclassified from net accumulated other comprehensive loss	2,288	—	3,495	5,783
Net current period other comprehensive income (loss)	2,125	33	(4,022)	(1,864)
Accumulated other comprehensive (loss) income at Dec. 31	<u>\$ (57,628)</u>	<u>\$ 110</u>	<u>\$ (50,621)</u>	<u>\$ (108,139)</u>

Reclassifications from accumulated other comprehensive loss for the years ended Dec. 31, 2015 and 2014 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss	
	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014
(Gains) losses on cash flow hedges:		
Interest rate derivatives	\$ 4,515 ^(a)	\$ 3,836 ^(a)
Vehicle fuel derivatives	131 ^(b)	(55) ^(b)
Total, pre-tax	4,646	3,781
Tax benefit	(1,810)	(1,493)
Total, net of tax	2,836	2,288
Defined benefit pension and postretirement (gains) losses:		
Amortization of net loss	6,132 ^(c)	5,998 ^(c)
Prior service (credit) cost	(357) ^(c)	(344) ^(c)
Total, pre-tax	5,775	5,654
Tax benefit	(2,249)	(2,159)
Total, net of tax	3,526	3,495
Total amounts reclassified, net of tax	<u>\$ 6,362</u>	<u>\$ 5,783</u>

(a) Included in interest charges.

(b) Included in O&M expenses.

(c) Included in the computation of net periodic pension and postretirement benefit costs. See Note 9 for details regarding these benefit plans.

17. Segments and Related Information

The regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- Xcel Energy's regulated electric utility segment generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes wholesale commodity and trading operations.
- Xcel Energy's regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services, nonutility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of \$130.0 million and \$83.1 million as of Dec. 31, 2015 and 2014, respectively, included in the regulated natural gas utility segment.

Asset and capital expenditure information is not provided for Xcel Energy's reportable segments because as an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

To report income from operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

The accounting policies of the segments are the same as those described in Note 1.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2015					
Operating revenues from external customers	\$ 9,275,986	\$ 1,672,081	\$ 76,419	\$ —	\$ 11,024,486
Intersegment revenues	1,511	1,251	—	(2,762)	—
Total revenues	<u>\$ 9,277,497</u>	<u>\$ 1,673,332</u>	<u>\$ 76,419</u>	<u>\$ (2,762)</u>	<u>\$ 11,024,486</u>
Depreciation and amortization	\$ 962,565	\$ 154,892	\$ 7,067	\$ —	\$ 1,124,524
Interest charges and financing costs	425,999	49,763	93,272	—	569,034
Income tax expense (benefit)	508,568	60,545	(26,394)	—	542,719
Net income	921,403	106,023	(42,941)	—	984,485
(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2014					
Operating revenues from external customers	\$ 9,465,890	\$ 2,142,738	\$ 77,507	\$ —	\$ 11,686,135
Intersegment revenues	1,774	5,893	—	(7,667)	—
Total revenues	<u>\$ 9,467,664</u>	<u>\$ 2,148,631</u>	<u>\$ 77,507</u>	<u>\$ (7,667)</u>	<u>\$ 11,686,135</u>
Depreciation and amortization	\$ 866,746	\$ 144,661	\$ 7,638	\$ —	\$ 1,019,045
Interest charges and financing costs	397,824	43,940	86,442	—	528,206
Income tax expense (benefit)	512,551	76,418	(65,154)	—	523,815
Net income (loss)	890,535	128,559	2,212	—	1,021,306
(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2013					
Operating revenues from external customers	\$ 9,034,045	\$ 1,804,679	\$ 76,198	\$ —	\$ 10,914,922
Intersegment revenues	1,332	2,717	—	(4,049)	—
Total revenues	<u>\$ 9,035,377</u>	<u>\$ 1,807,396</u>	<u>\$ 76,198</u>	<u>\$ (4,049)</u>	<u>\$ 10,914,922</u>
Depreciation and amortization	\$ 840,833	\$ 128,186	\$ 8,844	\$ —	\$ 977,863
Interest charges and financing costs	386,198	44,927	104,895	—	536,020
Income tax expense (benefit)	495,044	25,543	(36,611)	—	483,976
Net income (loss)	850,572	123,702	(26,040)	—	948,234

18. Summarized Quarterly Financial Data (Unaudited)

(Amounts in thousands, except per share data)	Quarter Ended			
	March 31, 2015	June 30, 2015	Sept. 30, 2015	Dec. 31, 2015
Operating revenues	\$ 2,962,219	\$ 2,515,134	\$ 2,901,312	\$ 2,645,821
Operating income	350,845	422,845	785,812	441,010
Net income	152,066	196,931	426,463	209,025
EPS total — basic	\$ 0.30	\$ 0.39	\$ 0.84	\$ 0.41
EPS total — diluted	0.30	0.39	0.84	0.41
Cash dividends declared per common share	0.32	0.32	0.32	0.32
(Amounts in thousands, except per share data)	Quarter Ended			
	March 31, 2014	June 30, 2014	Sept. 30, 2014	Dec. 31, 2014
Operating revenues	\$ 3,202,604	\$ 2,685,096	\$ 2,869,807	\$ 2,928,628
Operating income	493,992	397,208	665,680	391,250
Net income	261,221	195,164	368,582	196,339
EPS total — basic	\$ 0.52	\$ 0.39	\$ 0.73	\$ 0.39
EPS total — diluted	0.52	0.39	0.73	0.39
Cash dividends declared per common share	0.30	0.30	0.30	0.30

Item 9 — Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A — Controls and Procedures

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Dec. 31, 2015, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No change in Xcel Energy's internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Xcel Energy's internal control over financial reporting. Xcel Energy maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting.

Xcel Energy has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level. During the year and in preparation for issuing its report for the year ended Dec. 31, 2015 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board and as approved by the SEC and as indicated in Management Report on Internal Controls herein.

Effective January 2016, Xcel Energy implemented the general ledger modules of a new enterprise resource planning ("ERP") system to improve certain financial and related transaction processes. During 2016 and 2017, Xcel Energy will continue implementing additional modules and expects to begin conversion of existing work management system to this same ERP system. In connection with this ongoing implementation, Xcel Energy is updating its internal control over financial reporting, as necessary, to accommodate modifications to its business processes and accounting procedures. Xcel Energy does not believe that this implementation will have an adverse effect on its internal control over financial reporting.

Item 9B — Other Information

None.

PART III

Item 10 — Directors, Executive Officers and Corporate Governance

Information required under this Item with respect to Directors and Corporate Governance is set forth in Xcel Energy Inc.'s Proxy Statement for its 2016 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

Item 11 — Executive Compensation

Information required under this Item is set forth in Xcel Energy Inc.'s Proxy Statement for its 2016 Annual Meeting of Shareholders, which is incorporated by reference.

Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2016 Annual Meeting of Shareholders, which is incorporated by reference.

Item 13 — Certain Relationships and Related Transactions, and Director Independence

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2016 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 — Principal Accountant Fees and Services

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2016 Annual Meeting of Shareholders, which is incorporated by reference.

PART IV

Item 15 — Exhibits, Financial Statement Schedules

1. Consolidated Financial Statements:
Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2015.
Report of Independent Registered Public Accounting Firm — Financial Statements
Report of Independent Registered Public Accounting Firm — Internal Controls Over Financial Reporting
Consolidated Statements of Income — For the three years ended Dec. 31, 2015, 2014 and 2013.
Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2015, 2014 and 2013.
Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2015, 2014 and 2013.
Consolidated Balance Sheets — As of Dec. 31, 2015 and 2014.
Consolidated Statements of Common Stockholders' Equity — For the three years ended Dec. 31, 2015, 2014 and 2013.
Consolidated Statements of Capitalization — As of Dec. 31, 2015 and 2014.
 2. Schedule I — Condensed Financial Information of Registrant.
Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2015, 2014 and 2013.
 3. Exhibits
- * Indicates incorporation by reference
- + Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors
- ^t Certain portions of this agreement have been omitted pursuant to a request for confidential treatment and have been filed separately with the SEC.

Xcel Energy Inc.

- 1.01* Equity Distribution Agreement, dated March 5, 2013, between Xcel Energy Inc. and Barclays Capital Inc. (Exhibit 1.1 to Form 8-K dated March 5, 2013 (file no. 001-03034)).
- 1.02* Equity Distribution Agreement, dated March 5, 2013, between Xcel Energy Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated (Exhibit 1.2 to Form 8-K dated March 5, 2013 (file no. 001-03034)).
- 1.03* Equity Distribution Agreement, dated March 5, 2013, between Xcel Energy Inc. and Morgan Stanley & Co. LLC (Exhibit 1.3 to Form 8-K dated March 5, 2013 (file no. 001-03034)).

PSCo

- 2.01*^t Purchase and Sale Agreement by and between Riverside Energy Center, LLC and Calpine Development Holdings, Inc., as Sellers, and PSCo, as Purchaser, dated as of April 2, 2010 (excluding certain schedules and exhibits referred to in the agreement, as amended, which the Registrant agrees to furnish supplemental to the SEC upon request) (Exhibit 2.01 to Form 10-Q for the quarter ended June 30, 2010 (file no. 001-03034)).

Xcel Energy Inc.

- 3.01* Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 17, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
- 3.02* Xcel Energy Inc. Bylaws, as amended on Feb. 17, 2016 (Exhibit 3.01 to Form 8-K dated Feb. 17, 2016 (file no. 001-03034)).

Xcel Energy Inc.

- 4.01* Indenture dated Dec. 1, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee. (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Dec. 14, 2000).
- 4.02* Supplemental Indenture No. 3 dated June 1, 2006 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating \$300 million principal amount of 6.5 percent Senior Notes, Series due 2036 (Exhibit 4.01 to Current Report on Form 8-K (file no. 001-03034) dated June 6, 2006).
- 4.03* Supplemental Indenture No. 4 dated March 30, 2007 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating \$253.979 million aggregate principal amount of 5.613 percent Senior Notes, Series due 2017 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 30, 2007).
- 4.04* Junior Subordinated Indenture, dated as of Jan. 1, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
- 4.05* Supplemental Indenture No. 1, dated Jan. 16, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating \$400 million principal amount of 7.6 percent Junior Subordinated Notes, Series due 2068 (Exhibit 4.02 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
- 4.06* Replacement Capital Covenant, dated Jan. 16, 2008 (Exhibit 4.03 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
- 4.07* Supplemental Indenture No. 5 dated as of May 1, 2010 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating \$550 million principal amount of 4.70 percent Senior Notes, Series due May 15, 2020 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated May 10, 2010).
- 4.08* Supplemental Indenture No. 6 dated as of Sept. 1, 2011 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating \$250 million principal amount of 4.80 percent Senior Notes, Series due Sept. 15, 2041 (Exhibit 4.01 to Form 8-K dated Sept. 12, 2011 (file no. 001-03034)).
- 4.09* Supplemental Indenture No. 7 dated as of May 1, 2013 between Xcel Energy and Wells Fargo Bank, NA, as Trustee, creating \$450 million principal amount of 0.75 percent Senior Notes, Series due May 9, 2016 (Exhibit 4.01 to Form 8-K dated May 9, 2013 (file no. 001-03034)).
- 4.10* Supplemental Indenture No. 8 dated as of June 1, 2015 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating \$250,000,000 aggregate principal amount of 1.20 percent Senior Notes, Series due June 1, 2017 and \$250,000,000 aggregate principal amount of 3.30 percent Senior Notes, Series due June 1, 2025. (Exhibit 4.01 to Form 8-K dated June 1, 2015 (file no. 001-03034)).

NSP-Minnesota

- 4.11* Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds (Exhibit 4.02 to Form 10-K of NSP-Minnesota for the year ended Dec. 31, 1988 (file no. 001-03034)). Supplemental Indentures between NSP-Minnesota and said Trustee, dated as follows:
 - Supplemental Trust Indenture dated June 1, 1995, creating \$250 million principal amount of 7.125 percent First Mortgage Bonds, Series due July 1, 2025 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated June 28, 1995).
 - Supplemental Trust Indenture dated April 1, 1997, creating \$100 million principal amount of 8.5 percent First Mortgage Bonds, Series due Sept. 1, 2019 and \$27.9 million principal amount of 8.5 percent First Mortgage Bonds, Series due March 1, 2019 (Exhibit 4.47 to Form 10-K (file no. 001-03034) dated Dec. 31, 1997).
 - Supplemental Trust Indenture dated March 1, 1998, creating \$150 million principal amount of 6.5 percent First Mortgage Bonds, Series due March 1, 2028 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 11, 1998).
- 4.12* Supplemental Trust Indenture dated Aug. 1, 2000 (Assignment and Assumption of Trust Indenture) (Exhibit 4.51 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
- 4.13* Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities. (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-03034) dated July 21, 1999).
- 4.14* Supplemental Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee (Assignment and Assumption of Indenture) (Exhibit 4.63 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
- 4.15* Supplemental Trust Indenture dated July 1, 2002 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating \$69 million principal amount of 8.5 percent First Mortgage Bonds, Series due April 1, 2030 (Exhibit 4.06 to NSP-Minnesota Quarterly Report on Form 10-Q (file no. 001-31387) dated Sept. 30, 2002).

- 4.16* Supplemental Trust Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating \$250 million principal amount of 5.25 percent First Mortgage Bonds, Series due July 15, 2035 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K (file no. 001-31387) dated July 14, 2005).
- 4.17* Supplemental Trust Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating \$400 million principal amount of 6.25 percent First Mortgage Bonds, Series due June 1, 2036 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K (file no. 001-31387) dated May 18, 2006).
- 4.18* Supplemental Trust Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated June 19, 2007).
- 4.19* Supplemental Trust Indenture dated March 1, 2008 between NSP-Minnesota and The Bank of New York Trust Company, NA, as successor Trustee (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated March 11, 2008).
- 4.20* Supplemental Trust Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and The Bank of New York Mellon Trust Co., NA, as successor Trustee, creating \$300 million principal amount of 5.35 percent First Mortgage Bonds, Series due Nov. 1, 2039 (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated Nov. 16, 2009).
- 4.21* Supplemental Trust Indenture dated as of Aug. 1, 2010 between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating \$250 million principal amount of 1.950 percent First Mortgage Bonds, Series due Aug. 15, 2015 and \$250 million principal amount of 4.850 percent First Mortgage Bonds, Series due Aug. 15, 2040 (Exhibit 4.01 to NSP-Minnesota Form 8-K dated Aug. 4, 2010 (file no. 001-31387)).
- 4.22* Supplemental Trust Indenture dated as of Aug. 1, 2012 between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating \$300 million principal amount of 2.15 percent First Mortgage Bonds, Series due Aug. 15, 2022 and \$500 million principal amount of 3.40 percent First Mortgage Bonds, Series due Aug. 15, 2042 (Exhibit 4.01 to NSP-Minnesota Form 8-K dated Aug. 13, 2012 (file no. 001-31387)).
- 4.23* Supplemental Trust Indenture dated as of May 1, 2013 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating \$400 million principal amount of 2.60 percent First Mortgage Bonds, Series due May 15, 2023 (Exhibit 4.01 to NSP-Minnesota Form 8-K dated May 20, 2013 (file no. 001-31387)).
- 4.24* Supplemental Trust Indenture dated as of May 1, 2014 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating \$300 million principal amount of 4.125 percent First Mortgage Bonds, Series due May 15, 2044. (Exhibit 4.01 to NSP-Minnesota Form 8-K dated May 13, 2014 (file no. 001-31387)).
- 4.25* Supplemental Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating \$300,000,000 principal amount of 2.20 percent First Mortgage Bonds, Series due Aug. 15, 2020 and \$300,000,000 principal amount of 4.00 percent First Mortgage Bonds, Series due Aug. 15, 2045 (Exhibit 4.01 to Form 8-K of NSP-Minnesota dated Aug. 11, 2015 (file no. 001-31387)).

NSP-Wisconsin

- 4.26* Supplemental and Restated Trust Indenture, dated March 1, 1991, between NSP-Wisconsin and First Wisconsin Trust company, providing for the issuance of First Mortgage Bonds (Exhibit 4.01 to Registration Statement 33-39831).
- 4.27* Supplemental Trust Indenture, dated April 1, 1991 (Exhibit 4.01 to Form 10-Q (file no. 001-03140) for the quarter ended March 31, 1991).
- 4.28* Supplemental Trust Indenture, dated Dec. 1, 1996, between NSP-Wisconsin and Firststar Trust Company, as Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Dec. 12, 1996).
- 4.29* Trust Indenture dated Sept. 1, 2000, between NSP-Wisconsin and Firststar Bank, NA as Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Sept. 25, 2000).
- 4.30* Supplemental Trust Indenture dated Sept. 1, 2003 between NSP-Wisconsin and U.S. Bank National Association, supplementing indentures dated April 1, 1947 and March 1, 1991 (Exhibit 4.05 to Xcel Energy Form 10-Q (file no. 001-03034) for the quarter ended Sept. 30, 2003).
- 4.31* Supplemental Trust Indenture dated as of Sept. 1, 2008 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating \$200 million principal amount of 6.375 percent First Mortgage Bonds, Series due Sept. 1, 2038 (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated Sept. 3, 2008 (file no. 001-03140)).
- 4.32* Supplemental Trust Indenture dated as of Oct. 1, 2012 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating \$100 million principal amount of 3.700 percent First Mortgage Bonds, Series due Oct. 1, 2042 (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated Oct. 10, 2012 (file no. 001-03140)).
- 4.33* Supplemental Trust Indenture dated as of June 1, 2014 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating \$100 million principal amount of 3.30 percent First Mortgage Bonds, Series due June 15, 2024. (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated June 23, 2014 (file no. 001-03140)).

PSCo

- 4.34* Indenture, dated as of Oct. 1, 1993, between PSCo and Morgan Guaranty Trust Company of New York, as trustee, providing for the issuance of First Collateral Trust Bonds (Form 10-Q, Sept. 30, 1993 — Exhibit 4(a)).
- 4.35* Indentures supplemental to Indenture dated as of Oct. 1, 1993, between PSCo and Morgan Guaranty Trust Company of New York, as trustee:

	Dated as of	Previous Filing: Form; Date or file no.	Exhibit No.
	Nov. 1, 1993	S-3, (33-51167)	4(b)(2)
	Jan. 1, 1994	10-K, 1993	4(b)(3)
	Sept. 2, 1994	8-K, September 1994	4(b)
	Nov. 1, 1996	10-K, 1996 (001-03280)	4(b)(3)
	Feb. 1, 1997	10-Q, March 31, 1997 (001-03280)	4(a)
	April 1, 1998	10-Q, March 31, 1998 (001-03280)	4(b)
	Aug. 15, 2002	10-Q, Sept. 30, 2002 (001-03280)	4.03
	Aug. 1, 2005	8-K, Aug. 18, 2005 (001-03280)	4.02
4.36*	Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities and First Supplemental Indenture dated July 15, 1999, between PSCo and The Bank of New York (Exhibits 4.1 and 4.2 to Form 8-K (file no. 001-03280) dated July 13, 1999).		
4.37*	Financing Agreement between Adams County, Colorado and PSCo, dated as of Aug. 1, 2005 relating to \$129.5 million Adams County, Colorado Pollution Control Refunding Revenue Bonds, 2005 Series A (Exhibit 4.01 to PSCo Current Report on Form 8-K, dated Aug. 18, 2005, file no. 001-03280).		
4.38*	Supplemental Indenture, dated Aug. 1, 2007, between PSCo and U.S. Bank Trust National Association, as successor Trustee (Exhibit 4.01 to PSCo Form 8-K (file no. 001-03280) dated Aug. 8, 2007).		
4.39*	Supplemental Indenture dated as of Aug. 1, 2008, between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating \$300 million principal amount of 5.80 percent First Mortgage Bonds, Series No. 18 due 2018 and \$300 million principal amount of 6.50 percent First Mortgage Bonds, Series No. 19 due 2038 (Exhibit 4.01 of Form 8-K of PSCo dated Aug. 6, 2008 (file no. 001-03280)).		
4.40*	Supplemental Indenture dated as of May 1, 2009 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating \$400 million principal amount of 5.125 percent First Mortgage Bonds, Series No. 20 due 2019 (Exhibit 4.01 of Form 8-K of PSCo dated May 28, 2009 (file no. 001-03280)).		
4.41*	Supplemental Indenture dated as of Nov. 1, 2010 between PSCo and U.S. Bank National Association, as successor Trustee, creating \$400 million principal amount of 3.200 percent First Mortgage Bonds, Series No. 21 due 2020 (Exhibit 4.01 of Form 8-K of PSCo dated Nov. 8, 2010 (file no. 001-03280)).		
4.42*	Supplemental Indenture dated as of Aug. 1, 2011 between PSCo and U.S. Bank National Association, as successor Trustee, creating \$250 million principal amount of 4.75 percent First Mortgage Bonds, Series No. 22 due 2041 (Exhibit 4.01 to Form 8-K of PSCo dated Aug. 9, 2011 (file no. 001-03280)).		
4.43*	Supplemental Indenture dated as of Sept. 1, 2012 between PSCo and U.S. Bank National Association, as successor Trustee, creating \$300 million principal amount of 2.25 percent First Mortgage Bonds, Series No. 23 due 2022 and \$500 million principal amount of 3.60 percent First Mortgage Bonds, Series No. 24 due 2042 (Exhibit 4.01 to PSCo's Form 8-K dated Sept. 11, 2012 (file no. 001-03280)).		
4.44*	Supplemental Indenture dated as of March 1, 2013 between PSCo and U.S. Bank National Association, as successor Trustee, creating \$250 million principal amount of 2.50 percent First Mortgage Bonds, Series No. 25 due 2023 and \$250 million principal amount of 3.95 percent First Mortgage Bonds, Series No. 26 due 2043 (Exhibit 4.01 to Form 8-K of PSCo dated March 26, 2013 (file no. 001-03280)).		
4.45*	Supplemental Indenture dated as of March 1, 2014 between PSCo and U.S. Bank National Association, as successor Trustee, creating \$300 million principal amount of 4.30 percent First Mortgage Bonds, Series No. 27 due 2044. (Exhibit 4.01 to Form 8-K of PSCo dated March 10, 2014 (file no. 001-03280)).		
4.46*	Supplemental Indenture dated as of May 1, 2015 between PSCo and U.S. Bank National Association, as successor Trustee, creating \$250,000,000 principal amount of 2.90 percent First Mortgage Bonds, Series No. 28 due 2025. (Exhibit 4.01 to Form 8-K of PSCo dated May 12, 2015 (file no. 001-03280)).		
SPS			
4.47*	Indenture dated Feb. 1, 1999 between SPS and The Chase Manhattan Bank (Exhibit 99.2 to Form 8-K (file no. 001-03789) dated Feb. 25, 1999).		
4.48*	Third Supplemental Indenture dated Oct. 1, 2003 to the indenture dated Feb. 1, 1999 between SPS and JPMorgan Chase Bank, as successor Trustee, creating \$100 million principal amount of Series C and Series D Notes, 6 percent due 2033 (Exhibit 4.04 to Xcel Energy Form 10-Q (file no. 001-03034) for the quarter ended Sept. 30, 2003).		
4.49*	Fourth Supplemental Indenture dated Oct. 1, 2006 between SPS and The Bank of New York, as successor Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03789) dated Oct. 3, 2006).		
4.50*	Red River Authority for Texas Indenture of Trust dated July 1, 1991 (Form 10-K, Aug. 31, 1991 — Exhibit 4(b)).		
4.51*	Fifth Supplemental Indenture dated as of Nov. 1, 2008 between SPS and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating \$250 million principal amount of Series G Senior Notes, 8.75 percent due 2018 (Exhibit 4.01 of Form 8-K of SPS, dated Nov. 14, 2008 (file no. 001- 03789))		

- 4.52* Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank National Association, as Trustee (Exhibit 4.01 to Form 8-K dated Aug. 10, 2011 (file no. 001-03789)).
- 4.53* Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank National Association, as Trustee, creating \$200 million principal amount of 4.50 percent First Mortgage Bonds, Series No. 1 due 2041 (Exhibit 4.02 to Form 8-K dated Aug. 10, 2011 (file no. 001-03789)).
- 4.54* Sixth Supplemental Indenture dated as of June 1, 2014 between SPS and The Bank of New York Mellon Trust Company, N.A., as successor Trustee. (Exhibit 4.03 to SPS' Form 8-K dated June 2, 2014 (file no. 001-03789)).
- 4.55* Supplemental Indenture No. 2 dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee. (Exhibit 4.06 to SPS' Form 8-K dated June 2, 2014 (file no. 001-03789)).
- 4.56* Supplemental Indenture No. 3 dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee, creating \$150 million principal amount of 3.30 percent First Mortgage Bonds, Series No. 3 due 2024. (Exhibit 4.02 to SPS' Form 8-K dated June 9, 2014 (file no. 001-03789)).

Xcel Energy Inc.

- 10.01** Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement) (Exhibit 10.02 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
- 10.02** Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Amendment and Restatement) (Exhibit 10.05 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
- 10.03** Xcel Energy Inc. Non-Employee Directors Deferred Compensation Plan as amended and restated Jan. 1, 2009 (Exhibit 10.08 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
- 10.04* Form of Services Agreement between Xcel Energy Services Inc. and utility companies (Exhibit H-1 to Form U5B (file no. 001-03034) dated Nov. 16, 2000).
- 10.05** Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009 (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
- 10.06** Amendment dated Aug. 26, 2009 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.06 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
- 10.07** Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement (Exhibit 10.08 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
- 10.08** Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix A to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2010).
- 10.09** Xcel Energy Inc. 2010 Executive Annual Discretionary Award Plan (Exhibit 10.24 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2009).
- 10.10** Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2010).
- 10.11** Xcel Energy Inc. 2010 Executive Annual Discretionary Award Plan (as amended and restated effective Dec. 15, 2010) (Exhibit 10.23 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
- 10.12** Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Bonus Stock Agreement (Exhibit 10.24 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
- 10.13** Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Performance Share Agreement (Exhibit 10.25 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
- 10.14a** Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Restricted Stock Unit Agreement (Exhibit 10.26 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
- 10.14b** Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Time-Based Restricted Stock Unit Agreement (Exhibit 10.14b to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2012).
- 10.15** Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011 (Appendix A to the Xcel Energy Definitive Proxy Statement (file no. 001-03034) filed April 5, 2011).
- 10.16** Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.07 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
- 10.17** First Amendment effective Nov. 29, 2011 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2011).
- 10.18** Second Amendment dated Oct. 26, 2011 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.18 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2011).
- 10.19** First Amendment dated Feb. 20, 2013 to the Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (Exhibit 10.01 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 2013).
- 10.20** Fourth Amendment dated Feb. 20, 2013 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.02 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 2013).

- 10.21** First Amendment dated May 21, 2013 to the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) (Exhibit 10.21 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
- 10.22** Second Amendment dated May 21, 2013 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.22 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
- 10.23** Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Long-Term Incentive Award Agreement (Exhibit 10.23 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
- 10.24** Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.01 to Form 8-K of Xcel Energy, dated Oct. 14, 2014 (file no. 001-03034)).
- 10.25** Xcel Energy Inc. 2015 Omnibus Incentive Plan (incorporated by reference to Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2015).
- 10.26** Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. (As First Effective May 20, 2015) under the Xcel Energy Inc. 2015 Omnibus Incentive Plan. (Exhibit 10.02 to Form 8-K of Xcel Energy, dated May 26, 2015 (file no. 001-03034)).
- 10.27** Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions (Restricted Stock Units and Performance Share Units) under the Xcel Energy Inc. 2015 Omnibus Incentive Plan. (Exhibit 10.03 to Form 8-K of Xcel Energy, dated May 26, 2015 (file no. 001-03034)).
- 10.28+ Xcel Energy Inc. 2015 Omnibus Incentive Plan Form of Award Agreement.
- 10.29+ Xcel Energy Inc. Executive Annual Incentive Award Sub-plan pursuant to the Xcel Energy Inc. 2015 Omnibus Incentive Plan.

NSP-Minnesota

- 10.30* Ownership and Operating Agreement, dated March 11, 1982, between NSP-Minnesota, Southern Minnesota Municipal Power Agency and United Minnesota Municipal Power Agency concerning Sherburne County Generating Unit No. 3 (Exhibit 10.01 to Form 10-Q for the quarter ended Sept. 30, 1994 (file no. 001-03034)).
- 10.31* Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota (Exhibit 10.01 to NSP-Wisconsin Form S-4 (file no. 333-112033) dated Jan. 21, 2004).
- 10.32* Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.02 to Form 8-K of Xcel Energy, dated Oct. 14, 2014 (file no. 001-03034)).

NSP-Wisconsin

- 10.33* Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota (Exhibit 10.01 to Form S-4 (file no. 333-112033) dated Jan. 21, 2004).
- 10.34* Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.05 to Form 8-K of Xcel Energy, dated Oct. 14, 2014 (file no. 001-03034)).

PSCo

- 10.35* Amended and Restated Coal Supply Agreement entered into Oct. 1, 1984 but made effective as of Jan. 1, 1976 between PSCo and Amax Inc. on behalf of its division, Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1984 — Exhibit 10(c)(1)).
- 10.36* First Amendment to Amended and Restated Coal Supply Agreement entered into May 27, 1988 but made effective Jan. 1, 1988 between PSCo and Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1988 — Exhibit 10(c)(2)).
- 10.37* Proposed Settlement Agreement excerpts, as filed with the CPUC (Exhibit 99.02 to Form 8-K of Xcel Energy (file no. 001-03034) dated Dec. 3, 2004).
- 10.38* Settlement Agreement among PSCo and Concerned Environmental and Community Parties, dated Dec. 3, 2004 (Exhibit 99.03 to Form 8-K of Xcel Energy (file no. 001-03034) dated Dec. 3, 2004).
- 10.39* Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.03 to Form 8-K of Xcel Energy, dated Oct. 14, 2014 (file no. 001-03034)).

SPS

- 10.40* Coal Supply Agreement (Harrington Station) between SPS and TUCO, dated May 1, 1979 (Form 8-K (file no. 001-03789), May 14, 1979 — Exhibit 3).
- 10.41* Master Coal Service Agreement between Swindell-Dressler Energy Supply Co. and TUCO, dated July 1, 1978 (Form 8-K (file no. 001-03789), May 14, 1979 — Exhibit 5(A)).
- 10.42* Guaranty of Master Coal Service Agreement between Swindell-Dressler Energy Supply Co. and TUCO (Form 8-K (file no. 001-03789) May 14, 1979 — Exhibit 5(B)).
- 10.43* Coal Supply Agreement (Tolk Station) between SPS and TUCO dated April 30, 1979, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q for the quarter ended Feb. 28, 1982 (file no. 001-03789) — Exhibit 10(b)).
- 10.44* Master Coal Service Agreement between Wheelabrator Coal Services Co. and TUCO dated Dec. 30, 1981, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q for the quarter ended Feb. 28, 1982 (file no. 001-03789) — Exhibit 10(c)).
- 10.45* Power Purchase Agreement dated May 23, 1997 between Borger Energy Associates, L.P. and SPS.
- 10.46* Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.04 to Form 8-K of Xcel Energy, dated Oct. 14, 2014 (file no. 001-03034)).

Xcel Energy Inc.

- 12.01 Statement of Computation of Ratio of Earnings to Fixed Charges.
- 21.01 Subsidiaries of Xcel Energy Inc.
- 23.01 Consent of Independent Registered Public Accounting Firm.
- 24.01 Powers of Attorney.
- 31.01 Principal Executive Officer's certification pursuant to 18 U.S. C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 31.02 Principal Financial Officer's certification pursuant to 18 U.S. C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 32.01 Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- 99.01 Statement pursuant to Private Securities Litigation Reform Act of 1995.
- 101 The following materials from Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2015 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity, (vi) Consolidated Statements of Capitalization, (vii) Notes to Consolidated Financial Statements, (viii) document and entity information, (ix) Schedule I, and (x) Schedule II.

XCEL ENERGY INC.
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(amounts in thousands, except per share data)

	Year Ended Dec. 31		
	2015	2014	2013
Income			
Equity earnings of subsidiaries	\$ 1,045,788	\$ 1,077,714	\$ 1,018,783
Total income	1,045,788	1,077,714	1,018,783
Expenses and other deductions			
Operating expenses	19,865	19,756	18,513
Other income	(1,242)	(537)	(206)
Interest charges and financing costs	91,801	84,830	102,914
Total expenses and other deductions	110,424	104,049	121,221
Income before income taxes	935,364	973,665	897,562
Income tax benefit	(49,121)	(47,641)	(50,672)
Net income	<u>\$ 984,485</u>	<u>\$ 1,021,306</u>	<u>\$ 948,234</u>
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of \$(2,777), \$(2,528) and \$5,897, respectively	\$ (4,380)	\$ (4,022)	\$ 4,714
Derivative instruments, net of tax of \$1,764, \$1,390 and \$2,558, respectively	2,766	2,125	1,488
Other, net of tax of \$0, \$21 and \$117, respectively	—	33	176
Other comprehensive (loss) income	(1,614)	(1,864)	6,378
Comprehensive income	<u>\$ 982,871</u>	<u>\$ 1,019,442</u>	<u>\$ 954,612</u>
Weighted average common shares outstanding:			
Basic	507,768	503,847	496,073
Diluted	508,168	504,117	496,532
Earnings per average common share:			
Basic	\$ 1.94	\$ 2.03	\$ 1.91
Diluted	1.94	2.03	1.91
Cash dividends declared per common share	1.28	1.20	1.11

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED STATEMENTS OF CASH FLOWS
(amounts in thousands)

	Year Ended Dec. 31		
	2015	2014	2013
Operating activities			
Net cash provided by operating activities	\$ 704,823	\$ 842,832	\$ 545,177
Investing activities			
Capital contributions to subsidiaries	(820,382)	(422,459)	(535,653)
Investments in the utility money pool	(971,200)	(1,148,000)	(1,778,000)
Return of investments in the utility money pool	987,200	1,204,000	1,706,000
Other, net	(16)	—	—
Net cash used in investing activities	(804,398)	(366,459)	(607,653)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	203,500	(95,500)	297,000
Proceeds from issuance of long-term debt	495,449	—	447,595
Repayment of long-term debt	—	—	(400,000)
Proceeds from issuance of common stock	7,011	180,798	231,767
Dividends paid	(606,574)	(561,411)	(514,042)
Net cash provided by (used in) financing activities	99,386	(476,113)	62,320
Net change in cash and cash equivalents	(189)	260	(156)
Cash and cash equivalents at beginning of period	706	446	602
Cash and cash equivalents at end of period	<u>\$ 517</u>	<u>\$ 706</u>	<u>\$ 446</u>

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED BALANCE SHEETS
(amounts in thousands)

	Dec. 31	
	2015	2014
Assets		
Cash and cash equivalents	\$ 517	\$ 706
Accounts receivable from subsidiaries	315,866	270,921
Other current assets	35,701	47,424
Total current assets	352,084	319,051
Investment in subsidiaries	13,236,758	12,206,575
Other assets	173,136	114,518
Total other assets	13,409,894	12,321,093
Total assets	<u>\$ 13,761,978</u>	<u>\$ 12,640,144</u>
Liabilities and Equity		
Current portion of long-term debt	\$ 450,000	\$ —
Dividends payable	162,410	151,720
Short-term debt	584,000	380,500
Other current liabilities	80,526	65,314
Total current liabilities	1,276,936	597,534
Other liabilities	35,694	30,227
Total other liabilities	35,694	30,227
Commitments and contingencies		
Capitalization		
Long-term debt	1,848,428	1,797,901
Common stockholders' equity	10,600,920	10,214,482
Total capitalization	12,449,348	12,012,383
Total liabilities and equity	<u>\$ 13,761,978</u>	<u>\$ 12,640,144</u>

See Notes to Condensed Financial Statements

NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are Xcel Energy's consolidated statements of common stockholders' equity and OCI in Part II, Item 8.

Basis of Presentation — The condensed financial information of Xcel Energy Inc. is presented to comply with Rule 12-04 of Regulation S-X. Xcel Energy Inc.'s investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity in income of subsidiaries.

As a holding company with no business operations, Xcel Energy Inc.'s assets consist primarily of investments in its utility subsidiaries. Xcel Energy Inc.'s material cash inflows are only from dividends and other payments received from its utility subsidiaries and the proceeds raised from the sale of debt and equity securities. The ability of its utility subsidiaries to make dividend and other payments is subject to the availability of funds after taking into account their respective funding requirements, the terms of their respective indebtedness, the regulations of the FERC under the Federal Power Act, and applicable state laws. Management does not expect maintaining these requirements to have an impact on Xcel Energy Inc.'s ability to pay dividends at the current level in the foreseeable future. Each of its utility subsidiaries, however, is legally distinct and has no obligation, contingent or otherwise, to make funds available to Xcel Energy Inc.

Related Party Transactions — Xcel Energy Inc. presents its related party receivables net of payables. Accounts receivable and payable with affiliates at Dec. 31 were:

(Thousands of Dollars)	2015		2014	
	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Minnesota	\$ 58,952	\$ —	\$ 79,390	\$ —
NSP-Wisconsin	17,391	—	20,117	—
PSCo	114,524	—	38,646	—
SPS	21,357	—	28,062	—
Xcel Energy Services Inc.	73,054	—	75,954	—
Xcel Energy Ventures Inc.	20,003	—	20,082	—
Other subsidiaries of Xcel Energy Inc.	10,585	—	8,670	—
	<u>\$ 315,866</u>	<u>\$ —</u>	<u>\$ 270,921</u>	<u>\$ —</u>

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were \$784 million, \$857 million and \$606 million for the years ended Dec. 31, 2015, 2014 and 2013, respectively. These cash receipts are included in operating cash flows of the condensed statements of cash flows.

Money Pool — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The following tables present money pool lending for Xcel Energy Inc.:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2015
Lending limit	\$ 250
Loan outstanding at period end	—
Average loan outstanding	38
Maximum loan outstanding	99
Weighted average interest rate, computed on a daily basis	0.38%
Weighted average interest rate at end of period	N/A
Money pool interest income	\$ —

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2015	Year Ended Dec. 31, 2014	Year Ended Dec. 31, 2013
Lending limit	\$ 250	\$ 250	\$ 250
Loan outstanding at period end.	—	16	72
Average loan outstanding	27	25	88
Maximum loan outstanding	141	250	243
Weighted average interest rate, computed on a daily basis	0.42%	0.22%	0.30%
Weighted average interest rate at end of period	N/A	0.45	0.25
Money pool interest income	\$ 0.1	\$ 0.1	\$ 0.3

See Xcel Energy's notes to the consolidated financial statements in Part II, Item 8 for other disclosures.

SCHEDULE II

XCEL ENERGY INC. AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DEC. 31, 2015, 2014 AND 2013
(amounts in thousands)

			Additions			
	Balance at Jan. 1		Charged to Costs and Expenses	Charged to Other Accounts ^(a)	Deductions from Reserves ^(b)	Balance at Dec. 31
Allowance for bad debts:						
2015.....	\$ 57,719	\$	36,074	\$ 11,784	\$ 53,689	\$ 51,888
2014.....	53,107		42,765	14,067	52,220	57,719
2013.....	51,394		37,627	14,469	50,383	53,107
NOL and tax credit valuation allowances:						
2015.....	\$ 3,402	\$	2,064	\$ 24,784	\$ 2,571	\$ 27,679
2014.....	3,263		139	—	—	3,402
2013.....	3,314		—	—	51	3,263

^(a) Recovery of amounts previously written off as related to allowance for bad debts. Accrual of valuation allowance for North Dakota ITC, offset to regulatory liability.

^(b) Deductions related to allowance for bad debts relates primarily to write-offs. Reductions to valuation allowances for North Dakota ITC carryforwards primarily due to a consolidated adjustment to the regulatory liability accrual referenced above. Reductions to valuation allowances for NOL carryforwards primarily due to changes in forecasted taxable income.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.

Feb. 19, 2016

By: /s/ TERESA S. MADDEN

Teresa S. Madden

Executive Vice President, Chief Financial Officer

(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the date indicated above.

/s/ BEN FOWKE

Ben Fowke

Chairman, President, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ TERESA S. MADDEN

Teresa S. Madden

Executive Vice President, Chief Financial Officer
(Principal Financial Officer)

/s/ JEFFREY S. SAVAGE

Jeffrey S. Savage

Senior Vice President, Controller
(Principal Accounting Officer)

*

Gail Koziara Boudreaux

Director

*

Richard K. Davis

Director

*

Albert F. Moreno

Director

*

Richard T. O'Brien

Director

*

Christopher J. Policinski

Director

*

James T. Prokopanko

Director

*

A. Patricia Sampson

Director

*

James J. Sheppard

Director

*

David A. Westerlund

Director

*

Kim Williams

Director

*

Timothy V. Wolf

Director

*By: /s/ TERESA S. MADDEN

Teresa S. Madden

Attorney-in-Fact

Shareholder Information

HEADQUARTERS

414 Nicollet Mall, Minneapolis, Minn. 55401

WEBSITE

xcelenergy.com

STOCK TRANSFER AGENT

Wells Fargo Shareowner Services
1110 Centre Pointe Curve, Suite 101
Mendota Heights, Minn. 55120
Telephone: 1-877-778-6786, toll free

REPORTS AVAILABLE ONLINE

Financial reports, including filings with the Securities and Exchange Commission and Xcel Energy's Report to Shareholders, are available online at xcelenergy.com; click on Investor Relations. Other information about Xcel Energy, including our Code of Conduct, Guidelines on Corporate Governance, Corporate Responsibility Report and Committee Charters, also are available at xcelenergy.com.

STOCK EXCHANGE LISTINGS AND TICKER SYMBOL

Common stock is listed on the New York Stock Exchange (NYSE) under the ticker symbol XEL. In newspaper listings, it appears as XcelEngy.

INVESTOR RELATIONS

Website: xcelenergy.com or contact Paul Johnson, Vice President, Investor Relations, at 612-215-4535.

SHAREHOLDER SERVICES

Website: xcelenergy.com or contact Tara Heine, Assistant Corporate Secretary, at 612-215-5391, or email tara.m.heine@xcelenergy.com.

CORPORATE GOVERNANCE

Xcel Energy has filed with the Securities and Exchange Commission certifications of its Chief Executive Officer and Chief Financial Officer pursuant to section 302 of the Sarbanes-Oxley Act of 2002 as exhibits to its Annual Report on Form 10-K for 2015. It has also filed with the New York Stock Exchange the CEO certification for 2015 required by section 303A.12(a) of the New York Stock Exchange's rules relating to compliance with the New York Stock Exchange's corporate governance listing standards.

To contact the Board of Directors, send an email to boardofdirectors@xcelenergy.com.

You also may direct questions to the Corporate Secretary's Department at CorporateSecretary@xcelenergy.com.



Xcel Energy Board of Directors (l to r): Gail Boudreaux, Timothy Wolf, Richard Davis, Albert Moreno, Kim Williams, David Westerlund, Richard O'Brien, James Sheppard, Patricia Sampson, Ben Fowke, James Prokopanko, Christopher Policinski.

Xcel Energy Board of Directors

Gail Koziara Boudreaux^{2, 4}

CEO and Founder, GKB Global Health, LLC
Former CEO of UnitedHealthcare

Richard K. Davis³

Lead Independent Director
Chairman and CEO, U.S. Bancorp

Ben Fowke

Chairman, President and CEO
Xcel Energy Inc.

Albert F. Moreno^{1, 4}

Retired Senior Vice President
and General Counsel
Levi Strauss & Co.

Richard T. O'Brien^{1, 4}

Former President and CEO
Boart Longyear Limited

Christopher J. Policinski^{2, 3}

President and CEO
Land O' Lakes, Inc.

James Prokopanko^{1, 4}

Retired President and CEO
The Mosaic Company

A. Patricia Sampson^{1, 3}

CEO, President and Owner
The Sampson Group, Inc.

James J. Sheppard^{2, 4}

Independent Consultant
Former Senior Vice President
and Chief Nuclear Officer
Southern California Edison

David A. Westerlund^{2, 3}

Retired Executive Vice President,
Administration and Corporate Secretary
Ball Corporation

Kim Williams^{1, 3}

Retired Partner
Wellington Management Company LLP

Timothy V. Wolf^{1, 4}

President
Wolf Interests, Inc.

Board Committees:

1. Audit
2. Governance, Compensation
and Nominating
3. Finance
4. Operations, Nuclear, Environmental
and Safety

Fiscal Agents

XCEL ENERGY INC.

Transfer Agent, Registrar, Dividend Distribution, Common Stock

Wells Fargo Shareowner Services, 1110 Centre Pointe Curve, Suite 101
Mendota Heights, Minn. 55120

Trustee – Bonds

Wells Fargo Bank, N.A., Corporate Trust Services
150 East 42nd Street, 40th Floor, New York, N.Y. 10017



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THIS FILING IS

Item 1: ☒ An Initial (Original) Submission OR ☐ Resubmission No. _____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)



FERC FINANCIAL REPORT

FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)

Northern States Power Company (Minnesota)

Year/Period of Report

End of 2015/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

- (1) one million megawatt hours of total annual sales,
- (2) 100 megawatt hours of annual sales for resale,
- (3) 500 megawatt hours of annual power exchanges delivered, or
- (4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: <http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp>. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

- a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
- b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

<u>Reference Schedules</u>	<u>Pages</u>
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

- e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of _____, we have also reviewed schedules

_____ of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

- (f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at <http://www.ferc.gov/help/how-to.asp>.

- (g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from <http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf> and <http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas>.

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

- a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and
- b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

- I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.
- II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.
- III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.
- IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.
- V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).
- VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.
- VII. For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.
- VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the

termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power;

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed..."

General Penalties

The Commission may assess up to \$1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION		
01 Exact Legal Name of Respondent Northern States Power Company (Minnesota)		02 Year/Period of Report End of <u>2015/Q4</u>
03 Previous Name and Date of Change <i>(if name changed during year)</i> / /		
04 Address of Principal Office at End of Period <i>(Street, City, State, Zip Code)</i> 414 Nicollet Mall, Minneapolis, MN 55401		
05 Name of Contact Person Jeffrey S. Savage		06 Title of Contact Person Sr. Vice Pres., Controller
07 Address of Contact Person <i>(Street, City, State, Zip Code)</i> 414 Nicollet Mall, Minneapolis, MN 55401		
08 Telephone of Contact Person, <i>Including Area Code</i> (612) 330-5658	09 This Report Is (1) ☒ An Original (2) ☐ A Resubmission	10 Date of Report <i>(Mo, Da, Yr)</i> 04/11/2016
ANNUAL CORPORATE OFFICER CERTIFICATION		
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.		
01 Name Jeffrey S. Savage	03 Signature Jeffrey S. Savage	04 Date Signed <i>(Mo, Da, Yr)</i> 04/11/2016
02 Title Senior Vice President, Controller		
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

LIST OF SCHEDULES (Electric Utility)			
Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".			
Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	None
32	Capital Stock Expense	254	None
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	None
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	None
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	None
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	None
66	Generating Plant Statistics Pages	410-411	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: ☒ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Jeffrey S. Savage
Senior Vice President, Controller
414 Nicollet Mall
Minneapolis, MN 55401

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Northern States Power Co. (a Minnesota corporation) was incorporated in the state of Minnesota on March 8, 2000.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable.

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

During the year 2015, the respondent furnished electric utility and natural gas utility service in the states of Minnesota and North Dakota and electric utility and intrastate natural gas transportation service in the state of South Dakota.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

- (1) ☐ Yes...Enter the date when such independent accountant was initially engaged:
 (2) ☒ No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) ☒ An Original (2) ☐ A Resubmission	04/11/2016	End of 2015/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Northern States Power Co. (a Minnesota corporation) is a first tier subsidiary of Xcel Energy Inc.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.

2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.

3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.

2. Direct control is that which is exercised without interposition of an intermediary.

3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.

4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	NSP Nuclear Corp	Holds NSP's interest in	100	
2		Nuclear Mgmt Co. LLC		
3	Nuclear Mgmt Co. LLC	Manages nuclear power plants	100	
4	Private Fuel Storage, LLC	Nuclear waste storage	32.8	
5	United Power and Land Co.	Real estate holdings	100	
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Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
OFFICERS					
1. Report below the name, title and salary for each executive officer whose salary is \$50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions. 2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.					
Line No.	Title (a)	Name of Officer (b)		Salary for Year (c)	
1	Chairman of the Board, Chief Executive Officer	Ben Fowke		528,209	
2	President	Christopher B. Clark		285,000	
3	Executive Vice President, Chief Financial Officer	Teresa S. Madden		228,188	
4	Executive Vice President	Marvin E. McDaniel, Jr.		222,529	
5	Executive Vice President	Kent T. Larson		205,937	
6	Executive Vice President, General Counsel	Scott M. Wilensky		220,029	
7	Senior Vice President, Corporate Secretary	Judy M. Pofert		145,656	
8	Senior Vice President, Chief Nuclear Officer	Timothy J. O'Connor		490,000	
9	Senior Vice President, Controller	Jeffrey S. Savage		113,288	
10	Vice President, Treasurer	George E. Tyson II		73,277	
11					
12	Salaries represent NSP-Minnesota's allocation of				
13	officers' salaries greater than \$50,000 for the period				
14	of time that was served as an officer for				
15	NSP-Minnesota.				
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Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 104 Line No.: 10 Column: b

Brian J. Van Abel replaced George E. Tyson II as Vice President, Treasurer, effective July 27, 2015.

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
DIRECTORS					
1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.					
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.					
Line No.	Name (and Title) of Director (a)			Principal Business Address (b)	
1	Ben Fowke, Chairman of the Board, Chief Executive Officer			414 Nicollet Mall, Suite 500, Minneapolis, MN 55401	
2	Teresa S. Madden, Executive Vice President, CFO			414 Nicollet Mall, Suite 500, Minneapolis, MN 55401	
3	Christopher B. Clark, President			414 Nicollet Mall, Suite 500, Minneapolis, MN 55401	
4	Marvin E. McDaniel, Jr., Executive Vice President			414 Nicollet Mall, Suite 500, Minneapolis, MN 55401	
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Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 105 Line No.: 1 Column: a

Ben Fowke was elected as Chief Executive Officer effective Jan. 1, 2015.

Schedule Page: 105 Line No.: 3 Column: a

Christopher B. Clark was elected as President effective Jan. 1, 2015.

Schedule Page: 105 Line No.: 4 Column: a

Marvin E. McDaniel, Jr. was elected as Director, Executive Vice President effective Jan.1, 2015.

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
INFORMATION ON FORMULA RATES FERC Rate Schedule/Tariff Number FERC Proceeding					
Does the respondent have formula rates?				☒ Yes ☐ No	
1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.					
Line No.	FERC Rate Schedule or Tariff Number		FERC Proceeding		
1	FERC Electric Tariff, Third Revised Volume No. 1		ER07-1415-000 - Order Granting Incentives,		
2	(Midwest Independent Transmission System		and Accepting Proposed Rate Formula		
3	Operator, Inc. Open Access Transmission and		Modifications, Subject to Conditions, Issued		
4	Energy Markets Tariff, Attachment O-NSP)		December 21, 2007, Accession No.		
5			20071221-3012		
6					
7	FERC Electric Tariff, Fourth Revised Volume No. 1		ER10-541-000 - Approval of Tariff Revisions to		
8	(Midwest Independent Transmission System		Attachment O-NSP, Issued February 26, 2010,		
9	Operator, Inc. Open Access Transmission and		Accession No. 20100226-3041.		
10	Energy Markets Tariff, Attachment O-NSP)				
11					
12	FERC Electric Tariff updated effective 01-01-2012		ER12-297-000 - Approval of Tariff Revisions to		
13	(Midwest Independent Transmission System		Attachment O-NSP, Issued December 21, 2011,		
14	Operator, Inc. Open Access Transmission and		Accession No. 20111221-3033.		
15	Energy Markets Tariff, Attachment O-NSP)				
16					
17	FERC Electric Tariff updated effective 01-01-2013		ER13-674-000/001/002 Approval of Tariff Revisions		
18	(Midwest Independent Transmission System		to Attachment O-NSP, Issued March 20, 2013,		
19	Operator, Inc. Open Access Transmission and		Accession No. 20130320-3014		
20	Energy Markets Tariff, Attachment O-NSP)				
21					
22	FERC Electric Tariff updated effective 11-18-2013		ER14-421-000/001 Approval of Tariff Revisions		
23	(Midcontinent Independent System		to Attachment O-NSP, Issued March 11, 2014,		
24	Operator, Inc. Open Access Transmission and		Accession No. 20140311-3041		
25	Energy Markets Tariff, Attachment O-NSP)				
26					
27	FERC Electric Tariff updated effective 01-06-2015		ER15-358-000/001 Approval of Tariff Revisions		
28	(Midcontinent Independent System		to Attachment O-NSP, Issued January 5, 2015,		
29	Operator, Inc. Open Access Transmission and		Accession No. 20150105-3035		
30	Energy Markets Tariff, Attachment O-NSP)				
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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of <u>2015/Q4</u>

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	☒ Yes ☐ No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20160314-5241	03/14/2016	ER16-1171-000	See footnote	FERC Electric Tariff updated effective
2					01-06-2015 (Midcontinent Independent
3					System Operator, Inc. Open
4					Access Transmission and Energy
5					Markets Tariff, Attachment O-NSP)
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Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 1061 Line No.: 1 Column: d

Annual Informational Attachment 0 filing of NSP-Minnesota and NSP-Wisconsin under ER16-1171.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	111	Comp Balance Sheet Assets and Other Dfrd Debits	(c)	57
2	204	Electric Plant in Service (Acct 101, 102, 103,106)	(g)	5, 46, 58, 75, 99
3	214	Electric Plant Held for Future Use (Acct 105)	(d)	46
4	216.1	Construction Work in Progress- Electric (Acct 107)	(a)	21
5	219	Accum Prov for Depr of Elect Util Plant (Acct 108)	(c)	20-26, 28
6	227	Materials and Supplies	(a)	18
7	234	Accumulated Deferred Income Taxes (Acct 190)	(b)	8
8	267	Accum. Deferred Investment Tax Credits (Acct 225)	(h)	8
9	269	Other Deferred Credits (Acct 253)	(d), (e)	35
10	269	Other Deferred Credits (Acct 253)	(a)	45
11	272	Accumulated Deferred Income Taxes (Acct 281)	(b)	8
12	274	Accumulated Deferred Income Taxes (Acct 282)	(b)	2
13	276	Accumulated Deferred Income Taxes (Acct 283)	(b)	3
14	300	Electric Operating Revenues (Acct 400)	(b)	19
15	310.1	Sales for Resale (Acct 447)	(a)	10
16	321	Electric Operation and Maintenance Expenses	(c)	112
17	328	Transmission of Electricity for Others	(a)	19
18	356.2	Common Utility Plant and Expenses	n/a	n/a
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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report 04/11/2016	Year/Period of Report End of 2015/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR			
Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears. - Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact. - Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization. - Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission. - Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization. - Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc. - Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee. - Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments. - State the estimated annual effect and nature of any important wage scale changes during the year. - State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year. - Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest. (Reserved.) - If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page. - Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period. - In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.			
PAGE 108 INTENTIONALLY LEFT BLANK SEE PAGE 109 FOR REQUIRED INFORMATION.			

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. Franchise – The following franchises were acquired from the representative local government body without payment of consideration:

City	State	Utility	Expiration
St. Louis Park	Minn.	Electric	Dec. 31, 2016 (extension)
Spring Lake Park	Minn.	Electric	Jan. 4, 2035
Maple Plain	Minn.	Electric	Jan. 25, 2035
Moorhead	Minn.	Electric	Feb. 8, 2035
Stillwater	Minn.	Electric	Feb. 16, 2035
Stillwater	Minn.	Gas	Feb. 16, 2035
Ulen	Minn.	Gas	April 13, 2035
St. Mary's Point	Minn.	Electric	June 1, 2035
Maplewood	Minn.	Gas	June 7, 2035
Hamburg	Minn.	Electric	June 15, 2035
Green Isle	Minn.	Electric	July 13, 2035
Lakeland	Minn.	Electric	July 20, 2035
Jordan	Minn.	Electric	Aug. 2, 2035
Gibbon	Minn.	Electric	Aug. 4, 2035
Berthold	N.D.	Electric	Sept. 8, 2035
Des Lacs	N.D.	Electric	Oct. 4, 2035
Butterfield	Minn.	Electric	Oct. 14, 2035
Edina	Minn.	Electric	Nov. 3, 2035
Lakeville	Minn.	Electric	Dec. 6, 2035
Bloomington	Minn.	Electric	Dec. 20, 2035

2. Acquisitions

None

3. Purchase or sale of an operating unit or system

None

4. Important leaseholds acquired or given, assigned or surrendered

None

5. Important extension or reduction of transmission or distribution system

None.

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Northern States Power Company (Minnesota)			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

6. Obligations incurred as a result of securities or assumption of liabilities

See Note 3 of the Financial Statements on Page 123 for disclosures regarding short-term borrowings, long-term debt and other financing activities.

7. Changes in articles of incorporation and amendments to charter

None

8. Wage scale changes

- 1) Union Employees – Merit base increase of 2.50 percent effective Jan. 1, 2015.
Metro West and Metro East – Merit base increase of 1.00 percent for 99 employees effective Dec. 6, 2015.
- 2) Non-Union Employees – Merit base increase of 3.00 percent effective March 16, 2015.

9. Legal proceedings

See Note 9 of the Financial Statements on page 123 for disclosures regarding material legal proceedings.

10. Other materially important transactions with associates

None.

11. (Reserved)

12. Important changes

None.

13. Changes in officers, directors, major security holders and voting powers

David M. Sparby resigned as President and Chief Executive Officer effective Dec. 31, 2014.
Ben Fowke was elected as Chief Executive Officer effective Jan. 1, 2015.
Christopher B. Clark was elected as President and Director effective Jan. 1, 2015.
Marvin E. McDaniel, Jr. was elected as Director, Executive Vice President effective Jan. 1, 2015.
George E. Tyson II resigned as Vice President and Treasurer effective July 26, 2015.
Brian J. Van Abel was elected as Vice President, Treasurer effective July 27, 2015.

14. Cash management programs

Not applicable as proprietary capital ratio is greater than 30 percent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) ☒ An Original (2) ☐ A Resubmission	04/11/2016	End of <u>2015/Q4</u>

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	18,298,081,598	16,723,770,058
3	Construction Work in Progress (107)	200-201	548,033,874	725,095,753
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		18,846,115,472	17,448,865,811
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	6,940,949,706	6,587,866,288
6	Net Utility Plant (Enter Total of line 4 less 5)		11,905,165,766	10,860,999,523
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	148,727,046	191,187,454
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	365,168
9	Nuclear Fuel Assemblies in Reactor (120.3)		525,918,125	527,866,883
10	Spent Nuclear Fuel (120.4)		1,772,605,603	1,628,002,046
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	2,063,654,320	1,957,229,917
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		383,596,454	390,191,634
14	Net Utility Plant (Enter Total of lines 6 and 13)		12,288,762,220	11,251,191,157
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		13,167,811	11,406,468
19	(Less) Accum. Prov. for Depr. and Amort. (122)		8,606,540	7,767,132
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	2,553,060	2,664,672
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		34,057,691	31,395,878
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,724,399,969	1,704,337,082
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		22,333,814	15,434,081
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,787,905,805	1,757,471,049
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		22,170,934	30,045,647
36	Special Deposits (132-134)		250,000	0
37	Working Fund (135)		128,040	131,440
38	Temporary Cash Investments (136)		20,183,604	10,095,192
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		278,196,766	354,397,989
41	Other Accounts Receivable (143)		48,366,355	90,443,676
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		20,750,400	22,937,437
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		44,239,696	34,648,471
45	Fuel Stock (151)	227	107,654,333	80,824,146
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	200,142,370	156,079,440
49	Merchandise (155)	227	738,863	1,286,223
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	6,628	10,274

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Northern States Power Company (Minnesota)	(1) ☒ An Original (2) ☐ A Resubmission	04/11/2016	End of <u>2015/Q4</u>

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		28,936,798	46,169,956
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		6,436,816	5,916,779
57	Prepayments (165)		60,091,770	73,774,783
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		728,876	666,975
61	Accrued Utility Revenues (173)		227,101,551	251,587,177
62	Miscellaneous Current and Accrued Assets (174)		2,352,888	2,601,739
63	Derivative Instrument Assets (175)		41,274,552	75,598,321
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		22,333,814	15,434,081
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,045,916,626	1,175,906,710
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		37,700,632	33,601,977
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	68,027,230	70,884,203
72	Other Regulatory Assets (182.3)	232	3,058,047,442	2,828,379,652
73	Prelim. Survey and Investigation Charges (Electric) (183)		258,448	20
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	54,088,311	96,612,407
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		15,368,020	17,295,831
82	Accumulated Deferred Income Taxes (190)	234	1,000,619,754	812,688,663
83	Unrecovered Purchased Gas Costs (191)		22,739,437	47,716,611
84	Total Deferred Debits (lines 69 through 83)		4,256,849,274	3,907,179,364
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		19,379,433,925	18,091,748,280

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Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 110 Line No.: 57 Column: c

Prepayments (Account No. 165). The Form 1 reports prepayments at the total Company level, at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of the year prepayments balance in the formula. In addition, since prepayments are reported in the Form 1 at the total Company level, they are allocated to the electric utility based on the ratio of electric net plant to the sum of electric and gas net plant as reported in the Form 1, page 200. The formula allocates the electric prepayments to the transmission function using a gross plant allocator.

The balance at Dec. 31, 2015 includes \$33,756,726 for income taxes. This balance was largely driven by a reserve for the Internal Revenue Service audits, a portion of which is currently in Appeals, and an overpayment for 2015 income taxes. NSP-Minnesota expects the overpayment for 2015 will be settled in 2016 after the Xcel Energy Inc. extensions and tax returns are filed.

Schedule Page: 110 Line No.: 57 Column: d

Northern States Power Co. (a Minnesota corporation)(NSP-Minnesota's) Prepayments (Account No. 165) balance at Dec. 31, 2014, included \$24,674,934 for income taxes. This balance was largely driven by a reserve for the Internal Revenue Service audit which was pending Appeals and an overpayment for 2014 income taxes. NSP-Minnesota's overpayment for 2014 income taxes was settled in 2015 after the Xcel Energy extensions and tax returns were filed.

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)				
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	10,000	10,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		3,323,810,404	2,961,654,221
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	1,867,056,192	1,764,950,471
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-2,729,903	-2,627,733
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-21,081,338	-20,814,248
16	Total Proprietary Capital (lines 2 through 15)		5,167,065,355	4,703,172,711
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,550,000,000	4,200,000,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	33,400	45,933
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		15,911,324	11,364,486
24	Total Long-Term Debt (lines 18 through 23)		4,534,122,076	4,188,681,447
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		448,244	811,142
29	Accumulated Provision for Pensions and Benefits (228.3)		302,990,000	307,742,000
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		62,085,623	85,052,890
32	Long-Term Portion of Derivative Instrument Liabilities		128,212,719	134,980,074
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	56,330
34	Asset Retirement Obligations (230)		2,331,092,414	2,186,173,899
35	Total Other Noncurrent Liabilities (lines 26 through 34)		2,824,829,000	2,714,816,335
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		223,000,000	142,000,000
38	Accounts Payable (232)		393,075,133	498,355,284
39	Notes Payable to Associated Companies (233)		1,450,000	1,500,000
40	Accounts Payable to Associated Companies (234)		59,784,707	50,544,423
41	Customer Deposits (235)		92,148,574	43,113,307
42	Taxes Accrued (236)	262-263	203,255,169	193,628,086
43	Interest Accrued (237)		66,882,734	61,338,792
44	Dividends Declared (238)		73,497,550	77,802,375
45	Matured Long-Term Debt (239)		0	0

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		20,678,151	26,178,461
48	Miscellaneous Current and Accrued Liabilities (242)		31,194,364	12,228,864
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		145,310,626	147,208,879
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		128,212,719	134,980,074
52	Derivative Instrument Liabilities - Hedges (245)		112,812	121,360
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	56,330
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,182,177,101	1,118,983,427
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		11,992,608	9,328,626
57	Accumulated Deferred Investment Tax Credits (255)	266-267	25,837,882	27,566,888
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	315,499,429	315,569,235
60	Other Regulatory Liabilities (254)	278	1,733,392,392	1,835,077,482
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	34,967,609	37,729,105
63	Accum. Deferred Income Taxes-Other Property (282)		3,330,468,638	2,939,040,850
64	Accum. Deferred Income Taxes-Other (283)		219,081,835	201,782,174
65	Total Deferred Credits (lines 56 through 64)		5,671,240,393	5,366,094,360
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		19,379,433,925	18,091,748,280

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.

2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.

3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.

4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.

5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)

6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.

7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	4,769,967,410	5,002,197,693		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,970,243,905	3,316,402,203		
5	Maintenance Expenses (402)	320-323	281,924,543	300,644,812		
6	Depreciation Expense (403)	336-337	521,547,012	482,013,738		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	9,781,448	7,553,759		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	46,025,861	40,759,246		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		5,777,630			
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		23,743,966	29,585,368		
13	(Less) Regulatory Credits (407.4)		230,919,923	237,775,111		
14	Taxes Other Than Income Taxes (408.1)	262-263	230,729,787	223,531,674		
15	Income Taxes - Federal (409.1)	262-263	-34,573,036	-870,452		
16	- Other (409.1)	262-263	-27,816,466	17,305,663		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	800,762,622	596,199,165		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	564,404,724	419,115,069		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,729,006	-1,734,848		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)			173,039		
22	(Less) Gains from Disposition of Allowances (411.8)		1,727,724	828,138		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		108,840,618	90,169,126		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,138,206,513	4,444,014,175		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		631,760,897	558,183,518		

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016		Year/Period of Report End of 2015/Q4	
STATEMENT OF INCOME FOR THE YEAR (Continued)							
9. Use page 122 for important notes regarding the statement of income for any account thereof. 10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases. 11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts. 12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122. 13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes. 14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports. 15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.							
ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY			
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.	
						1	
4,218,157,309	4,239,532,104	551,810,101	762,665,589			2	
						3	
2,545,922,720	2,692,696,133	424,321,185	623,706,070			4	
273,907,874	292,491,096	8,016,669	8,153,716			5	
482,470,802	445,074,422	39,076,210	36,939,316			6	
9,540,543	7,552,093	240,905	1,666			7	
41,720,228	36,099,710	4,305,633	4,659,536			8	
						9	
5,777,630						10	
						11	
21,372,852	29,249,034	2,371,114	336,334			12	
229,640,386	237,748,381	1,279,537	26,730			13	
209,109,846	200,716,167	21,619,941	22,815,507			14	
-43,487,868	3,278,019	8,914,832	-4,148,471			15	
-29,585,789	17,032,228	1,769,323	273,435			16	
743,711,761	501,712,241	57,050,861	94,486,924			17	
510,773,401	348,109,628	53,631,323	71,005,441			18	
-1,450,702	-1,458,907	-278,304	-275,941			19	
						20	
	173,039					21	
1,727,724	828,138					22	
						23	
107,801,987	90,144,063	1,038,631	25,063			24	
3,624,670,373	3,728,073,191	513,536,140	715,940,984			25	
593,486,936	511,458,913	38,273,961	46,724,605			26	

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016		Year/Period of Report End of 2015/Q4	
STATEMENT OF INCOME FOR THE YEAR (continued)							
Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)	
			Current Year (c)	Previous Year (d)			
27	Net Utility Operating Income (Carried forward from page 114)		631,760,897	558,183,518			
28	Other Income and Deductions						
29	Other Income						
30	Nonutility Operating Income						
31	Revenues From Merchandising, Jobbing and Contract Work (415)						
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)						
33	Revenues From Nonutility Operations (417)		27,924,349	28,442,748			
34	(Less) Expenses of Nonutility Operations (417.1)		21,901,881	21,552,098			
35	Nonoperating Rental Income (418)						
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-102,171	-57,074			
37	Interest and Dividend Income (419)		762,097	1,082,734			
38	Allowance for Other Funds Used During Construction (419.1)		26,819,016	23,788,090			
39	Miscellaneous Nonoperating Income (421)		14,546,734	18,284,381			
40	Gain on Disposition of Property (421.1)		206	248,098			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		48,048,350	50,236,879			
42	Other Income Deductions						
43	Loss on Disposition of Property (421.2)		60,021	792			
44	Miscellaneous Amortization (425)						
45	Donations (426.1)		1,285,857	5,858,832			
46	Life Insurance (426.2)		-1,745,889	-2,635,997			
47	Penalties (426.3)		39,512	-406,818			
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,130,628	2,428,763			
49	Other Deductions (426.5)		223,033	2,799,277			
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,993,162	8,044,849			
51	Taxes Applicable to Other Income and Deductions						
52	Taxes Other Than Income Taxes (408.2)	262-263	179,703	179,150			
53	Income Taxes-Federal (409.2)	262-263	1,174,412	4,731,951			
54	Income Taxes-Other (409.2)	262-263	24,141,180	7,945,338			
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	39,282,113	40,190,913			
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	56,031,060	46,534,395			
57	Investment Tax Credit Adj.-Net (411.5)						
58	(Less) Investment Tax Credits (420)						
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		8,746,348	6,512,957			
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		37,308,840	35,679,073			
61	Interest Charges						
62	Interest on Long-Term Debt (427)		199,692,091	189,762,925			
63	Amort. of Debt Disc. and Expense (428)		3,809,419	3,583,929			
64	Amortization of Loss on Reacquired Debt (428.1)		1,927,811	1,927,811			
65	(Less) Amort. of Premium on Debt-Credit (429)						
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)						
67	Interest on Debt to Assoc. Companies (430)		217,456	194,906			
68	Other Interest Expense (431)		3,395,525	4,189,087			
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		12,724,862	10,711,165			
70	Net Interest Charges (Total of lines 62 thru 69)		196,317,440	188,947,493			
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		472,752,297	404,915,098			
72	Extraordinary Items						
73	Extraordinary Income (434)						
74	(Less) Extraordinary Deductions (435)		115,913,047				
75	Net Extraordinary Items (Total of line 73 less line 74)		-115,913,047				
76	Income Taxes-Federal and Other (409.3)	262-263					
77	Extraordinary Items After Taxes (line 75 less line 76)		-115,913,047				
78	Net Income (Total of line 71 and 77)		356,839,250	404,915,098			

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Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 114 Line No.: 12 Column: c

	Electric	Gas
Minnesota Renewable Development Fund	\$ 17,279,149	
Minnesota Transmission Cost Recovery	1,884,453	
North Dakota Transmission Cost Recovery	1,419,327	
Minnesota Gas Utility Infrastructure		1,306,717
Minnesota State Energy Policy	213,942	1,064,397
Sherco Unit 3 Depreciation Deferral	466,162	
North and South Dakota Private Fuel Storage	109,819	
	<u>\$ 21,372,852</u>	<u>\$ 2,371,114</u>

Schedule Page: 114 Line No.: 12 Column: d

	Electric	Gas
Minnesota Renewable Development Fund	\$ 23,146,919	
Minnesota Renewable Energy Standard	3,639,532	
South Dakota Infrastructure	1,417,089	
Sherco Unit 3 Depreciation Deferral	503,130	
South Dakota Transmission Cost Recovery	317,173	
Private Fuel Storage	220,357	
Minnesota Net Operating Loss Tracker	3,803	
Minnesota State Energy Policy	1,031	336,334
	<u>\$ 29,249,034</u>	<u>\$ 336,334</u>

Schedule Page: 114 Line No.: 13 Column: c

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	\$ 117,342,530	\$ 1,279,537
Theoretical Depreciation Reserve Surplus	75,810,719	
Department of Energy Refund Amortization	25,734,695	
Minnesota Renewable Energy Standard	8,166,398	
South Dakota Infrastructure	1,972,777	
North Dakota Renewable Energy Rider	225,175	
South Dakota Transmission Cost Recovery	388,092	
	<u>\$ 229,640,386</u>	<u>\$ 1,279,537</u>

Schedule Page: 114 Line No.: 13 Column: d

	Electric	Gas
Theoretical Depreciation Reserve Surplus	\$ 125,619,772	
Asset Retirement Obligation Regulatory Credits	97,696,155	26,730
Minnesota Transmission Cost Recovery	12,269,706	
North Dakota Transmission Cost Recovery	2,137,036	
Private Fuel Storage	25,712	
	<u>\$ 237,748,381</u>	<u>\$ 26,730</u>

Schedule Page: 114 Line No.: 46 Column: c

Income on Company Owned Life Insurance.

Schedule Page: 114 Line No.: 46 Column: d

Income on Company Owned Life Insurance.

Schedule Page: 114 Line No.: 74 Column: c

Account No. 435 activity is related to the March 2015 regulatory decision for the Monticello LCM/EPU project. The pre-tax components of the entry are shown below, and

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Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

an estimated tax benefit of \$47,290,205 on this loss is recorded in Account No. 411.1
Provision for Deferred Income Taxes-Credit. See Note 8 to the Financial Statements.

Account No. 449.1	\$ 8,011,783
Account No. 431	301,065
Account No. 435	115,913,047
	<u>\$ 124,225,895</u>

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STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.

2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.

3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)

4. State the purpose and amount of each reservation or appropriation of retained earnings.

5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.

6. Show dividends for each class and series of capital stock.

7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.

8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.

9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		1,764,872,848	1,638,402,677
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11	Rounding			(1)
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			(1)
16	Balance Transferred from Income (Account 433 less Account 418.1)		356,941,421	404,972,172
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-254,835,700	(278,502,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-254,835,700	(278,502,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,866,978,569	1,764,872,848
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

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STATEMENT OF CASH FLOWS					
(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc. (2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet. (3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid. (4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.					
Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)		
1	Net Cash Flow from Operating Activities:				
2	Net Income (Line 78(c) on page 117)	356,839,250	404,915,098		
3	Noncash Charges (Credits) to Income:				
4	Depreciation and Depletion	477,700,172	408,995,983		
5	Amortization of Nuclear Fuel	106,424,403	114,542,138		
6	Amortization of Premium, Discount and Debt Expense	5,737,230	5,511,740		
7	Monticello LCM/EPU Loss	124,225,895			
8	Deferred Income Taxes (Net)	219,608,951	170,740,614		
9	Investment Tax Credit Adjustment (Net)	-1,729,006	-1,734,848		
10	Net (Increase) Decrease in Receivables	106,860,755	-122,136,015		
11	Net (Increase) Decrease in Inventory	-53,471,390	-10,284,967		
12	Net (Increase) Decrease in Allowances Inventory	3,646			
13	Net Increase (Decrease) in Payables and Accrued Expenses	-8,067,823	-45,530,432		
14	Net (Increase) Decrease in Other Regulatory Assets	21,586,568	58,222,017		
15	Net Increase (Decrease) in Other Regulatory Liabilities	-91,073,024	124,145,572		
16	(Less) Allowance for Other Funds Used During Construction	26,819,016	23,788,090		
17	(Less) Undistributed Earnings from Subsidiary Companies	-102,171	-57,074		
18	Other: (Increase) Decrease in Accrued Utility Revenues	24,485,626	3,825,195		
19	Other: Net Realized and Unrealized Hedging and Derivatives Transaction	16,074,870	5,022,827		
20	Other: Changes in Other Current Assets and Liabilities	65,666,702	33,327,613		
21	Other: Changes in Noncurrent Liabilities and Deferred Amounts	-24,047,149	-13,421,332		
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,320,108,831	1,112,410,187		
23					
24	Cash Flows from Investment Activities:				
25	Construction and Acquisition of Plant (including land):				
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,678,904,907	-994,087,531		
27	Gross Additions to Nuclear Fuel	-103,243,281	-160,792,070		
28	Gross Additions to Common Utility Plant	-72,739,940	-87,057,724		
29	Gross Additions to Nonutility Plant				
30	(Less) Allowance for Other Funds Used During Construction	-26,819,016	-23,788,090		
31	Other: Proceeds from Insurance Recoveries	27,237,056	6,000,000		
32					
33					
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,800,832,056	-1,212,149,235		
35					
36	Acquisition of Other Noncurrent Assets (d)				
37	Proceeds from Disposal of Noncurrent Assets (d)				
38					
39	Investments in and Advances to Assoc. and Subsidiary Companies	-140,000	-240,000		
40	Contributions and Advances from Assoc. and Subsidiary Companies	90,000			
41	Disposition of Investments in (and Advances to)				
42	Associated and Subsidiary Companies				
43	Investments in Utility Money Pool Arrangement	-385,900,000	-432,000,000		
44	Purchase of Investment Securities (a)				
45	Proceeds from Sales of Investment Securities (a)				

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STATEMENT OF CASH FLOWS					
(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc. (2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet. (3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid. (4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.					
Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)		
46	Loans Made or Purchased				
47	Collections on Loans				
48	Repayments from Utility Money Pool Arrangement	385,900,000	432,000,000		
49	Net (Increase) Decrease in Receivables				
50	Net (Increase) Decrease in Inventory				
51	Net (Increase) Decrease in Allowances Held for Speculation				
52	Net Increase (Decrease) in Payables and Accrued Expenses				
53	Other: Miscellaneous Other Investing Activities	-2,661,813	-3,066,067		
54	Other: Purchase of Investments in External Decommissioning Fund	-1,257,924,231	-595,568,687		
55	Other: Proceeds from Sale of Investments in External Decommission Fnd	1,236,873,138	588,430,218		
56	Net Cash Provided by (Used in) Investing Activities				
57	Total of lines 34 thru 55)	-1,824,594,962	-1,222,593,771		
58					
59	Cash Flows from Financing Activities:				
60	Proceeds from Issuance of:				
61	Long-Term Debt (b)	587,545,088	295,338,642		
62	Preferred Stock				
63	Common Stock				
64	Other: Capital Contributions by Parent	347,304,401	95,050,783		
65	Other: Borrowings Under Utility Money Pool Arrangement	294,500,000	340,000,000		
66	Net Increase in Short-Term Debt (c)	81,000,000	11,000,000		
67	Other (provide details in footnote):				
68					
69					
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,310,349,489	741,389,425		
71					
72	Payments for Retirement of:				
73	Long-term Debt (b)	-250,012,534			
74	Preferred Stock		-1,777		
75	Common Stock				
76	Other: Repayments Under Utility Money Pool Arrangement	-294,500,000	-374,000,000		
77					
78	Net Decrease in Short-Term Debt (c)				
79					
80	Dividends on Preferred Stock				
81	Dividends on Common Stock	-259,140,525	-259,451,377		
82	Net Cash Provided by (Used in) Financing Activities				
83	(Total of lines 70 thru 81)	506,696,430	107,936,271		
84					
85	Net Increase (Decrease) in Cash and Cash Equivalents				
86	(Total of lines 22,57 and 83)	2,210,299	-2,247,313		
87					
88	Cash and Cash Equivalents at Beginning of Period	40,272,279	42,519,592		
89					
90	Cash and Cash Equivalents at End of period	42,482,578	40,272,279		

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 120 Line No.: 21 Column: b

Changes in Noncurrent Liabilities and Deferred Amounts

Change in pension and employee benefit obligation	\$ (25,861,043)
Change in deferred debits	67,242,841
Change in deferred credits	(33,790,123)
Change in noncurrent liabilities	(31,638,824)
	<u>\$ (24,047,149)</u>

Schedule Page: 120 Line No.: 21 Column: c

Changes in Noncurrent Liabilities and Deferred Amounts

Change in pension and employee benefit obligation	\$ (40,650,152)
Change in deferred debits	(36,844,767)
Change in deferred credits	(13,313,166)
Change in noncurrent liabilities	77,386,753
	<u>\$ (13,421,332)</u>

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Cash and Working Funds (130)	\$ 0
Cash (131)	22,170,934
Working Fund (135)	128,040
Temporary Cash Investments (136)	20,183,604
Cash and Cash Equivalents at End of Period	<u>\$ 42,482,578</u>

Schedule Page: 120 Line No.: 90 Column: c

Cash and Working Funds (130)	\$ 0
Cash (131)	30,045,647
Working Fund (135)	131,440
Temporary Cash Investments (136)	10,095,192
Cash and Cash Equivalents at End of Period	<u>\$ 40,272,279</u>

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NOTES TO FINANCIAL STATEMENTS 1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement. 2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock. 3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof. 4. Where Accounts 189, Unamortized Loss on Recquired Debt, and 257, Unamortized Gain on Recquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts. 5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions. 6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein. 7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted. 8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred. 9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.
PAGE 122 INTENTIONALLY LEFT BLANK SEE PAGE 123 FOR REQUIRED INFORMATION.

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Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

1. Summary of Significant Accounting Policies

Business and System of Accounts — Northern States Power Co., a Minnesota Corporation (NSP-Minnesota), is engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas. NSP-Minnesota is subject to regulation by the Federal Energy Regulatory Commission (FERC) and state utility commissions.

The electric production and transmission system of NSP-Minnesota and Northern States Power Co., a Wisconsin corporation (NSP-Wisconsin), (collectively, NSP System) is operated on an integrated basis and managed by NSP-Minnesota and NSP-Wisconsin. The electric production and transmission costs of the NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System. Such costs include current and potential obligations of NSP-Minnesota related to its nuclear generating facilities.

Basis of Accounting — The accompanying financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

- Current maturities of long-term debt are included as long-term debt, while GAAP requires such maturities to be classified as current liabilities.
- Accumulated deferred income taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, in contrast to the GAAP presentation as net current and long-term assets and liabilities.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP presentation, while the FERC requires all regulatory assets and liabilities to be classified as noncurrent deferred debits and credits, respectively.
- Unrecognized tax benefits are recorded for temporary differences in accounts established for accumulated deferred income taxes in the FERC presentation, in contrast to the GAAP presentation as taxes accrued and noncurrent other liabilities.
- Removal costs for future removal obligations are classified as accumulated depreciation within the utility plant accounts in the FERC presentation and as regulatory liabilities in the GAAP presentation.
- For certain capital projects where there is recovery of a return on construction work in progress (CWIP), certain amounts of allowance for funds used during construction (AFUDC) are not recognized in CWIP for GAAP, while for the FERC presentation, they are recorded in CWIP but the benefit is deferred as a liability and amortized over the life of the property as a reduction of costs.
- Certain commodity trading purchases and sales transactions are presented gross as expenses and revenues for the FERC presentation; however the net margin is reported as net sales for the GAAP presentation.
- Various expenses such as donations, lobbying, and other non-regulatory expenses are presented as other income and deductions for the FERC presentation and reported as operating expenses for the GAAP presentation.
- Income tax expense related to utility operations is shown as a component of utility operating expenses in the FERC presentation, in contrast to the GAAP presentation as a below-the-line deduction from operating income.
- Certain utility plant cost disallowances are presented as an extraordinary deduction in the FERC presentation in contrast to the GAAP presentation in which they are included in operating expenses.

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- Wholly-owned subsidiaries are reported using the equity method of accounting in the FERC presentation and are required to be consolidated for GAAP.
- Adjustments to theoretical excess depreciation reserves are recorded as a regulatory asset and an increase to regulatory credits for FERC presentation, in contrast to a reduction to both accumulated depreciation and depreciation expense for GAAP presentation.

If GAAP were followed, these financial statement line items would have values greater/(lesser) than those shown by the FERC presentation of:

(Thousands of Dollars)

Balance Sheet:

Net utility plant	\$	518,576
Current assets		205,244
Current liabilities		150,443
Other long-term assets		(3,065,910)
Long-term debt and other long-term liabilities		(2,492,532)

Statement of Income:

Operating revenues	\$	(13,161)
Operating expenses		(87,747)
Other income and deductions		(10,044)
Interest Charges		(279)

Statement of Cash Flows:

Cash provided by operating activities	\$	(262)
Cash used in investing activities		60
Cash provided by financing activities		—

Use of Estimates — In recording transactions and balances resulting from business operations, NSP-Minnesota uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives or potential disallowances, asset retirement obligations (AROs), certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. The recorded estimates are revised when better information becomes available or when actual amounts can be determined. Those revisions can affect operating results.

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Regulatory Accounting — NSP-Minnesota accounts for certain income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income (OCI), are deferred as regulatory assets based on the expected ability to recover the costs in future rates; and
- Certain credits, which would otherwise be reflected as income or OCI, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If restructuring or other changes in the regulatory environment occur, NSP-Minnesota may no longer be eligible to apply this accounting treatment, and may be required to eliminate regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on NSP-Minnesota's financial condition, results of operations and cash flows. See Note 11 for further discussion of regulatory assets and liabilities.

Revenue Recognition — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is recognized. NSP-Minnesota presents its revenues net of any excise or other fiduciary-type taxes or fees.

NSP-Minnesota participates in Midcontinent Independent System Operator, Inc. (MISO). NSP-Minnesota recognizes sales to both native load and other end use customers on a gross basis. Revenues and charges for energy transacted through RTOs are recorded based upon our evaluation each hour as to whether we are a net seller or a net buyer based upon the total volumes. The real time and day-ahead market are each evaluated separately. If NSP-Minnesota is a net seller the transaction is recorded on a gross basis in electric revenues and cost of sales. If NSP-Minnesota is a net buyer the transaction is recorded on a net basis in cost of sales.

NSP-Minnesota has various rate-adjustment mechanisms in place that provide for the recovery of natural gas, electric fuel and purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred. When applicable, under governing regulatory commission rate orders, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

Certain rate rider mechanisms qualify for alternative revenue recognition under generally accepted accounting principles. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety, or other mandate. When certain criteria are met, revenue is recognized equal to the revenue requirement, including return on rate base items, for the qualified mechanisms. The mechanisms are revised periodically for differences between the total amount collected under the riders and the revenue recognized, which may increase or decrease the level of revenue collected from customers.

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Conservation Programs — NSP-Minnesota has implemented programs in its retail jurisdictions to assist customers in reducing peak demand and conserving energy on the electric and natural gas system. These programs include a wide variety of programs including, but not limited to, commercial process efficiency and lighting upgrades, as well as incentives for participation in air-conditioning interruption.

The costs incurred for conservation improvement programs (CIP) are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Recorded revenues for incentive programs designed for recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the annual period in which they are earned.

NSP-Minnesota's CIP program costs are recovered through a combination of base rate revenue and rider mechanisms. The revenue billed to customers recovers incurred costs for conservation programs and also incentive amounts that are designed to encourage NSP-Minnesota's achievement of energy conservation goals and to compensate for related lost sales margin. NSP-Minnesota recognizes regulatory assets to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Property, Plant and Equipment and Depreciation — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned major maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property. Property, plant and equipment also includes costs associated with property held for future use. The depreciable lives of certain plant assets are reviewed annually and revised, if appropriate. Property, plant and equipment that is required to be decommissioned early by a regulator is reclassified as plant to be retired.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. See Note 8 for a discussion of the loss recognized related to the Monticello life cycle management (LCM)/extended power uprate (EPU) project. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

NSP-Minnesota records depreciation expense related to its plant using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 2.9 and 2.5 percent for the years ended Dec. 31, 2015 and 2014, respectively.

Leases — NSP-Minnesota evaluates a variety of contracts for lease classification at inception, including PPAs and rental arrangements for office space, vehicles, and equipment. Contracts determined to contain a lease because of per unit pricing that is other than fixed or market price, terms regarding the use of a particular asset, and other factors are evaluated further to determine if the arrangement is a capital lease. See Note 9 for further discussion of leases.

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AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in NSP-Minnesota's rate base for establishing utility service rates. In addition to construction-related amounts, cost of capital also is recorded to reflect returns on capital used to finance conservation programs in Minnesota.

Generally AFUDC costs are recovered from customers as the related property is depreciated. However, in some cases, including certain wind and transmission projects, the Minnesota Public Utilities Commission (MPUC) or the FERC have approved a more current recovery of the cost of capital associated with large capital projects, through various riders, resulting in a lower recognition of AFUDC.

AROs — NSP-Minnesota accounts for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the amounts through the establishment of a regulatory asset and recovery in rates. NSP-Minnesota also recovers through rates certain future plant removal costs in addition to AROs. See Note 9 for further discussion of AROs.

Nuclear Decommissioning — Nuclear decommissioning studies estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants and are performed at least every three years and submitted to the MPUC and other state commissions for approval. NSP-Minnesota's most recent triennial nuclear decommissioning studies were approved by the MPUC in October 2015. These studies reflect NSP-Minnesota's plans, under the current operating licenses, for prompt dismantlement of the Monticello and PI facilities. These studies assume that NSP-Minnesota will store spent fuel on site pending removal to a United States government facility.

For rate making purposes, NSP-Minnesota recovers the total decommissioning costs related to its nuclear power plants over each facility's expected service life based on the triennial decommissioning studies filed with the MPUC and other state commissions. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds, and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. See Note 10 for further discussion of the approved nuclear decommissioning studies and funded amounts. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO as described above.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in the nuclear decommissioning fund on the balance sheets. See Note 7 for further discussion of the nuclear decommissioning fund.

Nuclear Fuel Expense — Nuclear fuel expense, which is recorded as NSP-Minnesota's nuclear generating plants use fuel, includes the cost of fuel used in the current period (including AFUDC) and costs associated with the end-of-life fuel segments.

Nuclear Refueling Outage Costs — NSP-Minnesota uses a deferral and amortization method for nuclear refueling operating costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric rates.

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Income Taxes — NSP-Minnesota accounts for income taxes using the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. NSP-Minnesota defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. NSP-Minnesota uses the tax rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. In making such a determination, all available evidence is considered, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax planning strategies and recent financial operations.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes, the reversal of some temporary differences are accounted for as current income tax expense. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize only applies to federal investment tax credits (ITCs). Utility rate regulation also has resulted in the recognition of certain regulatory assets and liabilities related to income taxes, which are summarized in Note 11.

NSP-Minnesota follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. NSP-Minnesota recognizes a tax position in its financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax.

Interest and penalties are recorded separately to their respective line items in the income statement.

Xcel Energy Inc. and its subsidiaries, including NSP-Minnesota, file consolidated federal income tax returns as well as combined or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to Xcel Energy Inc.'s subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with combined state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries which are recorded directly in equity by the subsidiaries based on the relative positive tax liabilities of the subsidiaries.

See Note 5 for further discussion of income taxes.

Types of and Accounting for Derivative Instruments — NSP-Minnesota uses derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price, and commodity trading activities, including forward contracts, futures, swaps and options. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception, as defined by the accounting guidance for derivatives and hedging, are recorded on the balance sheets at fair value as derivative instruments. This includes certain instruments used to mitigate market risk for the utility operations including transmission in organized markets and all instruments related to the commodity trading operations. The classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

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Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues; hedging transactions for vehicle fuel costs are recorded as a component of capital projects or operating costs; and interest rate hedging transactions are recorded as a component of interest expense. NSP-Minnesota is allowed to recover in electric or natural gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility. For further information on derivatives entered to mitigate commodity price risk on behalf of electric and natural gas customers, see Note 7.

Cash Flow Hedges — Certain qualifying hedging relationships are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge). Changes in the fair value of a derivative designated as a cash flow hedge, to the extent effective are included in OCI, or deferred as a regulatory asset or liability based on recovery mechanisms until earnings are affected by the hedged transaction.

Normal Purchases and Normal Sales — NSP-Minnesota enters into contracts for the purchase and sale of commodities for use in its business operations. Derivatives and hedging accounting guidance requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that meet the definition of a derivative may be exempted from derivative accounting if designated as normal purchases or normal sales.

NSP-Minnesota evaluates all of its contracts at inception to determine if they are derivatives and if they meet the normal purchases and normal sales designation requirements. None of the contracts entered into within the commodity trading operations qualify for a normal purchases and normal sales designation.

See Note 7 for further discussion of NSP-Minnesota's risk management and derivative activities.

Commodity Trading Operations — Pursuant to the joint operating agreement approved by the FERC, some of NSP-Minnesota's commodity trading margins are apportioned to Public Service Company of Colorado (PSCo) and Southwestern Public Service Company (SPS). Commodity trading activities are not associated with energy produced from NSP-Minnesota's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms. For further information, see Note 7.

Fair Value Measurements — NSP-Minnesota presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its financial statements. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted net asset values. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used as a primary input to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, NSP-Minnesota may use quoted prices for similar contracts or internally prepared valuation models to determine fair value. For the nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security. For further information, see Note 7.

Cash and Cash Equivalents — NSP-Minnesota considers investments in certain instruments, including commercial paper and money market funds, with a remaining maturity of three months or less at the time of purchase, to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. NSP-Minnesota establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

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Inventory — All inventory is recorded at average cost.

Renewable Energy Credits (RECs) — RECs are marketable environmental instruments that represent proof that energy was generated from eligible renewable energy sources. RECs are awarded upon delivery of the associated energy and can be bought and sold. RECs are typically used as a form of measurement of compliance to renewable portfolio standards (RPS) enacted by those states that are encouraging construction and consumption from renewable energy sources, but can also be sold separately from the energy produced. NSP-Minnesota acquires RECs from the generation or purchase of renewable power.

When RECs are purchased or acquired in the course of generation they are recorded as inventory at cost in Account 158.1. The cost of RECs that are utilized for compliance purposes is recorded as electric fuel and purchased power expense.

Sales of RECs that are purchased or acquired in the course of generation are recorded in electric utility operating revenues on a gross basis. The cost of these RECs, related transaction costs, and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Emission Allowances — Emission allowances, including the annual sulfur dioxide (SO₂) and nitrogen oxide (NO_x) emission allowance entitlement received from the United States Environmental Protection Agency (EPA), are recorded at cost plus associated broker commission fees. NSP-Minnesota follows the inventory accounting model for all emission allowances. Sales of emission allowances are included in electric utility operating revenues and the operating activities section of the statements of cash flows.

Environmental Costs — Environmental costs are recorded when it is probable NSP-Minnesota is liable for remediation costs and the liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs, excluding inflationary increases, are recorded based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating potentially responsible parties (PRPs) exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for NSP-Minnesota's expected share of the cost. Any future costs of restoring sites where operation may be extended are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses, which may include final remediation costs. See Note 9 for further discussion of environmental costs.

Benefit Plans and Other Postretirement Benefits — NSP-Minnesota maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans under applicable accounting guidance requires management to make various assumptions and estimates.

Based on regulatory recovery mechanisms, certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are recorded as regulatory assets and liabilities, rather than OCI.

See Note 6 for further discussion of benefit plans and other postretirement benefits.

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Guarantees — NSP-Minnesota recognizes, upon issuance or modification of a guarantee, a liability for the fair market value of the obligation that has been assumed in issuing the guarantee. This liability includes consideration of specific triggering events and other conditions which may modify the ongoing obligation to perform under the guarantee.

The obligation recognized is reduced over the term of the guarantee as NSP-Minnesota is released from risk under the guarantee. See Note 9 for specific details of issued guarantees.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2015 up to Feb. 22, 2016, the date NSP-Minnesota's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 11, 2016. These financial statements contain all necessary adjustments and disclosures resulting from these evaluations.

2. Investments Accounted for by the Equity Method

In accordance with FERC regulations, NSP-Minnesota's investment in and income from all of its wholly owned subsidiaries are presented using the equity method of accounting. Subsidiaries accounted for under the equity method include:

<u>Name</u>	<u>Geographic Area</u>	<u>Economic Interest</u>
United Power & Land	United States	100%
NSP-Nuclear Corp.	United States	100%
Private Fuel Storage, LLC*	United States	32.8%

* The investment in Private Fuel Storage, LLC has been written down to zero.

Summarized Financial Information of Unconsolidated Investees:

Summarized financial information for all equity-method subsidiaries and projects, including interests owned by NSP-Minnesota was as follows:

(Thousands of Dollars)	2015	2014
Current assets	\$ 1,730	\$ 1,935
Other assets	1,118	1,041
Total assets	<u>\$ 2,848</u>	<u>\$ 2,976</u>
Current liabilities	\$ 277	\$ 325
Other liabilities	18	(14)
Equity	2,553	2,665
Total liabilities and equity	<u>\$ 2,848</u>	<u>\$ 2,976</u>
(Thousands of Dollars)	2015	2014
Operating revenues	\$ 32	\$ 30
Operating loss	(172)	(89)
Net loss	<u>\$ (102)</u>	<u>\$ (57)</u>

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3. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. Money pool borrowings for NSP-Minnesota were as follows:

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2015	Twelve Months Ended Dec. 31, 2014
Borrowing limit	\$ 250	\$ 250
Amount outstanding at period end	—	—
Average amount outstanding	5	12
Maximum amount outstanding	69	150
Weighted average interest rate, computed on a daily basis	0.53%	0.21%
Weighted average interest rate at period end	N/A	N/A

Commercial Paper — NSP-Minnesota meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility. Commercial paper outstanding for NSP-Minnesota was as follows:

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2015	Twelve Months Ended Dec. 31, 2014
Borrowing limit	\$ 500	\$ 500
Amount outstanding at period end	223	142
Average amount outstanding	96	111
Maximum amount outstanding	327	397
Weighted average interest rate, computed on a daily basis	0.43%	0.26%
Weighted average interest rate at end of period	0.72	0.53

Letters of Credit — NSP-Minnesota uses letters of credit, generally with terms of one-year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2015 and 2014, there were \$18 million and \$24 million of letters of credit outstanding, respectively, under the credit facility. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facility — In order to use its commercial paper program to fulfill short-term funding needs, NSP-Minnesota must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper in an amount exceeding available capacity under this credit facility. The line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Credit Agreement — NSP-Minnesota has a five-year credit agreement with a syndicate of banks. The total size of the credit facility is \$500 million and the credit facility matures in October 2019.

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NSP-Minnesota has the right to request an extension of the termination date for two additional one-year periods. All extension requests are subject to majority bank group approval.

Other features of NSP-Minnesota's credit facility include:

- NSP-Minnesota may increase its credit facility by up to \$100 million.
- The credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65 percent. NSP-Minnesota was in compliance as its debt-to-total capitalization ratio was 48 percent at both Dec. 31, 2015 and 2014. If NSP-Minnesota does not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender.
- The credit facility has a cross-default provision that provides NSP-Minnesota will be in default on its borrowings under the facility if NSP-Minnesota or any of its subsidiaries whose total assets exceed 15 percent of NSP-Minnesota's consolidated total assets, default on certain indebtedness in an aggregate principal amount exceeding \$75 million.
- NSP-Minnesota was in compliance with all financial covenants on its debt agreements as of Dec. 31, 2015 and 2014.
- The interest rates under the line of credit are based on Eurodollar borrowing margins ranging from 87.5 to 175 basis points per year based on the applicable long-term credit ratings.
- The commitment fees, also based on applicable long-term credit ratings, are calculated on the unused portion of the lines of credit at a range of 7.5 to 27.5 basis points per year.

At Dec. 31, 2015, NSP-Minnesota had the following committed credit facility available (in millions):

Credit Facility (a)	Drawn (b)	Available
\$ 500	\$ 241	\$ 259

(a) This credit facility matures in October 2019.

(b) Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. NSP-Minnesota had no direct advances on the credit facility outstanding at Dec. 31, 2015 and 2014.

Long-Term Borrowings and Other Financing Instruments

Generally, all real and personal property of NSP-Minnesota is subject to the lien of its first mortgage indenture. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses associated with refinanced debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines.

In 2015, NSP-Minnesota issued \$300 million of 2.2 percent first mortgage bonds due Aug. 15, 2020 and \$300 million of 4.0 percent first mortgage bonds due Aug. 15, 2045. In 2014, NSP-Minnesota issued \$300 million of 4.125 percent first mortgage bonds due May 15, 2044.

During the next five years, NSP-Minnesota has long-term debt maturities of \$500 million and \$300 million due in 2018 and 2020, respectively.

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Deferred Financing Costs — Deferred debits include deferred financing costs of approximately \$37.7 million and \$33.6 million, net of amortization, at Dec. 31, 2015 and 2014, respectively. NSP-Minnesota is amortizing these financing costs over the remaining maturity periods of the related debt.

Dividend and Other Capital-Restrictions — NSP-Minnesota's dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only.

NSP-Minnesota's first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy Inc., the holder of its common stock. Even with this restriction, NSP-Minnesota could have paid more than \$1.7 billion and \$1.6 billion in additional cash dividends on common stock at Dec. 31, 2015 and 2014, respectively.

The most restrictive dividend limitation for NSP-Minnesota is imposed by its state regulatory commissions. NSP-Minnesota's state regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay to Xcel Energy Inc. by requiring an equity-to-total capitalization ratio between 46.9 percent and 57.3 percent. NSP-Minnesota's equity-to-total capitalization ratio was 52.1 percent at Dec. 31, 2015 and \$967 million in retained earnings was not restricted. Total capitalization for NSP-Minnesota was \$9.9 billion at Dec. 31, 2015, which did not exceed the limits imposed by the commissions of \$10.5 billion.

4. Joint Ownership of Generation and Transmission Facilities

Following are the investments by NSP-Minnesota in jointly owned generation and transmission facilities and the related ownership percentages as of Dec. 31, 2015:

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation (a)	CWIP	Ownership %
Electric Generation:				
Sherco Unit 3	\$ 590,048	\$ 386,675	\$ 4,984	59%
Sherco Common Facilities Units 1, 2 and 3	145,825	93,583	47	80
Sherco Substation	4,790	3,054	—	59
Electric Transmission:				
Grand Meadow Line and Substation	9,248	1,451	—	50
CapX2020	947,674	107,985	68,834	51
Total	\$ 1,697,585	\$ 592,748	\$ 73,865	

(a) Asset retirement obligation is not included.

NSP-Minnesota has approximately 517 megawatts (MW) of jointly owned generating capacity. NSP-Minnesota's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for providing its own financing.

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5. Income Taxes

Consolidated Appropriations Act, 2016 - In December 2015, the Consolidated Appropriations Act, 2016 (Act) was signed into law. The Act provides for the following:

- Immediate expensing, or “bonus depreciation,” of 50 percent for property placed in service in 2015, 2016, and 2017; 40 percent for property placed in service in 2018; and 30 percent for property placed in service in 2019. Additionally, some longer production period property placed in service in 2020 will be eligible for bonus depreciation;
- Production tax credits (PTCs) at 100 percent of the credit rate (\$0.023 per kilowatt hours (KWh)) for wind energy projects that begin construction by the end of 2016; 80 percent of the credit rate for projects that begin construction in 2017; 60 percent of the credit rate for projects that begin construction in 2018; and 40 percent of the credit rate for projects that begin construction in 2019. The wind energy PTC was not extended for projects that begin construction after 2019;
- ITCs at 30 percent for commercial solar projects that begin construction by the end of 2019; 26 percent for projects that begin construction in 2020; 22 percent for projects that begin construction in 2021; and 10 percent for projects thereafter;
- Research and experimentation (R&E) credit was permanently extended; and
- Delay of two years (until 2020) of the excise tax on certain employer-provided health insurance plans.

The accounting related to the Act was recorded beginning in the fourth quarter of 2015 because a change in tax law is accounted for beginning in the period of enactment.

Tax Increase Prevention Act of 2014 — In 2014, the Tax Increase Prevention Act (TIPA) was signed into law. The TIPA provides for the following:

- The R&E credit was extended for 2014;
- PTCs were extended for projects that began construction before the end of 2014 with certain projects qualifying into future years; and
- 50 percent bonus depreciation was extended one year through 2014. Additionally, some longer production period property placed in service in 2015 is also eligible for 50 percent bonus depreciation.

The accounting related to the TIPA was recorded beginning in the fourth quarter of 2014 because a change in tax law is accounted for in the period of enactment.

Federal Tax Loss Carryback Claims — In 2012, 2013, 2014 and 2015, NSP-Minnesota identified certain expenses related to 2009, 2010, 2011, 2013, 2014 and 2015 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, NSP-Minnesota recognized a tax benefit of approximately \$5 million in 2015, \$17 million in 2014, \$12 million in 2013 and \$15 million in 2012.

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Federal Audit — NSP-Minnesota is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. In the third quarter of 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. As of Dec. 31, 2015, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in \$14 million of income tax expense for the 2009 through 2011 and 2013 claims, the recently filed 2014 claim, and the anticipated claim for 2015. In the fourth quarter of 2015, the IRS forwarded the issue to the Office of Appeals (Appeals); however, the outcome and timing of a resolution is uncertain. The statute of limitations applicable to Xcel Energy's 2009 through 2011 federal income tax returns expires in December 2016 following an extension to allow additional time for the Appeals process. In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. As of Dec. 31, 2015, the IRS had not proposed any material adjustments to tax years 2012 and 2013.

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2015, NSP-Minnesota's earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2009. There are currently no state income tax audits in progress.

Unrecognized Tax Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual effective tax rate (ETR). In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment of cash to the taxing authority to an earlier period.

A reconciliation of the amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Unrecognized tax benefit — Permanent tax positions	\$ 20.1	\$ 12.2
Unrecognized tax benefit — Temporary tax positions	35.3	18.2
Total unrecognized tax benefit	\$ 55.4	\$ 30.4

A reconciliation of the beginning and ending amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	2015	2014
Balance at Jan. 1	\$ 30.4	\$ 25.2
Additions based on tax positions related to the current year	14.0	10.3
Reductions based on tax positions related to the current year	(2.1)	(1.2)
Additions for tax positions of prior years	14.0	8.9
Reductions for tax positions of prior years	(0.9)	(4.2)
Settlements with taxing authorities	—	(8.6)
Balance at Dec. 31	\$ 55.4	\$ 30.4

The unrecognized tax benefit amounts were reduced by the tax benefits associated with net operating losses (NOLs) and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	Dec. 31, 2015	Dec. 31, 2014
NOL and tax credit carryforwards	\$ (15.2)	\$ (10.8)

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It is reasonably possible that NSP-Minnesota's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals and audit progress and state audits resume. As the IRS Appeals and audit progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately \$32 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at Dec. 31, 2015 and 2014 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2015 or 2014.

Uncertainty in Income Taxes — The FERC has not fully adopted the accounting guidance for uncertainty in income taxes. Accordingly, NSP-Minnesota has recorded its unrecognized tax benefits for temporary adjustments, including NOL and tax credit carryforwards, in accounts established for accumulated deferred income taxes.

Other Income Tax Matters — NOL amounts represent the amount of the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2015	2014
Federal NOL carryforward	1,055.0	597.5
Federal tax credit carryforwards	170.8	139.9
State NOL carryforward	277.2	44.6
State tax credit carryforwards, net of federal detriment	32.0	3.1
Valuation allowances for state credit carryforwards, net of federal detriment	(24.9)	-

The federal carryforward periods expire between 2021 and 2035. The state carryforward periods expire between 2020 and 2035.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The following reconciles such differences for the years ending Dec. 31:

	2015	2014
Federal statutory rate	35.0%	35.0%
Increases (decreases) in tax from:		
Tax credits recognized, net of federal income tax expense	(6.3)	(5.3)
State income taxes, net of federal income tax benefit	5.9	5.8
Regulatory differences - utility plant items	(1.7)	(0.2)
Net operating loss carryback	(0.9)	(2.3)
Other, net	1.6	(0.1)
Effective income tax rate	33.6%	32.9%

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The components of income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2015	2014
Current federal tax (benefit) expense	\$ (41,023)	\$ 12
Current state tax (benefit) expense	(3,926)	25,352
Current change in unrecognized tax expense	7,875	3,748
Deferred federal tax expense	167,532	143,189
Deferred state tax expense	52,077	27,552
Deferred investment tax credits	(1,729)	(1,735)
Total income tax expense	<u>\$ 180,806</u>	<u>\$ 198,118</u>

The components of deferred income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2015	2014
Deferred tax expense excluding items below	\$218,035	\$187,814
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	1,401	(16,417)
Tax (expense) benefit allocated to other comprehensive income and other	173	(656)
Deferred tax expense	<u>\$219,609</u>	<u>\$170,741</u>

The components of accumulated deferred income taxes at Dec. 31 were as follows:

(Thousands of dollars)	2015	2014
Deferred tax liabilities:		
Differences between book and tax bases of property	\$3,330,774	\$2,940,980
Regulatory assets	156,499	135,064
Employee Benefits	76,043	67,449
Other	21,202	35,059
Total deferred tax liabilities	<u>\$3,584,518</u>	<u>\$3,178,552</u>
Deferred tax assets:		
Differences between book and tax bases of property	\$295,335	\$302,208
NOL carryforward	391,447	217,160
Tax credit carryforward	177,851	142,924
Employee benefits	59,411	60,383
Rate refund	26,298	30,785
Regulatory liabilities	10,188	17,099
Deferred investment tax credits	11,419	12,200
Other	28,671	29,930
Total deferred tax assets	<u>\$1,000,620</u>	<u>\$812,689</u>
Net deferred tax liability	<u>\$2,583,898</u>	<u>\$2,365,863</u>

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6. Benefit Plans and Other Postretirement Benefits

Consistent with the process for rate recovery of pension and postretirement benefits for its employees, NSP-Minnesota accounts for its participation in, and related costs of, pension and other postretirement benefit plans sponsored by Xcel Energy Inc. as multiple employer plans. NSP-Minnesota is responsible for its share of cash contributions, plan costs and obligations and is entitled to its share of plan assets; accordingly, NSP-Minnesota accounts for its pro rata share of these plans, including pension expense and contributions, resulting in accounting consistent with that of a single employer plan exclusively for NSP-Minnesota employees.

Xcel Energy, which includes NSP-Minnesota, offers various benefit plans to its employees. Approximately 62 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2015, NSP-Minnesota had 1,983 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2016. NSP-Minnesota also had an additional 265 nuclear operation bargaining employees covered under several collective-bargaining agreements. Some of these agreements expired in 2015, but were extended to 2016. The remaining agreements expire in 2016 and 2018.

The plans invest in various instruments which are disclosed under the accounting guidance for fair value measurements which establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring fair value. The three levels in the hierarchy and examples of each level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets as of the reporting date. The types of assets included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets included in Level 3 are those with inputs requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

Insurance contracts — Insurance contract fair values take into consideration the value of the investments in separate accounts of the insurer, which are priced based on observable inputs.

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Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. Preferred stock is valued using recent trades and quoted prices of similar securities. The fair values for commingled funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per share market value. The investments in commingled funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on the plan's evaluation of its ability to redeem private equity and real estate investments, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Derivative Instruments — Fair values for foreign currency derivatives are determined using pricing models based on the prevailing forward exchange rate of the underlying currencies. The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Pension Benefits

Xcel Energy, which includes NSP-Minnesota, has several noncontributory, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service, the employee's average pay and, in some cases, social security benefits. Xcel Energy Inc.'s and NSP-Minnesota's policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement plan (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides unfunded, nonqualified benefits for compensation that is in excess of the limits applicable to the qualified pension plans. The total obligations of the SERP and nonqualified plan as of Dec. 31, 2015 and 2014 were \$41.8 million and \$46.5 million, respectively, of which \$5.1 million and \$5.7 million was attributable to NSP-Minnesota. In 2015 and 2014, Xcel Energy recognized net benefit cost for financial reporting for the SERP and nonqualified plans of \$9.5 million and \$4.7 million, respectively, of which \$0.6 million and \$0.5 million was attributable to NSP-Minnesota. Benefits for these unfunded plans are paid out of Xcel Energy's operating cash flows.

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Xcel Energy Inc. and NSP-Minnesota base the investment-return assumption on expected long-term performance for each of the investment types included in the pension asset portfolio and consider the historical returns achieved by the asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. Xcel Energy Inc. and NSP-Minnesota continually review pension assumptions. The pension cost determination assumes a forecasted mix of investment types over the long term.

- Investment returns in 2015 and 2014 were below the assumed level of 7.25 percent for all years; and
- In 2016, NSP-Minnesota's expected investment-return assumption is 7.10 percent.

The assets are invested in a portfolio according to Xcel Energy Inc.'s and NSP-Minnesota's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by pension assets in any year.

The following table presents the target pension asset allocations for NSP-Minnesota at Dec. 31 for the upcoming year:

	2015	2014
Domestic and international equity securities	41%	39%
Long-duration fixed income and interest rate swap securities	23	23
Short-to-intermediate fixed income securities	14	14
Alternative investments	20	22
Cash	2	2
Total	100%	100%

The ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios. The aggregate projected asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

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Pension Plan Assets

The following tables present, for each of the fair value hierarchy levels, NSP-Minnesota's pension plan assets that are measured at fair value as of Dec. 31, 2015 and 2014:

(Thousands of Dollars)	Dec. 31, 2015			
	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ 40,273	\$ —	\$ —	\$ 40,273
Derivatives	—	596	—	596
Government securities	—	87,510	—	87,510
Corporate bonds	—	70,114	—	70,114
Asset-backed securities	—	680	—	680
Common stock	28,257	—	—	28,257
Private equity investments	—	—	40,023	40,023
Commingled funds	—	515,215	—	515,215
Real estate	—	—	16,182	16,182
Other	—	1,393	—	1,393
Total	\$ 68,530	\$ 675,508	\$ 56,205	\$ 800,243

(Thousands of Dollars)	Dec. 31, 2014			
	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ 52,506	\$ —	\$ —	\$ 52,506
Derivatives	—	185	—	185
Government securities	—	106,763	—	106,763
Corporate bonds	—	87,821	—	87,821
Asset-backed securities	—	1,073	—	1,073
Mortgage-backed securities	—	3,152	—	3,152
Common stock	29,368	—	—	29,368
Private equity investments	—	—	46,982	46,982
Commingled funds	—	543,008	—	543,008
Real estate	—	—	16,660	16,660
Securities lending collateral obligation and other	—	(6,603)	—	(6,603)
Total	\$ 81,874	\$ 735,399	\$ 63,642	\$ 880,915

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The following tables present the changes in NSP-Minnesota's Level 3 pension plan assets for the years ended Dec. 31, 2015 and 2014:

(Thousands of Dollars)	Jan. 1, 2015	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers out of Level 3	Dec. 31, 2015
Private equity investments	\$ 46,982	\$ 8,896	\$ (11,827)	\$ (4,028)	\$ —	\$ 40,023
Real estate	16,660	2,243	(3,556)	835	—	16,182
Total	<u>\$ 63,642</u>	<u>\$ 11,139</u>	<u>\$ (15,383)</u>	<u>\$ (3,193)</u>	<u>\$ —</u>	<u>\$ 56,205</u>

(Thousands of Dollars)	Jan. 1, 2014	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances and Settlements, Net	Transfers out of Level 3	Dec. 31, 2014
Private equity investments	48,633	7,949	(6,785)	(2,815)	—	46,982
Real estate	14,904	1,104	(1,197)	1,849	—	16,660
Total	<u>\$ 63,537</u>	<u>\$ 9,053</u>	<u>\$ (7,982)</u>	<u>\$ (966)</u>	<u>\$ —</u>	<u>\$ 63,642</u>

Benefit Obligations — A comparison of the actuarially computed pension benefit obligation and plan assets for NSP-Minnesota is presented in the following table:

(Thousands of Dollars)	2015	2014
Accumulated Benefit Obligation at Dec. 31	\$ 954,610	\$ 1,027,467
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	\$ 1,099,671	\$ 1,062,633
Service cost	31,556	29,699
Interest cost	43,214	47,309
Actuarial (gain) loss	(60,091)	74,204
Benefit payments	(91,227)	(114,174)
Obligation at Dec. 31	<u>\$ 1,023,123</u>	<u>\$ 1,099,671</u>

(Thousands of Dollars)	2015	2014
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	\$ 880,915	\$ 887,642
Actual (loss) return on plan assets	(22,180)	55,332
Employer contributions	32,735	52,115
Benefit payments	(91,227)	(114,174)
Fair value of plan assets at Dec. 31	<u>\$ 800,243</u>	<u>\$ 880,915</u>

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(Thousands of Dollars)	2015	2014
Funded Status of Plans at Dec. 31:		
Funded status (a)	\$ (222,880)	\$ (218,756)

(a) Amounts are recognized in noncurrent liabilities on NSP-Minnesota's balance sheet.

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	\$ 589,796	\$ 611,069
Prior service cost	4,710	5,646
Total	\$ 594,506	\$ 616,715

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Other Regulatory Assets	\$ 594,506	\$ 616,715
Measurement date	Dec. 31, 2015	Dec. 31, 2014

	2015	2014
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.66%	4.11%
Expected average long-term increase in compensation level	4.00%	3.75%
Mortality table	RP 2014	RP 2014

Mortality — In 2014, the Society of Actuaries published a new mortality table and projection scale that increased the overall life expectancy of males and females. NSP-Minnesota has reviewed its own population through a credibility analysis and adopted the RP 2014 table, with modifications, based on its population and specific experience. During 2015, a new projection table was released (MP 2015). NSP-Minnesota evaluated the updated projection table and concluded that the methodology adopted at Dec. 31, 2014 is consistent with the recently updated table and continues to be representative of its population.

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2014 through 2016 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- \$125.0 million in January 2016, of which \$49.4 million was attributable to NSP-Minnesota;
- \$90.1 million in 2015, of which \$32.7 million was attributable to NSP-Minnesota;
- \$130.6 million in 2014, of which \$52.1 million was attributable to NSP-Minnesota.

For future years, Xcel Energy and NSP-Minnesota anticipate contributions will be made as necessary.

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Plan Amendments — In 2015 and 2014 there were no plan amendments made which affected the projected benefit obligation.

Benefit Costs — The components of NSP-Minnesota's net periodic pension cost were:

(Thousands of Dollars)	2015	2014
Service cost	\$ 31,556	\$ 29,699
Interest cost	43,214	47,309
Expected return on plan assets	(62,830)	(62,920)
Amortization of prior service cost	936	936
Amortization of net loss	46,192	44,785
Net periodic pension cost	59,068	59,809
Costs not recognized due to effects of regulation	(30,766)	(29,485)
Net benefit cost recognized for financial reporting	\$ 28,302	\$ 30,324
	2015	2014

Significant Assumptions Used to Measure Costs:

Discount rate	4.11%	4.75%
Expected average long-term increase in compensation level	3.75	3.75
Expected average long-term rate of return on assets	7.25	7.25

In addition to the benefit costs in the table above, for the pension plans sponsored by Xcel Energy, Inc., costs are allocated to NSP-Minnesota based on Xcel Energy Services Inc. employees' labor costs. Amounts allocated to NSP-Minnesota were \$11.0 million and \$10.3 million in 2015 and 2014, respectively. Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2016 pension cost calculations is 7.10 percent. The cost calculation uses a market-related valuation of pension assets. Xcel Energy, including NSP-Minnesota, uses a calculated value method to determine the market-related value of the plan assets. The market-related value begins with the fair market value of assets as of the beginning of the year. The market-related value is determined by adjusting the fair market value of assets to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year. As these differences between actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized over the expected average remaining years of service for active employees.

Defined Contribution Plans

Xcel Energy, which includes NSP-Minnesota, maintains 401(k) and other defined contribution plans that cover substantially all employees. The expense to these plans for NSP-Minnesota was approximately \$11.2 million in 2015 and \$11.1 million in 2014.

Postretirement Health Care Benefits

Xcel Energy, which includes NSP-Minnesota, has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees. NSP-Minnesota discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees who retired after 1999.

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Regulatory agencies for nearly all retail and wholesale utility customers have allowed rate recovery of accrued postretirement benefit costs.

Plan Assets — Certain state agencies that regulate Xcel Energy Inc.'s utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. These assets are invested in a manner consistent with the investment strategy for the pension plan.

The following table presents the target postretirement asset allocations for Xcel Energy Inc. and NSP-Minnesota at Dec. 31 for the upcoming year:

	2015	2014
Domestic and international equity securities	25%	25%
Short-to-intermediate fixed income securities	57	57
Alternative investments	13	13
Cash	5	5
Total	100%	100%

Xcel Energy Inc. and NSP-Minnesota base investment-return assumptions for the postretirement health care fund assets on expected long-term performance for each of the investment types included in the asset portfolio. Assumptions and target allocations are determined at the master trust level. The investment mix at each of Xcel Energy Inc.'s utility subsidiaries may vary from the investment mix of the total asset portfolio. The assets are invested in a portfolio according to Xcel Energy Inc.'s and NSP-Minnesota's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected allocation of assets to selected asset classes, given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility is not considered to be a material factor in postretirement health care costs.

The following tables present, for each of the fair value hierarchy levels, NSP-Minnesota's proportionate allocation of the total postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2015 and 2014:

(Thousands of Dollars)	Dec. 31, 2015			
	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ 130	\$ —	\$ —	\$ 130
Government securities	—	260	—	260
Insurance contracts	—	313	—	313
Corporate bonds	—	483	—	483
Asset-backed securities	—	190	—	190
Mortgage-backed securities	—	236	—	236
Commingled funds	—	1,358	—	1,358
Other	—	(1)	—	(1)
Total	\$ 130	\$ 2,839	\$ —	\$ 2,969

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(Thousands of Dollars)	Dec. 31, 2014			
	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ 115	\$ —	\$ —	\$ 115
Derivatives	—	1	—	1
Government securities	—	213	—	213
Insurance contracts	—	221	—	221
Corporate bonds	—	237	—	237
Asset-backed securities	—	16	—	16
Mortgage-backed securities	—	49	—	49
Commingled funds	—	1,237	—	1,237
Other	—	(8)	—	(8)
Total	\$ 115	\$ 1,966	\$ —	\$ 2,081

For the years ended Dec. 31, 2015 and 2014 there were no assets transferred in or out of Level 3.

Benefit Obligations — A comparison of the actuarially computed benefit obligation and plan assets for NSP-Minnesota is presented in the following table:

(Thousands of Dollars)	2015	2014
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	\$ 97,946	\$ 108,232
Service cost	159	187
Interest cost	3,814	4,993
Medicare subsidy reimbursements	59	12
Plan participants' contributions	552	995
Actuarial gain	(5,197)	(5,742)
Benefit payments	(8,649)	(10,731)
Obligation at Dec. 31	\$ 88,684	\$ 97,946

(Thousands of Dollars)	2015	2014
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	\$ 2,081	\$ 4,299
Actual return on plan assets	8	3
Plan participants' contributions	552	995
Employer contributions	8,977	7,515
Benefit payments	(8,649)	(10,731)
Fair value of plan assets at Dec. 31	\$ 2,969	\$ 2,081

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(Thousands of Dollars)	2015	2014
Funded Status of Plans at Dec. 31:		
Funded status	\$ (85,715)	\$ (95,865)
Other noncurrent liabilities	(85,715)	(95,865)
Net postretirement amounts recognized on balance sheets	\$ (85,715)	\$ (95,865)

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	\$ 40,864	\$ 48,040
Prior service credit	(21,469)	(24,505)
Total	\$ 19,395	\$ 23,535

(Thousands of Dollars)	2015	2014
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Other regulatory assets	\$ 18,133	\$ 22,004
Deferred income taxes	515	625
Net-of-tax accumulated OCI	747	906
Total	\$ 19,395	\$ 23,535

Measurement date	Dec. 31, 2015	Dec. 31, 2014

	2015	2014
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	4.65%	4.08%
Mortality table	RP 2014	RP 2014
Health care costs trend rate — initial	6.00%	6.50%

Effective Jan. 1, 2016, the initial medical trend rate was decreased from 6.5 percent to 6.0 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is three years. Xcel Energy Inc. and NSP-Minnesota base the medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by the retiree medical plan.

A one-percent change in the assumed health care cost trend rate would have the following effects on NSP-Minnesota:

(Thousands of Dollars)	One Percentage Point	
	Increase	Decrease
Accumulated postretirement benefit obligation	\$ 8,558	\$ (7,282)
Service and interest components	451	(376)

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Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy, which includes NSP-Minnesota, contributed \$18.3 million and \$17.1 million during 2015 and 2014, respectively, of which \$9.0 million and \$7.5 million were attributable to NSP-Minnesota. Xcel Energy expects to contribute approximately \$12.3 million during 2016, of which \$8.6 million is attributable to NSP-Minnesota.

Plan Amendments — In 2015 and 2014, there were no plan amendments made which affected the benefit obligation.

Benefit Costs — The components of NSP-Minnesota's net periodic postretirement benefit costs were:

(Thousands of Dollars)	2015	2014
Service cost	\$ 159	\$ 187
Interest cost	3,814	4,993
Expected return on plan assets	(121)	(301)
Amortization of transition obligation	—	—
Amortization of prior service credit	(3,036)	(3,036)
Amortization of net loss	2,092	3,416
Net periodic postretirement benefit cost	\$ 2,908	\$ 5,259
	2015	2014

Significant Assumptions Used to Measure Costs:

Discount rate	4.08%	4.82%
Expected average long-term rate of return on assets	5.80	7.00

In addition to the benefit costs in the table above, for the postretirement health care plans sponsored by Xcel Energy, Inc., costs are allocated to NSP-Minnesota based on Xcel Energy Services Inc. employees' labor costs.

Projected Benefit Payments

The following table lists NSP-Minnesota's projected benefit payments for the pension and postretirement benefit plans:

(Thousands of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2016	\$ 87,981	\$ 8,586	\$ 12	\$ 8,574
2017	89,225	8,118	11	8,107
2018	89,188	7,860	11	7,849
2019	90,255	7,522	11	7,511
2020	90,104	7,307	14	7,293
2021-2025	417,009	31,313	67	31,246

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Multiemployer Plans

NSP-Minnesota contributes to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees, including electrical workers, boilermakers, and other construction and facilities workers who may perform services for more than one employer during a given period and do not participate in the NSP-Minnesota sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

Contributions to multiemployer plans were as follows for the years ended Dec. 31, 2015 and 2014. The average number of NSP-Minnesota union employees covered by the multiemployer pension plans decreased to approximately 850 in 2015 from approximately 1,000 in 2014. There were no other significant changes to the nature or magnitude of the participation of NSP-Minnesota in multiemployer plans for the years presented:

(Thousands of Dollars)	2015	2014
Multiemployer plan contributions:		
Pension	\$ 17,223	\$ 20,254
Other postretirement benefits	135	273
Total	\$ 17,358	\$ 20,527

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

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Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, international equity funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds and international equity funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on NSP-Minnesota's evaluation of its ability to redeem private equity and real estate investments, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2. When contractual settlements extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota include transmission congestion instruments, generally referred to as FTRs, purchased from MISO, PJM Interconnection, LLC (PJM), Electric Reliability Council of Texas and New York Independent System Operator (NYISO). Financial transmission rights (FTRs) purchased from a regional transmission organization (RTO) are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of energy congestion, which is caused by overall transmission load and other transmission constraints. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR. NSP-Minnesota's valuation process for FTRs utilizes complex iterative modeling to predict the impacts of forecasted changes in these drivers of transmission system congestion on the historical pricing of FTR purchases.

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If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of management's forecasts for several of the inputs to this complex valuation model – including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of NSP-Minnesota's FTRs relative to its electric utility operations, the numerous unobservable quantitative inputs to the complex model used for valuation of FTRs are insignificant to the financial statements of NSP-Minnesota.

Non-Derivative Instruments Fair Value Measurements

The Nuclear Regulatory Commission (NRC) requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and PI nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins. NSP-Minnesota uses the MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the nuclear decommissioning fund were \$328.8 million and \$312.1 million at Dec. 31, 2015 and 2014, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were \$100.2 million and \$74.1 million at Dec. 31, 2015 and 2014, respectively.

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The following tables present the cost and fair value of NSP-Minnesota's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund at Dec. 31, 2015 and 2014:

	Dec. 31, 2015				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund (a)					
Cash equivalents	\$ 27,484	\$ 27,484	\$ —	\$ —	\$ 27,484
Commingled funds	392,838	—	410,634	—	410,634
International equity funds	259,114	—	231,122	—	231,122
Private equity investments	105,965	—	—	157,528	157,528
Real estate	61,816	—	—	84,750	84,750
Debt securities:					
Government securities	24,444	—	21,356	—	21,356
U.S. corporate bonds	73,061	—	65,276	—	65,276
International corporate bonds	13,726	—	12,801	—	12,801
Municipal bonds	49,255	—	51,589	—	51,589
Asset-backed securities	2,837	—	2,830	—	2,830
Mortgage-backed securities	11,444	—	11,621	—	11,621
Equity securities:					
Common stock	473,615	647,159	—	—	647,159
Total	\$ 1,495,599	\$ 674,643	\$ 807,229	\$ 242,278	\$ 1,724,150

(a) Reported in nuclear decommissioning fund and other investments on the balance sheet, which also includes \$34.1 million of miscellaneous investments.

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	Dec. 31, 2014				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund (a)					
Cash equivalents	\$ 24,184	\$ 24,184	\$ —	\$ —	\$ 24,184
Commingled funds	470,013	—	465,615	—	465,615
International equity funds	80,454	—	78,721	—	78,721
Private equity investments	73,936	—	—	101,237	101,237
Real estate	43,859	—	—	64,249	64,249
Debt securities:					
Government securities	30,674	—	28,808	—	28,808
U.S. corporate bonds	81,463	—	77,562	—	77,562
International corporate bonds	16,950	—	16,341	—	16,341
Municipal bonds	242,282	—	249,201	—	249,201
Asset-backed securities	9,131	—	9,250	—	9,250
Mortgage-backed securities	23,225	—	23,895	—	23,895
Equity securities:					
Common stock	369,751	564,858	—	—	564,858
Total	\$ 1,465,922	\$ 589,042	\$ 949,393	\$ 165,486	\$ 1,703,921

(a) Reported in nuclear decommissioning fund and other investments on the balance sheet, which also includes \$31.4 million of miscellaneous investments.

The following tables present the changes in Level 3 nuclear decommissioning fund investments:

(Thousands of Dollars)	Jan. 1, 2015	Purchases	Settlements	Gains	Transfers out of Level 3	Dec. 31, 2015
				Recognized as Regulatory Assets ^(a)		
Private equity investments	\$ 101,237	\$ 32,029	\$ —	\$ 24,262	\$ —	\$ 157,528
Real estate	64,249	27,568	(9,611)	2,544	—	84,750
Total	\$ 165,486	\$ 59,597	\$ (9,611)	\$ 26,806	\$ —	\$ 242,278

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(Thousands of Dollars)	Jan. 1, 2014	Purchases	Settlements	Gains Recognized as Regulatory Assets ^(a)	Transfers out of Level 3	Dec. 31, 2014
Private equity investments	62,696	22,078	(286)	16,749	—	101,237
Real estate	57,368	8,088	(9,794)	8,587	—	64,249
Total	<u>\$ 120,064</u>	<u>\$ 30,166</u>	<u>\$ (10,080)</u>	<u>\$ 25,336</u>	<u>\$ —</u>	<u>\$ 165,486</u>

(a) Gains and losses are deferred as a component of the regulatory asset for nuclear decommissioning.

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at Dec. 31, 2015:

(Thousands of Dollars)	Final Contractual Maturity					Total
	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years		
Government securities	\$ —	\$ —	\$ —	\$ 21,356		\$ 21,356
U.S. corporate bonds	—	16,005	51,384	(2,113)		65,276
International corporate bonds	—	2,787	9,382	632		12,801
Municipal bonds	153	264	17,814	33,358		51,589
Asset-backed securities	—	—	2,830	—		2,830
Mortgage-backed securities	—	—	—	11,621		11,621
Debt securities	<u>\$ 153</u>	<u>\$ 19,056</u>	<u>\$ 81,410</u>	<u>\$ 64,854</u>		<u>\$ 165,473</u>

Derivative Instruments Fair Value Measurements

NSP-Minnesota enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — NSP-Minnesota enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

At Dec. 31, 2015, accumulated other comprehensive losses related to interest rate derivatives included \$0.8 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for unsettled hedges, as applicable.

Wholesale and Commodity Trading Risk — NSP-Minnesota conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments. NSP-Minnesota's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

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Commodity Derivatives — NSP-Minnesota enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel, and weather derivatives.

At Dec. 31, 2015, NSP-Minnesota had various vehicle fuel contracts designated as cash flow hedges extending through December 2016. NSP-Minnesota also enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in OCI or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. NSP-Minnesota recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the years ended Dec. 31, 2015 and 2014.

At Dec. 31, 2015, net losses related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included \$0.1 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, NSP-Minnesota enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenue, net of amounts credited to customers under margin-sharing mechanisms.

The following table details the gross notional amounts of commodity forwards, options and FTRs at Dec. 31:

(Amounts in Thousands) (a)(b)	2015	2014
Megawatt hours (MWh) of electricity	43,611	49,431
Million British thermal units (MMBtu) of natural gas	7,971	173
Gallons of vehicle fuel	77	155

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — NSP-Minnesota continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of NSP-Minnesota's own credit risk when determining the fair value of derivative liabilities, the impact of considering credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the balance sheets.

NSP-Minnesota employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

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NSP-Minnesota's most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities. At Dec. 31, 2015, six of NSP-Minnesota's 10 most significant counterparties for these activities, comprising \$23.1 million or 35 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's Ratings Services, Moody's Investor Services or Fitch Ratings. Three of the 10 most significant counterparties, comprising \$8.0 million or 12 percent of this credit exposure at Dec. 31, 2015, were not rated by these external agencies, but based on NSP-Minnesota's internal analysis, had credit quality consistent with investment grade. Another of these significant counterparties, comprising \$6.3 million or 10 percent of this credit exposure, had credit quality less than investment grade, based on ratings from external and internal analysis. All 10 of these significant counterparties are municipal or cooperative electric entities, or other utilities.

Financial Impact of Qualifying Cash Flow Hedges — The impact of qualifying interest rate and vehicle fuel cash flow hedges on NSP-Minnesota's accumulated other comprehensive loss, included in the statements of common stockholder's equity and in the statements of comprehensive income, is detailed in the following table:

(Thousands of Dollars)	2015	2014
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	\$ (19,909)	\$ (20,609)
After-tax net unrealized (losses) gains related to derivatives accounted for as hedges	(39)	(89)
After-tax net realized losses on derivative transactions reclassified into earnings	858	789
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	\$ (19,090)	\$ (19,909)

The following tables detail the impact of derivative activity during the years ended Dec. 31, 2015 and 2014 on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Year Ended Dec. 31, 2015					
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income	
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)		
(Thousands of Dollars)						
Derivatives designated as cash flow hedges						
Interest rate	\$	—	\$	1,385 ^(a)	\$	—
Vehicle fuel and other commodity		(66)		73 ^(b)		—
Total	\$	(66)	\$	1,458	\$	—
Other derivative instruments						
Commodity trading	\$	—	\$	—	\$	(7,650) ^(c)
Electric commodity		—		(15,483)		14,735 ^(d)
Natural gas commodity		—		(4,878)		4,762 ^(e)
Total	\$	—	\$	(20,361)	\$	19,497
					\$	(11,235)

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Year Ended Dec. 31, 2014					
(Thousands of Dollars)	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains Recognized During the Period in Income
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	\$ —	\$ —	\$ 1,387 ^(a)	\$ —	\$ —
Vehicle fuel and other commodity	(150)	—	(30) ^(b)	—	—
Total	\$ (150)	\$ —	\$ 1,357	\$ —	\$ —
Other derivative instruments					
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ 751 ^(c)
Electric commodity	—	(4,385)	—	(17,200) ^(d)	—
Natural gas commodity	—	4,576	—	(8,584) ^(e)	(2,627) ^(e)
Other commodity	—	—	—	—	643 ^(c)
Total	\$ —	\$ 191	\$ —	\$ (25,784)	\$ (1,233)

(a) Amounts are recorded to interest charges.

(b) Amounts are recorded to operating expenses.

(c) Amounts are recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(d) Amounts are recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Amounts are recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

NSP-Minnesota had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2015 and 2014. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

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Credit Related Contingent Features — Contract provisions for derivative instruments that NSP-Minnesota enters into, including those recorded to the balance sheet at fair value, as well as those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheet, may require the posting of collateral or settlement of the contracts for various reasons, including if NSP-Minnesota is unable to maintain its credit ratings. At Dec. 31, 2015 and 2014, no derivative instruments in a liability position would have required the posting of collateral or settlement of outstanding contracts if the credit ratings of NSP-Minnesota were downgraded below investment grade.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that NSP-Minnesota's ability to fulfill its contractual obligations is reasonably expected to be impaired. NSP-Minnesota had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2015 and 2014.

Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, NSP-Minnesota's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2015:

	Dec. 31, 2015					
	Fair Value			Fair Value Total	Counterparty Netting ^(b)	Total
(Thousands of Dollars)	Level 1	Level 2	Level 3			
Current derivative assets						
Other derivative instruments:						
Commodity trading	88	10,269	1,250	11,607	(5,542)	6,065
Electric commodity	—	—	12,441	12,441	(167)	12,274
Natural gas commodity	—	128	—	128	(6)	122
Total current derivative assets	\$ 88	\$ 10,397	\$ 13,691	\$ 24,176	\$ (5,715)	18,461
PPAs ^(a)						480
Current derivative instruments						\$ 18,941
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	\$ —	\$ 27,399	\$ —	\$ 27,399	\$ (6,555)	\$ 20,844
Total noncurrent derivative assets	\$ —	\$ 27,399	\$ —	\$ 27,399	\$ (6,555)	20,844
PPAs ^(a)						1,490
Noncurrent derivative instruments						\$ 22,334

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(Thousands of Dollars)	Dec. 31, 2015					
	Fair Value			Fair Value	Counterparty	Total
	Level 1	Level 2	Level 3	Total	Netting ^(b)	
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	\$ —	\$ 113	\$ —	\$ 113	\$ —	\$ 113
Other derivative instruments:						
Commodity trading	118	7,541	554	8,213	(6,580)	1,633
Electric commodity	—	—	167	167	(167)	—
Natural gas commodity	—	1,362	—	1,362	(6)	1,356
Total current derivative liabilities	\$ 118	\$ 9,016	\$ 721	\$ 9,855	\$ (6,753)	\$ 3,102
PPAs ^(a)						14,109
Current derivative instruments						\$ 17,211
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	—	19,865	—	19,865	(9,780)	10,085
Total noncurrent derivative liabilities	\$ —	\$ 19,865	\$ —	\$ 19,865	\$ (9,780)	\$ 10,085
PPAs ^(a)						118,128
Noncurrent derivative instruments						\$ 128,213

- (a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, NSP-Minnesota began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, NSP-Minnesota qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.
- (b) NSP-Minnesota nets derivative instruments and related collateral in its balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2015. At Dec. 31, 2015, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of \$4.3 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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The following table presents for each of the fair value hierarchy levels, NSP-Minnesota's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2014:

	Dec. 31, 2014						
	Fair Value			Fair Value	Counterparty		
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total	Netting ^(b)	Total	
Current derivative assets							
Other derivative instruments:							
Commodity trading	\$ —	\$ 14,326	\$ 4,732	\$ 19,058	\$ (3,240)	\$ 15,818	
Electric commodity	—	—	37,051	37,051	(1,512)	35,539	
Natural gas commodity	—	295	—	295	(4)	291	
Total current derivative assets	<u>\$ —</u>	<u>\$ 14,621</u>	<u>\$ 41,783</u>	<u>\$ 56,404</u>	<u>\$ (4,756)</u>	51,648	
PPAs ^(a)						8,516	
Current derivative instruments						<u>\$ 60,164</u>	
Noncurrent derivative assets							
Other derivative instruments:							
Commodity trading	\$ —	\$ 17,617	\$ —	\$ 17,617	\$ (4,151)	\$ 13,466	
Total noncurrent derivative assets	<u>\$ —</u>	<u>\$ 17,617</u>	<u>\$ —</u>	<u>\$ 17,617</u>	<u>\$ (4,151)</u>	13,466	
PPAs ^(a)						1,968	
Noncurrent derivative instruments						\$ 15,434	

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	Dec. 31, 2014						
	Fair Value			Fair Value	Counterparty		
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total	Netting ^(b)	Total	
Current derivative liabilities							
Derivatives designated as cash flow hedges:							
Vehicle fuel and other commodity	\$ —	\$ 65	\$ —	\$ 65	\$ —	\$ 65	
Other derivative instruments:							
Commodity trading	—	7,974	—	7,974	(7,974)	—	
Electric commodity	—	—	1,512	1,512	(1,512)	—	
Total current derivative liabilities	\$ —	\$ 8,039	\$ 1,512	\$ 9,551	\$ (9,486)	65	
PPAs ^(a)							12,229
Current derivative instruments							\$ 12,294
Noncurrent derivative liabilities							
Derivatives designated as cash flow hedges:							
Vehicle fuel and other commodity	\$ —	\$ 56	\$ —	\$ 56	\$ —	\$ 56	
Other derivative instruments:							
Commodity trading	—	6,890	—	6,890	(6,033)	857	
Total noncurrent derivative liabilities	\$ —	\$ 6,946	\$ —	\$ 6,946	\$ (6,033)	913	
PPAs ^(a)							134,123
Noncurrent derivative instruments							\$ 135,036

- (a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, NSP-Minnesota began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, NSP-Minnesota qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.
- (b) NSP-Minnesota nets derivative instruments and related collateral in its balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2014. At Dec. 31, 2014, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of \$6.6 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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The following table presents the changes in Level 3 commodity derivatives for the years ended Dec. 31, 2015 and 2014:

(Thousands of Dollars)	Year Ended Dec. 31	
	2015	2014
Balance at Jan. 1	\$ 40,271	\$ 31,727
Purchases	40,288	84,762
Settlements	(38,050)	(101,690)
Transfers out of Level 3	—	(1,093)
Net transactions recorded during the period:		
Gains recognized in earnings (a)	1,533	10,692
(Losses) gains recognized as regulatory assets and liabilities	(31,072)	15,873
Balance at Dec. 31	\$ 12,970	\$ 40,271

(a) These amounts relate to commodity derivatives held at the end of the period.

NSP-Minnesota recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the year ended Dec. 31, 2015. The transfer of amounts from Level 3 to Level 2 in the year ended Dec. 31, 2014 was due to the valuation of certain long-term derivative contracts for which observable commodity pricing forecasts became a more significant input during the period.

Fair Value of Long-Term Debt

As of Dec. 31, 2015 and 2014, other financial instruments for which the carrying amount did not equal fair value were as follows:

(Thousands of Dollars)	2015		2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	\$ 4,534,122	\$ 4,917,080	\$ 4,188,682	\$ 4,803,735

The fair value of NSP-Minnesota's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of Dec. 31, 2015 and 2014, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

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8. Rate Matters

Pending and Recently Concluded Regulatory Proceedings — MPUC

Minnesota 2014 Multi-Year Electric Rate Case — In November 2013, NSP-Minnesota filed a two-year electric rate case with the MPUC. The rate case was based on a return on equity (ROE) of 10.25 percent, a 52.5 percent equity ratio, a 2014 average electric rate base of \$6.67 billion and an additional average rate base of \$412 million in 2015. The NSP-Minnesota electric rate case initially reflected a requested increase in revenues of approximately \$193 million, or 6.9 percent, in 2014 and an additional \$98 million, or 3.5 percent, in 2015. The request included a proposed rate moderation plan. In December 2013, the MPUC approved interim rates of \$127 million, effective Jan. 3, 2014, subject to refund. In 2014, NSP-Minnesota revised its requested rate increase to \$115.3 million for 2014 and to \$106.0 million for 2015, for a total combined unadjusted increase of \$221.3 million.

In May 2015, the MPUC ordered a total increase of \$166.1 million, or 5.9 percent, consisting of \$58.9 million and \$125.2 million in 2014 and 2015, respectively, and an \$18.0 million adjustment related to disallowance of certain Monticello LCM/EPU costs. The MPUC also approved a three-year, decoupling pilot with a 3 percent cap on base revenue for the residential and small commercial and industrial classes, based on actual sales, effective Jan. 1, 2016. The decoupling mechanism would eliminate the impact of changes in electric sales due to conservation and weather variability for these classes.

In July 2015, the MPUC deliberated on requests for reconsideration and determined the Monticello EPU project was not yet used-and-useful, as final approval related to the full EPU uprate condition had not been received from the NRC as of June 30, 2015.

As a result, \$13.8 million was excluded from final rates. Monticello subsequently received final NRC compliance approval in July 2015. The MPUC also approved 2015 interim rates effective March 3, 2015 and stated that the 2014 interim rate refund obligation be netted against the 2015 interim rate revenue under-collections.

The MPUC's decisions resulted in a total estimated 2014 and 2015 annual rate increase of \$149.4 million, or 5.3 percent.

The following table outlines the impact of the MPUC's July decision:

(Millions of Dollars)	MPUC July Decision
2014 and 2015 step increase - based on MPUC May order	\$ 166.1
Reconsideration/clarification adjustments:	
2015 Monticello EPU used-and-useful adjustment	(13.8)
2014 property tax final true-up	(3.1)
Other, net	0.2
Total 2014 and 2015 step increase	\$ 149.4
Impact of interim rate effective March 3, 2015	(3.6)
Estimated revenue impact	\$ 145.8

NSP-Minnesota – Minnesota 2016 Multi-Year Electric Rate Case — In November 2015, NSP-Minnesota filed a three-year electric rate case with the MPUC. The rate case is based on a requested ROE of 10.0 percent and a 52.50 percent equity ratio. The request is detailed in the table below.

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Request (Millions of Dollars)	2016	2017	2018
Rate request	\$ 194.6	\$ 52.1	\$ 50.4
Increase percentage	6.4%	1.7%	1.7%
Interim request	\$ 163.7	\$ 44.9	N/A
Rate base	\$ 7,800	\$ 7,700	\$ 7,700

NSP-Minnesota also proposed a five-year alternative plan that would extend the rate plan two additional years.

In addition, NSP-Minnesota has requested the MPUC encourage parties to engage in a formal mediation type procedure as outlined by Minnesota's rate case statute which may streamline the settlement process.

In December 2015, the MPUC approved interim rates for 2016. The MPUC deferred making a decision on incremental interim rates for 2017 and indicated that NSP-Minnesota could bring back its request in the fourth quarter of 2016. The MPUC also required NSP-Minnesota to file supplemental direct testimony addressing costs associated with the LCM at the PI nuclear plant. NSP-Minnesota filed supplemental testimony in January 2016 demonstrating that the capital work at PI, including the LCM, is required during the rate case period, higher costs associated with the LCM are necessary to operate the plant through the end of its licensed life and recovery of these costs will result in reasonably priced energy for customers.

The major components of the requested rate increase are summarized below:

(Millions of Dollars)	2016	2017	2018	Total
2014 multi-year rate case items:				
Excess depreciation reserve	\$ 26.0	\$ 51.0	\$ —	\$ 77.0
DOE settlement	25.7	—	—	25.7
Monticello LCM/EPU	11.2	(1.6)	(1.5)	8.1
	62.9	49.4	(1.5)	110.8
Additional items:				
Capital investments	128.7	12.8	44.6	186.1
Property taxes	30.2	7.6	5.2	43.0
NOL carryforwards	(6.3)	(24.5)	(6.5)	(37.3)
Other costs	(20.9)	6.8	8.6	(5.5)
	131.7	2.7	51.9	186.3
Total rate request	\$ 194.6	\$ 52.1	\$ 50.4	\$ 297.1

The next steps in the procedural schedule are expected to be as follows:

- Intervenor's direct testimony — June 14, 2016;
- Rebuttal testimony — Aug. 9, 2016;
- Surrebuttal testimony — Sept. 16, 2016;
- Settlement conference — Sept. 26, 2016;
- Evidentiary hearing — Oct. 4-7, 2016;

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- Administrative law judge (ALJ) report — Feb. 21, 2017; and
- MPUC order — June 1, 2017.

Nuclear Project Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello LCM/EPU project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 MW. The Monticello LCM/EPU project expenditures were approximately \$665 million. Total capitalized costs were approximately \$748 million, which includes AFUDC. In 2008, project expenditures were initially estimated at approximately \$320 million, excluding AFUDC.

In 2013, the MPUC initiated an investigation to determine whether the final costs for the Monticello LCM/EPU project were prudent.

In March 2015, the MPUC voted to allow for full recovery, including a return, on approximately \$415 million of the total plant costs (inclusive of AFUDC), but only allow recovery of the remaining \$333 million of costs with no return on this portion of the investment over the remaining life of the plant. Further, the MPUC determined that only 50 percent of the investment was considered used-and-useful for 2014. As a result of these determinations, Xcel Energy recorded an estimated pre-tax loss of \$129 million in the first quarter of 2015, after which the remaining book value of the Monticello project represented the present value of the estimated future cash flows.

NSP-Minnesota – 2016 Transmission Cost Recovery Adjustment (TCR) Filing — In October 2015, NSP-Minnesota submitted its 2016 TCR filing with the MPUC, requesting recovery of \$19.2 million of 2016 transmission investment costs not included in electric base rates. This filing included an option to keep approximately \$59.1 million of revenue requirements associated with two CapX2020 projects completed in 2015 within the TCR rider or to include these revenue requirements in electric base rates during the interim rate implementation of the next electric rate case. In November 2015, NSP-Minnesota submitted an update to its TCR filing in which it confirmed that it was requesting the MPUC approve keeping the two CapX2020 projects in the TCR rider, increasing the revenue requirements to \$78.3 million, until the conclusion of the 2016 Minnesota electric rate case.

Recently Concluded Regulatory Proceedings — South Dakota Public Service Commission (SDPUC)

NSP-Minnesota – South Dakota Infrastructure Rider — In December 2015, the SDPUC approved recovery of \$10.2 million through the infrastructure rider effective beginning Jan. 1, 2016. As part of the South Dakota 2015 electric rate case, the infrastructure rider was refreshed with new projects and was also expanded as a mechanism to allow for possible recovery of other investments related to generation, transmission, and distribution.

Electric, Purchased Gas and Resource Adjustment Clauses

CIP and CIP Rider — In December 2012, the MPUC approved reductions to the CIP financial incentive mechanisms effective for the 2013 through 2015 program years and in 2015 extended the mechanisms to the 2016 program year. The estimated average annual electric and natural gas incentives are \$30.6 million and \$3.6 million, respectively, based on the approved savings goals.

CIP expenses are recovered through base rates and a rider that is adjusted annually.

- In July 2015, the MPUC approved NSP-Minnesota's 2014 CIP electric and natural gas financial incentives totaling \$40.1 million and \$5.8 million, respectively.

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- In addition, the MPUC approved NSP-Minnesota's proposed 2015 to 2016 electric and natural gas CIP riders. NSP-Minnesota estimates 2016 recovery of \$21.5 million of electric CIP expenses and \$9.2 million of natural gas CIP expenses.
- This proposed recovery through the riders is in addition to an estimated \$86.9 million and \$3.7 million through electric and gas base rates, respectively.

NSP-Minnesota – Gas Utility Infrastructure Cost (GUIC) Rider — In October 2015, NSP-Minnesota filed the GUIC rider with the MPUC for approval to recover the cost of natural gas infrastructure investments in Minnesota to improve safety and reliability. Costs include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs. Sewer separation costs stem from the inspection of sewer lines and the redirection of gas pipes in the event their paths are in conflict. NSP-Minnesota requested recovery of approximately \$15.5 million from Minnesota gas utility customers beginning April 1, 2016. This request includes \$1.9 million in over-recovery from 2015 and \$4.5 million of deferred sewer separation and integrity management costs which is the 2016 portion of a five year amortization.

An MPUC decision is expected in the second half of 2016.

Pending Regulatory Proceedings — FERC

MISO ROE Complaints/ROE Adder — In November 2013, a group of customers filed a complaint at the FERC against MISO transmission owners (TOs), including NSP-Minnesota and NSP-Wisconsin. The complaint argued for a reduction in the ROE in transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, a prohibition on capital structures in excess of 50 percent equity, and the removal of ROE adders (including those for RTO membership and being an independent transmission company), effective Nov. 12, 2013.

Subsequently, the FERC adopted a new ROE methodology, which requires electric utilities to use a two-step discounted cash flow analysis that incorporates both short-term and long-term growth projections to estimate the cost of equity.

The ROE complaint was set for full hearing procedures. The complainants and intervenors filed testimony recommending a ROE between 8.67 percent and 9.54 percent. The FERC staff recommended a ROE of 8.68 percent. The MISO TOs recommended a ROE not less than 10.8 percent. In December 2015, an ALJ initial decision was issued recommending a ROE of 10.32 percent. Briefs on exceptions challenging the ALJ recommendation were filed in January 2016. A FERC order is expected to be issued later in 2016.

Certain MISO TOs separately requested FERC approval of a 50 basis point ROE adder for RTO membership, which was approved effective Jan. 6, 2015, subject to the outcome of the ROE complaint. The total ROE, including the RTO membership adder, may not exceed the top of the discounted cash flow range under the new ROE methodology. Certain intervenors sought rehearing of the FERC order granting the ROE adder and FERC action is pending.

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In February 2015, certain intervenors filed a second complaint to reduce the MISO region ROE to 8.67 percent, prior to an adder. FERC set the second complaint for hearings, and established a refund effective date of Feb. 12, 2015. The complainants and intervenors filed direct testimony in September 2015, the MISO TOs filed answering testimony in October 2015 and FERC staff filed testimony in November 2015. In January 2016, all parties updated their ROE analyses. The complainants and intervenors recommended ROEs between 8.72 percent and 9.32 percent while FERC staff recommended a ROE of 8.78 percent. The MISO TOs recommended a ROE of 10.96 percent. Hearings were held before an ALJ in February 2016. An ALJ initial decision is expected in June 2016 with a FERC decision expected in late 2016 or 2017.

NSP-Minnesota recorded a current liability representing the current best estimate of a refund obligation associated with the new ROE, including the RTO membership adder, as of Dec. 31, 2015. The new FERC ROE methodology is estimated to reduce transmission revenue, net of expense, between \$8 million and \$10 million annually for the NSP System.

9. Commitments and Contingencies

Commitments

Fuel Contracts — NSP-Minnesota has entered into various long-term commitments for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2016 and 2033. NSP-Minnesota is required to pay additional amounts depending on actual quantities shipped under these agreements.

The estimated minimum purchases for NSP-Minnesota under these contracts as of Dec. 31, 2015, are as follows:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2016	\$ 273.4	\$ 112.2	\$ 35.0	\$ 99.9
2017	141.9	112.3	2.5	84.7
2018	106.8	62.7	—	43.5
2019	—	124.1	—	38.1
2020	—	46.9	—	27.9
Thereafter	—	599.2	—	185.0
Total ^(a)	\$ 522.1	\$ 1,057.4	\$ 37.5	\$ 479.1

(a) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Additional expenditures for fuel and natural gas storage and transportation will be required to meet expected future electric generation and natural gas needs. NSP-Minnesota's risk of loss, in the form of increased costs from market price changes in fuel, is mitigated through the use of natural gas and energy cost-rate adjustment mechanisms, which provide for pass-through of most fuel, storage and transportation costs to customers.

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PPAs — NSP-Minnesota has entered into PPAs with other utilities and energy suppliers with expiration dates through 2039 for purchased power to meet system load and energy requirements and meet operating reserve obligations. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts also contain minimum energy purchase commitments. Capacity and energy payments are typically contingent on the independent power producing entity meeting certain contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs, accounted for as executory contracts, were payments for capacity of \$104.4 million and \$107.9 million in 2015 and 2014, respectively. At Dec. 31, 2015, the estimated future payments for capacity and energy that NSP-Minnesota is obligated to purchase pursuant to these executory contracts, subject to availability, are as follows:

(Millions of Dollars)	Capacity	Energy (a)
2016	\$ 89.7	\$ 81.6
2017	83.5	87.3
2018	52.8	93.2
2019	53.8	98.7
2020	54.8	105.4
Thereafter	310.5	662.5
Total (b)	\$ 645.1	\$ 1,128.7

(a) Excludes contingent energy payments for renewable energy PPAs.

(b) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Additional energy payments under these PPAs and PPAs accounted for as operating leases will be required to meet expected future electric demand.

Leases — NSP-Minnesota leases a variety of equipment and facilities used in the normal course of business. These leases, primarily for office space, railcars, generating facilities, trucks, aircraft, cars and power-operated equipment, are accounted for as operating leases. Total expenses under operating lease obligations were approximately \$78.9 million and \$81.0 million for 2015 and 2014, respectively. These expenses include capacity payments for PPAs accounted for as operating leases of \$61.5 million and \$61.0 million in 2015 and 2014, respectively, recorded to electric fuel and purchased power expenses.

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Included in electric fuel and purchased power expenses for PPAs, accounted for as executory contracts, were payments for capacity of \$104.4 million and \$107.9 million in 2015 and 2014, respectively. At Dec. 31, 2015, the estimated future payments for capacity and energy that NSP-Minnesota is obligated to purchase pursuant to these executory contracts, subject to availability, are as follows:

(Millions of Dollars)	PPA Operating Leases		
	Operating Leases	(a) (b)	Total Operating Leases
2015	\$ 7.7	\$ 63.3	\$ 71.0
2016	8.4	64.4	72.8
2017	8.2	65.4	73.6
2018	12.7	82.3	95.0
2019	7.8	95.0	102.8
Thereafter	65.2	938.2	1,003.4

(a) Amounts do not include PPAs accounted for as executory contracts.

(b) PPA operating leases contractually expire through 2039.

Guarantees — Under NSP-Minnesota's railcar lease agreement, accounted for as an operating lease, NSP-Minnesota guarantees the lessor proceeds from sale of the leased assets at the end of the lease term will at least equal the guaranteed residual value. The guarantee issued by NSP-Minnesota limits its exposure to a maximum amount stated in the guarantee; however, NSP-Minnesota expects sale proceeds to exceed the guaranteed amount.

The following table presents the guarantee issued and outstanding for NSP-Minnesota:

(Millions of Dollars)	Guarantee Amount	Current Exposure	Term or Expiration Date	Triggering Event
Guarantee of residual value of assets under the Bank of Tokyo-Mitsubishi Capital Corporation Equipment Leasing Agreement	\$ 4.8	\$ —	2019	(a)

(a) Actual fair value of leased assets is less than the guaranteed residual value amount at the end of the lease term.

Environmental Contingencies

NSP-Minnesota has been or is currently involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, NSP-Minnesota believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, NSP-Minnesota is pursuing, or intends to pursue, recovery from other PRPs and through the regulated rate process. New and changing federal and state environmental mandates can also create added financial liabilities for NSP-Minnesota, which are normally recovered through the regulated rate process. To the extent any costs are not recovered through the options listed above, NSP-Minnesota would be required to recognize an expense.

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Site Remediation — Various federal and state environmental laws impose liability, without regard to the legality of the original conduct, where hazardous substances or other regulated materials have been released to the environment. NSP-Minnesota may sometimes pay all or a portion of the cost to remediate sites where past activities of NSP-Minnesota or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former manufactured gas plants (MGPs) operated by NSP-Minnesota, its predecessors, or other entities; and third-party sites, such as landfills, for which NSP-Minnesota is alleged to be a PRP that sent wastes to that site.

MGP Sites

Fargo, N.D. MGP Site — In May 2015, in connection with a city water main replacement and street improvement project in Fargo, N.D., underground pipes, tars and impacted soils, which may be related to a former MGP site operated by NSP-Minnesota or a prior company, were discovered. After initial reports and discussions with the City of Fargo and the North Dakota Department of Health, NSP-Minnesota removed the impacted soils and other materials from the project area. NSP-Minnesota is undertaking further investigation of the location of the historic MGP site and nearby properties. At this time, NSP-Minnesota's investigation of the site is preliminary as information is still being gathered. In October 2015, NSP-Minnesota initiated insurance recovery litigation in North Dakota. The U.S. District Court for the District of North Dakota will likely establish a scheduling order for the case in the first quarter of 2016.

As of Dec. 31, 2015, NSP-Minnesota had recorded a liability of \$2.7 million related to further investigation and additional planned activities. Uncertainties include the nature and cost of the additional remediation efforts that may be necessary, the ability to recover costs from insurance carriers and the potential for contributions from entities that may be identified as PRPs. Therefore, the total cost of remediation, NSP-Minnesota's potential liability and amounts allocable to the North Dakota and Minnesota jurisdictions related to the site cannot currently be reasonably estimated. In July 2015, NSP-Minnesota filed a request with the NDPSC for approval to initially defer the portion of investigation and response costs allocable to the North Dakota jurisdiction. In December 2015, the NDPSC approved NSP-Minnesota's request.

Other MGP Sites — NSP-Minnesota is currently involved in investigating and/or remediating several other MGP sites where regulated materials may have been deposited. NSP-Minnesota has identified four sites where former MGP activities have or may have resulted in site contamination and are under current investigation and/or remediation. At some or all of these MGP sites, there are other parties that may have responsibility for some portion of any remediation. NSP-Minnesota anticipates that the majority of the remediation at these sites will continue through at least 2016. NSP-Minnesota had accrued \$0.2 million and \$0.1 million for all of these sites at Dec. 31, 2015 and Dec. 31, 2014, respectively. There may be insurance recovery and/or recovery from other PRPs that will offset any costs incurred. NSP-Minnesota anticipates that any amounts spent will be fully recovered from customers.

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Environmental Requirements

Water and Waste

Asbestos Removal — Some of NSP-Minnesota’s facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or removed. NSP-Minnesota has recorded an estimate for final removal of the asbestos as an ARO. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is not expected to be material and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Federal Clean Water Act (CWA) Effluent Limitations Guidelines (ELG) —In September 2015, the EPA issued a final ELG rule for power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. NSP-Minnesota has reviewed the final rule and is in the process of evaluating whether the costs of compliance could have a material impact on the results of operations, financial position or cash flows. NSP-Minnesota believes that compliance costs would be recoverable through regulatory mechanisms.

Federal CWA Section 316(b) — Section 316(b) of the federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse environmental impacts to aquatic species. The EPA published the final 316(b) rule in August 2014. The rule prescribes technology for protecting fish that get stuck on plant intake screens (known as impingement) and describes a process for site-specific determinations by each state for sites that must protect the small aquatic organisms that pass through the intake screens into the plant cooling systems (known as entrainment). The timing of compliance with the requirements will vary from plant-to-plant since the new rule does not have a final compliance deadline. NSP-Minnesota estimates the likely cost for complying with impingement requirements may be incurred between 2016 and 2027 and is approximately \$45 million. NSP-Minnesota believes at least six plants could be required by state regulators to make improvements to reduce entrainment. The exact cost of the entrainment improvements is uncertain, but could be up to \$190 million depending on the outcome of certain entrainment studies and cost-benefit analyses. NSP-Minnesota anticipates these costs will be fully recoverable in rates.

Federal CWA Waters of the United States Rule — In June 2015, the EPA and the U.S. Army Corps of Engineers published a final rule that significantly expands the types of water bodies regulated under the CWA and broadens the scope of waters subject to federal jurisdiction. The expansion of the term “Waters of the U.S.” will subject more utility projects to federal CWA jurisdiction, thereby potentially delaying the siting of new generation projects, pipelines, transmission lines and distribution lines, as well as increasing project costs and expanding permitting and reporting requirements. The rule went into effect in August 2015. In October 2015, the U.S. Court of Appeals for the Sixth Circuit issued a nationwide stay of the final rule, pending further legal proceedings.

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Air

Greenhouse Gas (GHG) Emission Standard for Existing Sources (Clean Power Plan or CPP) — In October 2015, a final rule was published by the EPA for GHG emission standards for existing power plants. States must develop implementation plans by September 2016, with the possibility of an extension to September 2018, or the EPA will prepare a federal plan for the state. Among other things, the rule requires that state plans include enforceable measures to ensure emissions from existing power plants achieve the EPA's state-specific interim (2022-2029) and final (2030 and thereafter) emission performance targets. The CPP is currently being challenged by multiple parties in the D.C. Circuit Court. In January 2016, the D.C. Circuit Court denied requests to stay the effectiveness of the rule as well as ordered expedited review of the CPP, with briefings to be completed and oral arguments held by June 2016. Following the D.C. Circuit Court's denial of motions for stay, multiple parties filed requests for stay with the U.S. Supreme Court. In February 2016, the U.S. Supreme Court issued an order staying the final CPP rule. The stay will remain in effect until, first, the D.C. Circuit Court and then the U.S. Supreme Court have ruled on the challenges to the CPP.

NSP-Minnesota has undertaken a number of initiatives that reduce GHG emissions and respond to state renewable and energy efficiency goals. The CPP could require additional emission reductions in states in which NSP-Minnesota operates. If state plans do not provide credit for the investments we have already made to reduce GHG emissions, or if they require additional initiatives or emission reductions, then their requirements would potentially impose additional substantial costs. Until NSP-Minnesota has more information about SIPs or knows the requirements of the EPA's upcoming final rule on federal plans for the states that do not develop related plans, NSP-Minnesota cannot predict the costs of compliance with the final rule once it takes effect. NSP-Minnesota believes compliance costs will be recoverable through regulatory mechanisms. If our regulators do not allow us to recover all or a part of the cost of capital investment or the operating costs incurred to comply with the CPP or cost recovery is not provided in a timely manner, it could have a material impact on results of operations, financial position or cash flows.

Cross-State Air Pollution Rule (CSAPR) — CSAPR addresses long range transport of particulate matter (PM) and ozone by requiring reductions in SO₂ and NO_x from utilities in the eastern half of the United States, including Minnesota, using an emissions trading program. CSAPR compliance in 2015 did not and 2016 is not expected to have a material impact on the results of operations, financial position or cash flows.

CSAPR was adopted to address interstate emissions impacting downwind states' attainment of the 1997 ozone National Ambient Air Quality Standard (NAAQS) and the 1997 and 2006 particulate NAAQS. As the EPA revises the NAAQS, it will consider whether to make any further reductions to CSAPR emission budgets and whether to change which states are included in the emissions trading program. In December 2015, the EPA proposed adjustments to CSAPR emission budgets which address attainment of the more stringent 2008 ozone NAAQS. If adopted as proposed, the ozone season emission budget for NO_x is not expected to impact NSP-Minnesota.

Regional Haze Rules — The regional haze program is designed to address widespread haze that results from emissions from a multitude of sources. In 2005, the EPA amended the best available retrofit technology (BART) requirements of its regional haze rules, which require the installation and operation of emission controls for industrial facilities emitting air pollutants that reduce visibility in certain national parks and wilderness areas. In its first regional haze SIP, Minnesota identified the NSP-Minnesota facilities that will have to reduce SO₂, NO_x and PM emissions under BART and set emissions limits for those facilities.

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In 2009, the Minnesota Pollution Control Agency (MPCA) approved a SIP and submitted it to the EPA for approval. The MPCA's source-specific BART limits for Sherco Units 1 and 2 require combustion controls for NO_x and scrubber upgrades for SO₂. The MPCA supplemented its SIP in 2012, determining that CSAPR meets BART requirements, but also implementing its source-specific BART determination for Sherco Units 1 and 2 from the 2009 SIP. In June 2012, the EPA approved the state implementation plan (SIP) for electric generating units (EGUs) and also approved the source-specific emission limits for Sherco Units 1 and 2. The combustion controls were installed first and the scrubber upgrades were completed in December 2014, at a cost of \$46.9 million. NSP-Minnesota has included these costs for recovery in rate proceedings.

In August 2012, the National Parks Conservation Association, Sierra Club, Voyageurs National Park Association, Friends of the Boundary Waters Wilderness, Minnesota Center for Environmental Advocacy and Fresh Energy appealed the EPA's approval of the Minnesota SIP to the U.S. Court of Appeals for the Eighth Circuit (Eighth Circuit). In June 2013, the Eighth Circuit ordered this case to be held in abeyance until the U.S. Supreme Court decided the CSAPR case. In January 2016, the Eighth Circuit issued their opinion which upheld the EPA's approval of the SIP.

Reasonably Attributable Visibility Impairment (RAVI) — RAVI is intended to address observable impairment from a specific source such as distinct, identifiable plumes from a source's stack to a national park. In 2009, the United States Department of the Interior (DOI) certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from NSP-Minnesota's Sherco Units 1 and 2.

In December 2012, a lawsuit against the EPA was filed in the U.S. District Court for the District of Minnesota (Minnesota District Court) by the following organizations: National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyageurs National Park Association, Fresh Energy and Sierra Club.

In May 2015, NSP-Minnesota, the EPA and the six environmental advocacy organizations filed a settlement agreement in the Minnesota District Court. The agreement anticipates a federal rulemaking that would impose stricter SO₂ emission limits on Sherco Units 1, 2 and 3, without making a RAVI attribution finding or a RAVI BART determination. The emission limits for Units 1 and 2 reflect the success of a recently completed control project. The Unit 3 emission limits will be met through changes in the operation of the existing scrubber. The Minnesota District Court issued an order staying the litigation for the time needed to complete the actions required by the settlement agreement. The plaintiffs agreed to withdraw their complaint with prejudice when those actions are completed. Plaintiffs also agreed not to request a RAVI certification for Sherco Units 1, 2 and/or 3 in the future.

After a public comment period, the EPA notified the Minnesota District Court, in July 2015, that the settlement agreement is final. The EPA has seven months to recommend and adopt a rule which will set the agreed-upon SO₂ emissions. In October 2015, the EPA proposed a rule that would set the agreed-upon SO₂ emission limits. No public comments were received on this proposal. The EPA published a final rule effectuating the settlement in March 2016. Also in March 2016, the Minnesota District Court issued an order dismissing the complaint with prejudice. NSP-Minnesota does not anticipate the costs of compliance with the proposed settlement will have a material impact on the results of operations, financial position or cash flows.

Implementation of the NAAQS for SO₂ — The EPA adopted a more stringent NAAQS for SO₂ in 2010. In 2013, the EPA designated areas as not attaining the revised NAAQS, which did not include any areas where NSP-Minnesota operates power plants. However, many other areas of the country were unable to be classified by the EPA due to a lack of air monitors.

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Following a lawsuit alleging that the EPA had not completed its area designations in the time required by the CAA and under a consent decree the EPA is requiring states to evaluate areas in three phases. If an area is designated nonattainment, the respective states will need to evaluate all SO₂ sources in the area. The state would then submit an implementation plan for the respective areas which would be due in 18 months, designed to achieve the NAAQS within five years. It is anticipated the areas near NSP-Minnesota's power plants would be evaluated in the next designation phase, ending December 2017. NSP-Minnesota cannot evaluate the impacts of this ruling until the designation of nonattainment areas is made and any required state plans are developed.

Revisions to the NAAQS for Ozone — In October 2015, the EPA revised the NAAQS for ozone by lowering the eight-hour standard from 75 parts per billion (ppb) to 70 ppb. In areas where NSP-Minnesota operates, current monitored air quality concentrations comply with the new standard in the Twin Cities Metropolitan Area in Minnesota. In documents issued with the new standard, the EPA projects the Twin Cities Metropolitan Area will meet the new standard. Therefore, NSP-Minnesota does not expect a material impact on results of operations, financial position or cash flows.

Notice of Violation (NOV) — In 2011, NSP-Minnesota received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the CAA at the Sherco plant and Black Dog plant in Minnesota. The NOV alleges that various maintenance, repair and replacement projects at the plants in the mid-2000s should have required a permit under the NSR process. NSP-Minnesota believes it has acted in full compliance with the CAA and NSR process. NSP-Minnesota also believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. NSP-Minnesota disagrees with the assertions contained in the NOV and intends to vigorously defend its position. It is not known whether any costs would be incurred as a result of this NOV.

Asset Retirement Obligations

Recorded AROs — AROs have been recorded for property related to the following: electric production (nuclear, steam, wind, other and hydro), electric distribution and transmission, natural gas transmission and distribution, and general property. The electric production obligations include asbestos, ash-containment facilities, radiation sources, storage tanks, control panels and decommissioning. The asbestos recognition associated with electric production includes certain plants. NSP-Minnesota also recognized asbestos obligations for its general office building. AROs also have been recorded for NSP-Minnesota steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. NSP-Minnesota has also recorded AROs for the retirement and removal of assets at certain wind production facilities for which the land is leased and removal is required by contract.

NSP-Minnesota has recognized an ARO for the retirement costs of natural gas mains and lines and for the removal of electric transmission and distribution equipment, which consists of many small potential obligations associated with polychlorinated biphenyls, mineral oil, storage tanks, lithium batteries, mercury and street lighting lamps. The electric and common general AROs include small obligations related to storage tanks, radiation sources and office buildings.

In April 2015, the EPA published the final rule regulating the management and disposal of coal combustion byproducts (e.g., coal ash) as a nonhazardous waste to the Federal Register. The rule became effective in October 2015. The estimated costs to comply with the final rule were incorporated into the cash flow revisions in 2015.

For the nuclear assets, the ARO is associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and PI. See Note 10 for further discussion of nuclear obligations.

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A reconciliation of NSP-Minnesota's AROs for the years ended Dec. 31, 2015 and 2014 is as follows:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2015	Liabilities Recognized	Liabilities Settled	Accretion	Revisions to Prior Estimates ^(b)	Ending Balance Dec. 31, 2015
Electric plant						
Nuclear production decommissioning	\$ 2,037,947	-	-	103,077	-	\$ 2,141,024
Steam production ash containment	63,730	-	-	1,878	(6,920)	58,688
Steam, hydro and other production asbestos	13,839	4,002	(130)	784	7,197	25,692
Wind production	36,165	31,085 ^(a)	-	1,760	644	69,654
Electric distribution	5,048	-	-	183	196	5,427
Steam, hydro and other production miscellaneous	1,668	-	(143)	62	76	1,663
Electric transmission	180	-	-	6	-	186
Steam production radiation sources	55	-	-	4	8	67
Natural gas plant						
Gas transmission and distribution	26,362	-	-	1,035	-	27,397
Common and other property						
Common general plant asbestos	505	-	-	27	19	551
Common miscellaneous	675	-	-	24	44	743
Total liability	<u>\$ 2,186,174</u>	<u>35,087</u>	<u>(273)</u>	<u>108,840</u>	<u>1,264</u>	<u>\$ 2,331,092</u>

(a) The liability recognized relates to the Pleasant Valley and Border Wind Farms which were placed in service during 2015.

(b) In 2015, AROs were revised for changes in estimated cash flows and the timing of those cash flows. Changes in the asbestos and ash containment AROs were mainly related to updated cost estimates.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$1.7 billion as of Dec. 31, 2015, consisting of external investment funds.

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(Thousands of Dollars)	Beginning Balance Jan. 1, 2014	Liabilities Recognized	Liabilities Settled	Accretion	Revisions to Prior Estimates ^(a)	Ending Balance Dec. 31, 2014 ^(b)
Electric plant						
Nuclear production decommissioning	\$ 1,628,298	-	-	86,284	323,365	\$ 2,037,947
Steam production ash containment	48,947	-	-	1,393	13,390	63,730
Steam, hydro and other production asbestos	13,303	-	-	536	-	13,839
Wind production	34,511	-	-	1,654	-	36,165
Electric distribution	4,871	-	-	177	-	5,048
Steam, hydro and other production miscellaneous	1,167	456	-	45	-	1,668
Electric transmission	174	-	-	6	-	180
Steam production radiation sources	49	-	-	3	3	55
Natural gas plant						
Gas transmission and distribution	333	2,281	-	22	23,726	26,362
Common and other property						
Common general plant asbestos	480	-	-	25	-	505
Common miscellaneous	630	-	-	23	22	675
Total liability	<u>\$ 1,732,763</u>	<u>2,737</u>	<u>-</u>	<u>90,168</u>	<u>360,506</u>	<u>\$ 2,186,174</u>

- (a) In 2014, revisions were made to various AROs due to revised estimated cash flows and the timing of those cash flows. Changes to estimated nuclear production decommissioning primarily relate to the triennial filing made to the MPUC in December 2014. See additional information in Note 10. Changes in estimated excavation costs and the timing of future retirement activities resulted in revisions to AROs related to gas transmission and distribution.
- (b) There were no ARO liabilities settled during the year ended Dec. 31, 2014.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$1.7 billion as of Dec. 31, 2014, consisting of external investment funds.

Indeterminate AROs — Outside of the known and recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of NSP-Minnesota's facilities, but no confirmation or measurement of the amount of asbestos or cost of removal could be determined as of Dec. 31, 2015. Therefore, an ARO has not been recorded for these facilities.

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to \$13.5 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured \$375 million of coverage for its public liability exposure with a pool of insurance companies. The remaining \$13.1 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to \$127.3 million per reactor per accident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is \$19.0 million per reactor during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective September 2013.

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NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are \$2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately \$19.9 million for business interruption insurance and \$43.7 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

NSP-Minnesota is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on NSP-Minnesota's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Other Contingencies

See Note 8 for further discussion.

10. Nuclear Obligations

Fuel Disposal — NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP-Minnesota's nuclear plants as well as from other U.S. nuclear plants, but no such facility is yet available. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. Through May 2014, the fuel disposal fees were based on a charge of 0.1 cent per KWh sold to customers from nuclear generation. Since that time, the DOE has set the fee to zero.

Fuel expense includes the DOE fuel disposal assessments of approximately \$5 million in 2014. There were no DOE fuel disposal assessments in 2015. In total, NSP-Minnesota paid approximately \$452.1 million to the DOE through Dec. 31, 2015.

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NSP-Minnesota has its own temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities at both sites. The amount of spent fuel storage capacity is determined by the NRC and the MPUC. The Monticello dry-cask storage facility currently stores 15 of the 30 authorized canisters, and the PI dry-cask storage facility currently stores 40 of the 64 authorized casks. Other alternatives for spent fuel storage are being investigated until a DOE facility is available.

Regulatory Plant Decommissioning Recovery — Decommissioning activities related to NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's operating license and be completed by 2091. NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit. The MPUC most recently approved NSP-Minnesota's 2014 nuclear decommissioning study in October 2015. This cost study quantified decommissioning costs in 2014 dollars and utilized escalation rates of 4.36 percent per year for plant removal activities, and 3.36 percent for spent fuel management and site restoration activities over a 60-year decommissioning scenario.

The total obligation for decommissioning is expected to be funded 100 percent by the external decommissioning trust fund when decommissioning commences. NSP-Minnesota's most recently approved decommissioning study resulted in an annual funding requirement of \$14 million to be recovered in utility customer rates starting in 2016. This cost study assumes the external decommissioning fund will earn an after-tax return between 5.23 percent and 6.30 percent. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs.

As of Dec. 31, 2015, NSP-Minnesota has accumulated \$1.7 billion of assets held in external decommissioning trusts. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation based on parameters established in the most recently approved decommissioning study. Xcel Energy believes future decommissioning costs, if necessary, will continue to be recovered in customer rates. The amounts presented below were prepared on a regulatory basis, and are not recorded in the financial statements for the ARO.

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(Thousands of Dollars)	Regulatory Basis	
	2015	2014
Estimated decommissioning cost obligation from most recently approved study (in 2014 and 2011 dollars, respectively)	\$ 3,012,342	\$ 2,694,079
Effect of escalating costs (to 2015 and 2014 dollars, respectively, at 4.36/3.36 percent and 3.63/2.63 percent, respectively)	126,464	289,907
Estimated decommissioning cost obligation (in current dollars)	3,138,806	2,983,986
Effect of escalating costs to payment date (4.36/3.36 percent and 3.63/2.63 percent, respectively)	8,066,688	5,597,302
Estimated future decommissioning costs (undiscounted)	11,205,494	8,581,288
Effect of discounting obligation (using average risk-free interest rate of 3.01 percent and 2.82 percent for 2015 and 2014, respectively)	(6,891,392)	(5,044,470)
Discounted decommissioning cost obligation	\$ 4,314,102	\$ 3,536,818
Assets held in external decommissioning trust	\$ 1,724,150	\$ 1,703,921
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	2,589,952	1,832,897

Calculations and data used by the regulator in approving company rates are useful in assessing future cash flows. The regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting. The following table provides a reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Thousands of Dollars)	2015	2014
Discounted decommissioning cost obligation - regulated basis	\$ 4,314,102	\$ 3,536,818
Differences in discount rate and market risk premium	(1,275,438)	(1,275,101)
Operating costs not included for GAAP	(897,640)	(547,135)
Differences in cost studies (2011 versus 2014, no change in 2015)	—	323,365
Nuclear production decommissioning ARO - GAAP	\$ 2,141,024	\$ 2,037,947

Decommissioning expenses recognized as a result of regulation for the years ending Dec. 31 were:

(Thousands of Dollars)	2015	2014
Annual decommissioning recorded as depreciation expense: (a)	\$ 6,862	\$ 7,138

(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

The 2014 nuclear decommissioning filing approved in 2015 has been used for the regulatory presentation.

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11. Regulatory Assets and Liabilities

NSP-Minnesota's financial statements are prepared in accordance with the applicable accounting guidance, as discussed in Note 1. Under this guidance, regulatory assets and liabilities are created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of the business that is not rate regulated cannot establish regulatory assets and liabilities. If changes in the utility industry or the business of NSP-Minnesota no longer allow for the application of regulatory accounting guidance under GAAP, NSP-Minnesota would be required to recognize the write-off of regulatory assets and liabilities in net income or OCI.

The components of regulatory assets shown on the balance sheets of NSP-Minnesota at Dec. 31, 2015 and 2014 are:

(Thousands of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Regulatory Assets		
Asset retirement recovery	\$ 1,851,864	\$ 1,731,065
Pension and retiree medical obligations ^(a)	378,580	376,202
Theoretical depreciation reserve surplus	237,420	161,609
Recoverable deferred taxes on AFUDC recorded in plant	204,089	200,525
Contract valuation adjustments ^(b)	134,103	139,632
Nuclear refueling outage costs	96,458	82,244
Renewable resources and environmental initiatives	59,494	54,635
Purchased power contracts costs	41,536	40,312
Conservation programs ^(c)	9,710	112
Sherco Unit 3 Deferral	9,596	10,063
Other	35,197	31,981
Other regulatory assets	<u>\$ 3,058,047</u>	<u>\$ 2,828,380</u>

(a) Includes \$257.5 million and \$282.4 million for the regulatory recognition of pension expense at Dec. 31, 2015 and 2014, respectively. Also included are \$0.6 million and \$2.9 million of regulatory assets related to the non-qualified pension plan at Dec. 31, 2015 and 2014.

(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(c) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

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The components of regulatory liabilities shown on the balance sheets of NSP-Minnesota at Dec. 31, 2015 and 2014 are:

(Thousands of Dollars)	Dec. 31, 2015	Dec. 31, 2014
Regulatory Liabilities		
Plant removal costs	\$ 1,468,068	\$ 1,438,394
Unrealized gains on nuclear decommissioning trust investments	164,897	172,651
Deferred income tax adjustment	27,181	28,262
Investment tax credit deferrals	24,968	20,614
DOE Settlement	12,755	42,922
Contract valuation adjustments ^(a)	12,274	35,540
Deferred electric energy costs	9,112	10,521
Conservation programs ^(b)	—	68,690
Other	14,138	17,483
Other regulatory liabilities ^(c)	\$ 1,733,393	\$ 1,835,077

(a) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(b) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

At Dec. 31, 2015 and 2014, approximately \$89 million and \$154 million of NSP-Minnesota's regulatory assets represented past expenditures not currently earning a return, respectively. This amount primarily includes PI EPU costs and recoverable purchased natural gas and electric energy costs.

12. Other Comprehensive Income

Changes in accumulated other comprehensive (loss) income, net of tax, for the years ended Dec. 31, 2015 and 2014 were as follows:

(Thousands of Dollars)	Year Ended Dec. 31, 2015			
	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	\$ (19,909)	\$ 105	\$ (1,010)	\$ (20,814)
Other comprehensive loss before reclassifications	(39)	—	(1,061)	(1,100)
Losses (gains) reclassified from net accumulated other comprehensive loss	858	—	(25)	833
Net current period other comprehensive income (loss)	819	—	(1,086)	(267)
Accumulated other comprehensive (loss) income at Sept. 30	\$ (19,090)	\$ 105	\$ (2,096)	\$ (21,081)

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(Thousands of Dollars)	Year Ended Dec. 31, 2014			
	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	\$ (20,609)	\$ 73	\$ (1,193)	\$ (21,729)
Other comprehensive (loss) income before reclassifications	(89)	32	161	104
Losses reclassified from net accumulated other comprehensive loss	789	—	22	811
Net current period other comprehensive income	700	32	183	915
Accumulated other comprehensive (loss) income at Sept. 30	\$ (19,909)	\$ 105	\$ (1,010)	\$ (20,814)

Reclassifications from accumulated other comprehensive (loss) income for the years ended Dec. 31, 2015 and 2014 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss			
	Year Ended Dec. 31, 2015		Year Ended Dec. 31, 2014	
(Gains) losses on cash flow hedges:				
Interest rate derivatives	\$ 1,385	(a)	\$ 1,387	(a)
Vehicle fuel derivatives	73	(b)	(30)	(b)
Total, pre-tax	1,458		1,357	
Tax benefit	(600)		(568)	
Total, net of tax	858		789	
Defined benefit pension and postretirement (gains) losses:				
Amortization of net loss	156	(c)	232	(c)
Prior service cost	(196)	(c)	(194)	(c)
Total, pre-tax	(40)		38	
Tax benefit	15		(16)	
Total, net of tax	(25)		22	
Total amounts reclassified, net of tax	\$ 833		\$ 811	

(a) Included in interest charges.

(b) Included in operating expenses.

(c) Included in the computation of net periodic pension and postretirement benefit costs. See Note 6 for details regarding these benefit plans.

13. Related Party Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy Inc., including NSP-Minnesota. The services are provided and billed to each subsidiary in accordance with service agreements executed by each subsidiary. NSP-Minnesota uses the services provided by Xcel Energy Services Inc. whenever possible. Costs are charged directly to the subsidiary and are allocated if they cannot be directly assigned.

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Xcel Energy Inc., NSP-Minnesota, PSCo and SPS have established a utility money pool arrangement. See Note 3 for further discussion.

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. The Interchange Agreement provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs.

The table below contains significant affiliate transactions among the companies and related parties including billings under the Interchange Agreement for the years ended Dec. 31:

(Thousands of Dollars)	2015	2014
Operating revenues:		
Electric	\$ 473,099	\$ 474,542
Gas	45	96
Operating expenses:		
Purchased power	70,504	68,703
Transmission expense	92,751	76,399
Other operating expenses — paid to Xcel Energy Services Inc	439,144	456,569
Interest expense	238	195
Interest income	94	12

Accounts receivable and payable with affiliates at Dec. 31 were:

(Thousands of Dollars)	2015		2014	
	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	\$ 18,268	\$ -	\$ 17,333	\$ -
PSCo	-	4,419	6,706	-
SPS	-	1,066	-	1,983
Other subsidiaries of Xcel Energy	25,972	54,300	10,609	48,561
	<u>\$ 44,240</u>	<u>\$ 59,785</u>	<u>\$ 34,648</u>	<u>\$ 50,544</u>

14. Supplementary Cash Flow Data

(Thousands of Dollars)	2015	2014
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	\$ (185,553)	\$ (182,081)
Cash (paid) received for income taxes, net	53,343	(33,424)
Supplemental disclosure of non-cash investing transactions:		
Property, plant and equipment additions in accounts payable	\$ 111,675	\$ 186,068

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15. Energy Storage Assets (FERC Order No. 784)

The FERC issued Order No. 784, "Third-Party Provision of Ancillary Services; Accounting and Financial Reporting For New Electric Storage Technologies" in July 2013. In February 2014, FERC issued guidance on complying with Order No. 784's new accounting and disclosure requirements until their Form 1 and Form 3 statements are revised to accommodate the changes. That guidance included a requirement to include disclosure information related to energy storage technologies in the notes to the financial statements. This information is presented below.

The Luverne Wind2Battery project is a one MW sodium sulfur battery storage facility that is operating in conjunction with the 11 MW Minwind wind power generating facility near Luverne, Minn. It is being used to store, control and dispatch energy when needed for supply or transmission stability purposes. The purpose of the facility is to provide NSP-Minnesota with experience and information that will allow NSP-Minnesota to assess and improve upon the viability of scaling up battery storage on the system as more wind power is added to meet the renewable policies.

Energy Plant Account

Energy storage assets are recorded in Account 348 in the amount of \$4,128,902 at Dec. 31, 2015. Due to FERC software limitations, these amounts are reported in Account 342.

Power Purchased Account

Energy storage-related purchased power costs are recorded in Account 555.1 in accordance with FERC Order No. 784 in the credit amount of \$30,910 for the year ended Dec. 31, 2015, reflecting true-up activity during the period. Due to FERC software limitations, these amounts are reported in Account 555.

Operation and Maintenance Expense Accounts

Energy storage-related operating expenses are recorded in Account 548.1 in accordance with FERC Order No. 784 in the amount of zero for the year ended Dec. 31, 2015. Due to FERC software limitations, these amounts are reported in Account 548.

Energy storage-related maintenance expenses are recorded in Account 553.1 in accordance with FERC Order No. 784 in the amount of \$109,218 for the year ended Dec. 31, 2015. Due to FERC software limitations, these amounts are reported in Account 553.

The following table presents NSP-Minnesota's Energy Storage Operations for small plants as of and for the year ended Dec. 31, 2015, as required by FERC Order No. 784:

Line no.	Name of Energy Storage Project	Functional Classification	Location of the Project	Project Cost	Operations (Excluding Fuel used in Storage Operations)	Maintenance	Cost of fuel used in storage operations	Account No. 555.1, Power Purchased for Storage Operations	Other Expenses
1	Luverne, Minn. Wind2Battery Project	Production	Luverne, Minn.	\$ 4,128,902	\$ —	\$ 109,218	\$ —	\$ (30,910)	\$ —

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Schedule Page: 122(a)(b) Line No.: 1 Column: g

Other cash flow hedging activity relates primarily to vehicle fuel and natural gas commodity derivatives.

This footnote applies to all of column g.

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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION					
Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.					
Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)		Electric (c)	
1	Utility Plant				
2	In Service				
3	Plant in Service (Classified)	15,978,647,164		14,250,869,874	
4	Property Under Capital Leases				
5	Plant Purchased or Sold				
6	Completed Construction not Classified	2,300,076,892		2,167,311,748	
7	Experimental Plant Unclassified				
8	Total (3 thru 7)	18,278,724,056		16,418,181,622	
9	Leased to Others				
10	Held for Future Use	19,135,157		19,135,157	
11	Construction Work in Progress	548,033,874		473,700,332	
12	Acquisition Adjustments	222,385		222,385	
13	Total Utility Plant (8 thru 12)	18,846,115,472		16,911,239,496	
14	Accum Prov for Depr, Amort, & Depl	6,940,949,706		6,064,926,004	
15	Net Utility Plant (13 less 14)	11,905,165,766		10,846,313,492	
16	Detail of Accum Prov for Depr, Amort & Depl				
17	In Service:				
18	Depreciation	6,607,632,927		5,967,889,247	
19	Amort & Depl of Producing Nat Gas Land/Land Right				
20	Amort of Underground Storage Land/Land Rights				
21	Amort of Other Utility Plant	333,094,394		96,814,372	
22	Total In Service (18 thru 21)	6,940,727,321		6,064,703,619	
23	Leased to Others				
24	Depreciation				
25	Amortization and Depletion				
26	Total Leased to Others (24 & 25)				
27	Held for Future Use				
28	Depreciation				
29	Amortization				
30	Total Held for Future Use (28 & 29)				
31	Abandonment of Leases (Natural Gas)				
32	Amort of Plant Acquisition Adj	222,385		222,385	
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,940,949,706		6,064,926,004	

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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION					
Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
1,179,376,176				548,401,114	3
					4
					5
69,031,715				63,733,429	6
					7
1,248,407,891				612,134,543	8
					9
					10
7,940,715				66,392,827	11
					12
1,256,348,606				678,527,370	13
568,373,610				307,650,092	14
687,974,996				370,877,278	15
					16
					17
563,794,370				75,949,310	18
					19
					20
4,579,240				231,700,782	21
568,373,610				307,650,092	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
568,373,610				307,650,092	33

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Schedule Page: 200 Line No.: 21 Column: c

The amortization of other utility plant within account 111 includes the following:

Intangible Plant	\$54,835,118
Nuclear Production	40,293,482
Hydro Production Conventional	916,338
Wind Production	769,434
Total	<u>\$96,814,372</u>

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)					
1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent. 2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.					
Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)		
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)				
2	Fabrication	11,047,276	26,945,786		
3	Nuclear Materials	171,635,310	61,611,022		
4	Allowance for Funds Used during Construction	8,304,773	9,809,073		
5	(Other Overhead Construction Costs, provide details in footnote)	200,095	62,810		
6	SUBTOTAL (Total 2 thru 5)	191,187,454			
7	Nuclear Fuel Materials and Assemblies				
8	In Stock (120.2)	365,168	142,557,238		
9	In Reactor (120.3)	527,866,883	142,654,799		
10	SUBTOTAL (Total 8 & 9)	528,232,051			
11	Spent Nuclear Fuel (120.4)	1,628,002,046	144,603,557		
12	Nuclear Fuel Under Capital Leases (120.6)				
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	1,957,229,917			
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	390,191,634			
15	Estimated net Salvage Value of Nuclear Materials in line 9				
16	Estimated net Salvage Value of Nuclear Materials in line 11				
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing				
18	Nuclear Materials held for Sale (157)				
19	Uranium				
20	Plutonium				
21	Other (provide details in footnote):				
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)				

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)					
Changes during Year				Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)				
					1
	21,018,486			16,974,576	2
	112,968,652			120,277,680	3
	6,774,042			11,339,804	4
	127,919			134,986	5
				148,727,046	6
					7
	142,922,406				8
	144,603,557			525,918,125	9
				525,918,125	10
				1,772,605,603	11
					12
-106,424,403				2,063,654,320	13
				383,596,454	14
					15
					16
					17
					18
					19
					20
					21
					22

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Schedule Page: 202 Line No.: 2 Column: e
Classified to Account 120.2 and 120.3
Schedule Page: 202 Line No.: 3 Column: e
Classified to Account 120.2 and 120.3
Schedule Page: 202 Line No.: 4 Column: e
Classified to Account 120.2 and 120.3
Schedule Page: 202 Line No.: 5 Column: e
Classified to Account 120.2 and 120.3
Schedule Page: 202 Line No.: 5 Column: f
Consists of Administration and General costs
Schedule Page: 202 Line No.: 8 Column: c
Consists of transfers from 120.1, and direct trailing charges to asset after in-service
Schedule Page: 202 Line No.: 8 Column: e
Transferred to Account 120.3
Schedule Page: 202 Line No.: 9 Column: e
Transferred to Account 120.4
Schedule Page: 202 Line No.: 15 Column: f
Not estimated because of disposal contracts with the Department of Energy resulting from the Nuclear Waste Disposal Act of 1982
Schedule Page: 202 Line No.: 16 Column: f
Not estimated because of disposal contracts with the Department of Energy resulting from the Nuclear Waste Disposal Act of 1982

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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)					
1. Report below the original cost of electric plant in service according to the prescribed accounts. 2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric. 3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year. 4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments. 5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts. 6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)					
Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)		
1	1. INTANGIBLE PLANT				
2	(301) Organization				
3	(302) Franchises and Consents	231,551,984	16,209,521		
4	(303) Miscellaneous Intangible Plant	86,441,639	32,984,416		
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	317,993,623	49,193,937		
6	2. PRODUCTION PLANT				
7	A. Steam Production Plant				
8	(310) Land and Land Rights	9,450,322			
9	(311) Structures and Improvements	319,780,994	5,727,348		
10	(312) Boiler Plant Equipment	1,435,350,821	49,944,530		
11	(313) Engines and Engine-Driven Generators				
12	(314) Turbogenerator Units	328,708,742	9,584,188		
13	(315) Accessory Electric Equipment	194,348,216	4,729,898		
14	(316) Misc. Power Plant Equipment	56,570,731	603,678		
15	(317) Asset Retirement Costs for Steam Production	42,120,252	4,113,651		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,386,330,078	74,703,293		
17	B. Nuclear Production Plant				
18	(320) Land and Land Rights	1,154,813			
19	(321) Structures and Improvements	480,877,219	35,210,149		
20	(322) Reactor Plant Equipment	1,509,994,609	40,297,099		
21	(323) Turbogenerator Units	541,957,270	87,240,268		
22	(324) Accessory Electric Equipment	442,495,100	35,391,882		
23	(325) Misc. Power Plant Equipment	161,782,424	37,050,731		
24	(326) Asset Retirement Costs for Nuclear Production	482,670,802			
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	3,620,932,237	235,190,129		
26	C. Hydraulic Production Plant				
27	(330) Land and Land Rights	1,693,076			
28	(331) Structures and Improvements	1,387,646			
29	(332) Reservoirs, Dams, and Waterways	8,782,564	1,808,265		
30	(333) Water Wheels, Turbines, and Generators	10,038,998			
31	(334) Accessory Electric Equipment	3,256,971			
32	(335) Misc. Power PLant Equipment	60,825			
33	(336) Roads, Railroads, and Bridges				
34	(337) Asset Retirement Costs for Hydraulic Production	132,561	127,667		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	25,352,641	1,935,932		
36	D. Other Production Plant				
37	(340) Land and Land Rights	18,914,458			
38	(341) Structures and Improvements	169,744,271	49,673,624		
39	(342) Fuel Holders, Products, and Accessories	79,744,192	982,098		
40	(343) Prime Movers				
41	(344) Generators	1,401,538,376	491,132,765		
42	(345) Accessory Electric Equipment	166,974,315	71,570,879		
43	(346) Misc. Power Plant Equipment	22,510,767	540,834		
44	(347) Asset Retirement Costs for Other Production	28,247,777	31,850,163		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,887,674,156	645,750,363		
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	7,920,289,112	957,579,717		

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)					
Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)		
47	3. TRANSMISSION PLANT				
48	(350) Land and Land Rights	137,821,651	11,569,955		
49	(352) Structures and Improvements	69,849,603	7,521,898		
50	(353) Station Equipment	1,049,108,090	77,907,715		
51	(354) Towers and Fixtures	118,649,977	556,200		
52	(355) Poles and Fixtures	951,252,184	288,595,548		
53	(356) Overhead Conductors and Devices	430,658,139	79,675,942		
54	(357) Underground Conduit	25,743,474	-95,755		
55	(358) Underground Conductors and Devices	30,649,629	314,271		
56	(359) Roads and Trails				
57	(359.1) Asset Retirement Costs for Transmission Plant	173,429			
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,813,906,176	466,045,774		
59	4. DISTRIBUTION PLANT				
60	(360) Land and Land Rights	15,747,013	715,329		
61	(361) Structures and Improvements	41,799,884	4,442,302		
62	(362) Station Equipment	566,843,905	19,779,509		
63	(363) Storage Battery Equipment				
64	(364) Poles, Towers, and Fixtures	353,472,705	19,069,407		
65	(365) Overhead Conductors and Devices	405,783,796	20,208,106		
66	(366) Underground Conduit	246,257,900	13,885,251		
67	(367) Underground Conductors and Devices	1,018,667,441	50,582,261		
68	(368) Line Transformers	411,222,994	23,579,658		
69	(369) Services	283,981,705	6,094,896		
70	(370) Meters	109,504,494	5,531,960		
71	(371) Installations on Customer Premises	22,705,174			
72	(372) Leased Property on Customer Premises				
73	(373) Street Lighting and Signal Systems	59,188,382	2,255,911		
74	(374) Asset Retirement Costs for Distribution Plant	3,574,449	195,820		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,538,749,842	166,340,410		
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT				
77	(380) Land and Land Rights				
78	(381) Structures and Improvements				
79	(382) Computer Hardware				
80	(383) Computer Software				
81	(384) Communication Equipment				
82	(385) Miscellaneous Regional Transmission and Market Operation Plant				
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper				
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)				
85	6. GENERAL PLANT				
86	(389) Land and Land Rights	4,438,920			
87	(390) Structures and Improvements	59,093,289	5,736,559		
88	(391) Office Furniture and Equipment	45,283,514	4,869,289		
89	(392) Transportation Equipment	106,522,761	38,670,823		
90	(393) Stores Equipment	1,781,931			
91	(394) Tools, Shop and Garage Equipment	71,171,114	9,237,315		
92	(395) Laboratory Equipment	3,234,096	588,119		
93	(396) Power Operated Equipment	33,015,777	9,128,824		
94	(397) Communication Equipment	43,187,781	6,115,937		
95	(398) Miscellaneous Equipment	2,872,141	6,567		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	370,601,324	74,353,433		
97	(399) Other Tangible Property				
98	(399.1) Asset Retirement Costs for General Plant				
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	370,601,324	74,353,433		
100	TOTAL (Accounts 101 and 106)	14,961,540,077	1,713,513,271		
101	(102) Electric Plant Purchased (See Instr. 8)				
102	(Less) (102) Electric Plant Sold (See Instr. 8)				
103	(103) Experimental Plant Unclassified				
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	14,961,540,077	1,713,513,271		

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016		Year/Period of Report End of 2015/Q4	
ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)							
Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.		
					47		
1,148,545		295	148,243,356		48		
70,652		1,683,373	78,984,222		49		
3,507,159		20,624,754	1,144,133,400		50		
10,264		-689,542	118,506,371		51		
4,946,544		689,542	1,235,590,730		52		
2,860,800			507,473,281		53		
			25,647,719		54		
12,708			30,951,192		55		
					56		
			173,429		57		
12,556,672		22,308,422	3,289,703,700		58		
					59		
		-295	16,462,047		60		
138,814		-1,224	46,102,148		61		
3,966,154		-51,741	582,605,519		62		
					63		
1,468,428			371,073,684		64		
7,110,568			418,881,334		65		
407,021		1,729,688	261,465,818		66		
4,231,060			1,065,018,642		67		
6,677,158			428,125,494		68		
221,438			289,855,163		69		
4,471,117			110,565,337		70		
			22,705,174		71		
					72		
653,197			60,791,096		73		
			3,770,269		74		
29,344,955		1,676,428	3,677,421,725		75		
					76		
					77		
					78		
					79		
					80		
					81		
					82		
					83		
					84		
					85		
			4,438,920		86		
1,474,613			63,355,235		87		
702,058			49,450,745		88		
104,329			145,089,255		89		
57,769			1,724,162		90		
3,325,572			77,082,857		91		
283,177			3,539,038		92		
52,719			42,091,882		93		
370,646		30,017	48,963,089		94		
11,893			2,866,815		95		
6,382,776		30,017	438,601,998		96		
					97		
					98		
6,382,776		30,017	438,601,998		99		
164,997,545	-115,913,046	24,038,865	16,418,181,622		100		
					101		
					102		
					103		
164,997,545	-115,913,046	24,038,865	16,418,181,622		104		

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 204 Line No.: 5 Column: g

This footnote also applies to the following pages, lines and columns:

Schedule Page: 205 Line No: 46 Column: g
Schedule Page: 207 Line No: 58 Column: g
Schedule Page: 207 Line No: 75 Column: g
Schedule Page: 207 Line No: 99 Column: g

Electric Plant in Service (Accounts 101, 102, 103 and 106). The Form 1 reports total intangible plant (line 5), production plant (line 46), transmission plant (line 58), distribution plant (line 75) and general plant (line 99) at the beginning of the year and at the end of the year. The Company uses a 13-month average calculation for the plant in service balances included in the formula. Production plant and distribution plant balances are included in the development of the gross plant and net plant allocators that are used to allocate cost to the transmission function in the formula.

Schedule Page: 204 Line No.: 39 Column: g

Account 342 Fuel Holders, Producers, and Accessories	\$84,291,690
Account 348 Energy Storage, Equipment - Production	4,128,902
	<u>\$88,420,592</u>

Schedule Page: 204 Line No.: 58 Column: c

Transmission Serving Production

	Beginning Balance	Additions	Retirement s	Adjustmen ts	Transfers	Ending Balance
Account 350 - Land & Land Rights	157,969	0	0	0	0	157,969
Account 352 - Structures & Improvements	10,460,207	0	0	0	0	10,460,207
Account 353 - Station Equipment	53,716,468	0	(91,452)	0	0	53,625,016
Account 354 - Towers & Fixtures	4,916,560	219,856	0	0	0	5,136,416
Account 355 - Poles & Fixtures	3,072,288	2,147,770	(980,704)	0	0	4,239,354
Account 356 - Overhead Conductors & Devices	847,968	0	(418,313)	0	0	429,655

Schedule Page: 204 Line No.: 75 Column: c

Distribution Serving Production

	Beginning Balance	Additions	Retirement s	Adjustmen ts	Transfers	Ending Balance
Account 361 - Structures & Improvements	838,281	0	0	0	0	838,281
Account 362 - Station Equipment	2,692,338	0	0	0	0	2,692,338

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
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10					
11					
12					
13					
14					
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41					
42					
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44					
45					
46					
47	TOTAL				

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)					
1. Report separately each property held for future use at end of the year having an original cost of \$250,000 or more. Group other items of property held for future use.					
2. For property having an original cost of \$250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.					
Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)	
1	Land and Rights:				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Other Property:				
22					
23	Falls Dist Substation Comm Equip, South Dakota	2015	2016	63,644	
24					
25	Falls Substation Dist, South Dakota	2015	2016	9,137,790	
26					
27	Falls Substation Trans, South Dakota	2015	2016	3,989,257	
28					
29	Dist Underground Conduit, South Dakota	2014	2016	160,973	
30					
31	Nuclear Dry Fuel Canisters, Monticello Nuc Gen Plant	2014	2018	5,783,493	
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	Footnote from Page 106b				
47	Total				19,135,157

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 214 Line No.: 46 Column: d

Electric Plant Held for Future Use (Account 105). The Form 1 reports the plant held for future use balances at the end of the year. NSP-Minnesota uses only the transmission-related land and land rights plant held for future use in the formula. NSP-Minnesota uses a 13-month average calculation of these plant balances included in the formula rate.

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)					
1. Report below descriptions and balances at end of year of projects in process of construction (107) 2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts) 3. Minor projects (5% of the Balance End of the Year for Account 107 or \$1,000,000, whichever is less) may be grouped.					
Line No.	Description of Project (a)				Construction work in progress - Electric (Account 107) (b)
1	CRT0C Courtenay Wind Farm Construct				97,808,647
2	CAPX Hampton-N.Rochester 345kV				42,906,637
3	PI-9 TN-40 Casks(39-47)				32,168,107
4	MNGP 2013 Dry Fuel Storge Load				15,721,805
5	PI-NFPA 805 Fire Model				12,764,406
6	Prairie 3rd 230/115 kv transfo				12,245,285
7	PI U1 Generator Replacemnt LCM				12,194,894
8	Dynamic EMS Environment Phase				11,830,615
9	BDS0C Black Dog U6 Simple Cycl				11,464,447
10	CapX N. Rochester-Chester line				11,375,881
11	BSSB-345kV Non Shared Line				10,734,036
12	PI U2 HDTP Speed Control Upgr				7,844,448
13	MNGP Security Physical Upgrade				7,393,998
14	MNGP EDG Tornado Missile Prote				6,672,407
15	PI Emerg Resp Equipment FLEX				6,533,554
16	Bluff Creek 115kV Expansion Su				6,444,689
17	BDS0C 316b Screenhouse				5,328,249
18	PI Reactor Coolant Pump Rebuil				5,198,628
19	MNGP DAS & PPCS Rplc				4,991,621
20	MNGP DAS & PPCS Rplc				4,756,453
21	SHC3C Motor Control Sys PLC Re				4,308,798
22	MNGP Cyber Security 08-09				3,279,614
23	Purch NS T&D Network Equip MN				3,247,551
24	NSPM Physical Security Pre Con				3,150,363
25	MNGP Calc Reconstitution Proje				3,136,806
26	Install Falls Sub UG Feeders				2,788,296
27	Adams-Replace #10 Reactor Sub				2,658,262
28	ADMS SW MN				2,598,502
29	PI NSSS/BOP Annunciator Repl				2,473,738
30	GSL to PKL Line Permit Pre Con				2,422,664
31	Line 0795 rebuild for G858/H07				2,410,852
32	PI NFPA 72E Fire Detect Instal				2,309,452
33	MNGP 2018 Dry Fuel Storage Loa				2,261,934
34	Install Renner substation				2,193,943
35	Hugo Sub Simulator Phase 1				1,909,953
36	Instl second bank Fiesta City				1,878,040
37	Purch Sub Frame Relay Equip MN				1,836,365
38	CAPX BRK BTF STF HCL0230 Land				1,724,192
39	Add Eastwood TR3				1,716,326
40	PI Sfgds CL Pump Redesign				1,660,567
41	CAPX BRK BTF STF CHX1360 Land				1,657,985
42	SHC2C U2 Turbine EHC Ctrls Rep				1,561,763
43	TOTAL				473,700,332

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of <u>2015/Q4</u>
CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)					
1. Report below descriptions and balances at end of year of projects in process of construction (107) 2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts) 3. Minor projects (5% of the Balance End of the Year for Account 107 or \$1,000,000, whichever is less) may be grouped.					
Line No.	Description of Project (a)				Construction work in progress - Electric (Account 107) (b)
1	MN Frame Relay Comm				1,475,480
2	MNGP HAYS 02 Monitor Rplc				1,430,931
3	Remove network in Sioux Falls				1,421,731
4	RIV9C-U9 HGP Inspection No 1				1,415,533
5	T: Rebuild head end of WSG362 3.6mi				1,378,354
6	PI Foxboro Proc Controls Repl				1,323,041
7	NSPM-Accelerated URD Cable Rep				1,320,810
8	PI 1R Transformer Replacement				1,314,228
9	PI U1 Turb/Gen Vibration Monit				1,301,997
10	Kohlman Lake 30 MVAR Inductor				1,298,749
11	Maple Grv-Ug Conversion/Rebuil				1,267,855
12	PI NFPA 805 -05 Incipient Det				1,256,819
13	MNGP Rplc NON 1E Inverter, Y-9				1,211,120
14	NSPM 0729 Cliff Ave Reloc ROW				1,172,683
15	PI 2015 Misc Minor Improvement				1,101,468
16	Substation Transformer Replace				1,097,718
17	PI 11/21 Turb Bldg Crane Upgr				1,072,823
18	Minnesota inspect/replace pole				1,040,741
19					
20	Minor Projects				71,233,478
21	Footnote from Page 106b				
22					
23					
24					
25					
26					
27					
28					
29					
30					
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32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43	TOTAL				473,700,332

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 216.1 Line No.: 21 Column: a

Construction Work in Progress (Account 107). The Form 1 reports the total Company construction work in progress (CWIP) balances at the end of the year. The Company uses a 13-month average calculation for the specific CWIP project balances included in the formula. The Company can only include CWIP in the formula related to the following specific projects, the balances of which could be a component of the amounts reported on page 216: the three projects in Group 1 of the CapX2020 Project - Twin Cities-Brookings County, Twin Cities-Fargo, Twin Cities-LaCrosse.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year					
Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	5,689,630,022	5,689,630,022		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	439,872,755	439,872,755		
4	(403.1) Depreciation Expense for Asset Retirement Costs	9,649,598	9,649,598		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	11,750,154	11,750,154		
7	Other Clearing Accounts	161,246	161,246		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	461,433,753	461,433,753		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	155,958,334	155,958,334		
13	Cost of Removal	25,032,193	25,032,193		
14	Salvage (Credit)	4,839,520	4,839,520		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	176,151,007	176,151,007		
16	Other Debit or Cr. Items (Describe, details in footnote):	-6,589,660	-6,589,660		
17					
18	Book Cost or Asset Retirement Costs Retired	-433,861	-433,861		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	5,967,889,247	5,967,889,247		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	1,305,549,246	1,305,549,246		
21	Nuclear Production	1,607,863,454	1,607,863,454		
22	Hydraulic Production-Conventional	9,556,643	9,556,643		
23	Hydraulic Production-Pumped Storage				
24	Other Production	625,133,975	625,133,975		
25	Transmission	763,652,172	763,652,172		
26	Distribution	1,489,876,107	1,489,876,107		
27	Regional Transmission and Market Operation				
28	General	166,257,650	166,257,650		
29	TOTAL (Enter Total of lines 20 thru 28)	5,967,889,247	5,967,889,247		

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 219 Line No.: 16 Column: c

Net change in RWIP	\$ (6,649,334)
Net Transfers	(116)
Gain/Loss	59,816
Other	(26)
Total	<u>\$ (6,589,660)</u>

Schedule Page: 219 Line No.: 20 Column: c

Schedule Page: 219

Line No.: 20-26, 28

Column: c

Accumulated Provision for Depreciation (Account 108). The Form 1 reports the accumulated provision for depreciation balances at the end of year. The Company uses a 13-month average calculation for the accumulated provision for depreciation balances included in the formula. Production and distribution accumulated provision for depreciation balances are included in developing the net plant allocator used to allocate costs to the transmission function in the formula.

Schedule Page: 219 Line No.: 25 Column: c

Transmission Serving Production	\$ 31,158,437

Schedule Page: 219 Line No.: 26 Column: c

Distribution Serving Production	\$ 1,972,024

Schedule Page: 219 Line No.: 29 Column: b

	"Non-Legal" ARO Balances
Steam Plant	<u>\$ 73,252,347</u>
Nuclear Plant	(61,987,074)
Hydraulic Production-Conventional	1,335,555
Other Production	11,561,214
Transmission	87,773,542
Distribution	232,674,614
General	(863,350)
Total	<u>\$ 343,746,848</u>

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.

2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)

(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.

(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.

3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	UNITED POWER & LAND CO.			
2	Common Stock-par \$100 per share			4,020,000
3	Additional Paid in Capital			299,792
4	Undistributed earnings (loss) since acquisition			-3,179,300
5	SUBTOTAL			1,140,492
6				
7	NSP NUCLEAR CO.			
8	Contributed Capital			972,613
9	Undistributed earnings (loss) since acquisition			551,567
10	SUBTOTAL			1,524,180
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	5,282,964	TOTAL	2,664,672

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		4,020,000		2
	-27	299,765		3
-99,344	1	-3,278,643		4
-99,344	-26	1,041,122		5
				6
				7
	-9,415	963,198		8
-2,827		548,740		9
-2,827	-9,415	1,511,938		10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
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				29
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				31
				32
				33
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				37
				38
				39
				40
				41
-102,171	-9,441	2,553,060		42

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 224 Line No.: 3 Column: f
Annual allocation of unitary tax benefit/detriment

Schedule Page: 224 Line No.: 4 Column: f
rounding

Schedule Page: 224 Line No.: 8 Column: f
Annual allocation of unitary tax benefit/detriment

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of <u>2015/Q4</u>
MATERIALS AND SUPPLIES					
1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material. 2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.					
Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)	
1	Fuel Stock (Account 151)	80,824,146	107,654,333	Electric	
2	Fuel Stock Expenses Undistributed (Account 152)				
3	Residuals and Extracted Products (Account 153)				
4	Plant Materials and Operating Supplies (Account 154)				
5	Assigned to - Construction (Estimated)	28,921,345	19,105,622	Electric & Gas	
6	Assigned to - Operations and Maintenance				
7	Production Plant (Estimated)	125,098,335	179,817,532	Electric	
8	Transmission Plant (Estimated)	733,599	309,594	Electric	
9	Distribution Plant (Estimated)	3,898,009	3,218,545	Electric & Gas	
10	Regional Transmission and Market Operation Plant (Estimated)				
11	Assigned to - Other (provide details in footnote)	-2,571,848	-2,308,923		
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	156,079,440	200,142,370		
13	Merchandise (Account 155)	1,286,223	738,863		
14	Other Materials and Supplies (Account 156)				
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)				
16	Stores Expense Undistributed (Account 163)				
17					
18	note re: page 106 formula rates				
19					
20	TOTAL Materials and Supplies (Per Balance Sheet)	238,189,809	308,535,566		

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 227 Line No.: 11 Column: b

Includes a credit of \$2,975,620 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a debit of \$403,772 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.

Schedule Page: 227 Line No.: 11 Column: c

Includes a credit of \$2,992,149 for inventory allocated to Southern Minnesota municipal Power Agency (41 percent owners of Sherco 3) and a debit of \$683,226 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.

Schedule Page: 227 Line No.: 18 Column: a

Materials & Supplies (Accounts 154 and 163). The Form 1 reports the materials and supplies balances at the beginning and end of the year. The Company uses the average of the beginning and end of the year materials and supplies balances in the formula rate (see page 106).

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.

2. Report all acquisitions of allowances at cost.

3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.

4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).

5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		2016	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	579,832.00		63,941.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	22,196.00		22,196.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	15,586.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	586,442.00		86,137.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	925.00		925.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	925.00			
40	Balance-End of Year			925.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	925.00	103		
45	Gains		103		
46	Losses				

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016		Year/Period of Report End of 2015/Q4		
Allowances (Accounts 158.1 and 158.2) (Continued)								
6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances. 7. Report on Lines 8-14 the names of vendors/transferrors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts). 8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies. 9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers. 10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.								
2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
63,941.00		63,941.00		1,598,525.00		2,370,180.00		1
								2
								3
22,196.00		22,196.00		44,392.00		133,176.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						15,586.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
86,137.00		86,137.00		1,642,917.00		2,487,770.00		28
								29
								30
								31
								32
								33
								34
								35
925.00		925.00		44,398.00		48,098.00		36
				1,850.00		1,850.00		37
								38
				926.00		1,851.00		39
925.00		925.00		45,322.00		48,097.00		40
								41
								42
								43
				926.00	28	1,851.00	131	44
					28		131	45
								46

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Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 228 Line No.: 44 Column: m

Proceeds from SO2 allowance sales from plants owned by NSP-Minnesota. This amount will not agree to Account 411.8 on the Income Statement (see page 114-117) due to proceeds from the sale of Renewable Energy Credits, sharing of the proceeds through the FERC-approved Interchange Agreement, and the specific regulatory treatment prescribed by the Minnesota, North Dakota, and South Dakota state regulatory commissions.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

Allowances (Accounts 158.1 and 158.2)

- Report below the particulars (details) called for concerning allowances.
- Report all acquisitions of allowances at cost.
- Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
- Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
- Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		2016	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	14,627.00		14,627.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	10,743.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	3,884.00		14,627.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.

7. Report on Lines 8-14 the names of vendors/transferrors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).

8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.

9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.

10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
								2
								3
14,627.00		14,627.00		29,254.00		87,762.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						10,743.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
14,627.00		14,627.00		29,254.00		77,019.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016		Year/Period of Report End of <u>2015/Q4</u>	
EXTRAORDINARY PROPERTY LOSSES (Account 182.1)							
Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)	
				Account Charged (d)	Amount (e)		
1	None						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20	TOTAL						

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4	
UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)						
Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	Prairie Island	78,884,915		see note	2,856,973	68,027,230
22	Extended Power Uprate project					
23	MPUC Docket No.					
24	E002/CN-08-509					
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	78,884,915			2,856,973	68,027,230

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 230 Line No.: 21 Column: a

In 2009, the Minnesota Public Utilities Commission (MPUC) granted NSP-Minnesota a Certificate of Need for an Extended Power Uprate (EPU) project at the Prairie Island (PI) nuclear generating plant. The total estimated cost of the EPU was \$294 million, of which approximately \$78.9 million had been incurred through 2012, including AFUDC of approximately \$12.8 million. Subsequently, NSP-Minnesota made a change of circumstances filing notifying the MPUC that there were changes in the size, timing and cost estimates for this project, revisions to economic and project design analysis and changes due to the estimated impact of revised scheduled outages. The information indicated reductions to the estimated benefit of the uprate project. As a result, NSP-Minnesota concluded that further investment in this project would not benefit customers. In February 2013, the MPUC issued an order terminating the CON for the PI EPU project.

In its 2014 Minnesota retail electric rate case under MPUC Docket 13-868, NSP-Minnesota received recovery of approximately \$59 million of deferred costs plus a debt-only return of 2.24 percent, to be recovered over 20.3 years.

On Nov. 19, 2015, the FERC approved a request under FERC Docket ER15-698 to allocate a portion of the amortization and debt-only return to NSP-Wisconsin under the Interchange Agreement. Approximately \$12 million will be amortized, beginning on Jan. 1, 2016 and continuing for 18.3 years.

NSP-Minnesota intends to seek recovery of North Dakota and South Dakota jurisdictional amounts in future rate proceedings.

Schedule Page: 230 Line No.: 21 Column: b

Transfers from Account No. 107 during 2012	\$ 77,690,096
Transfers from Account No. 107 during 2013	1,194,819
	<u>\$ 78,884,915</u>

Schedule Page: 230 Line No.: 21 Column: e

Account No. 426.5 - accretion during 2015	\$ (2,920,657)
Account No. 407 - amortization during 2015	5,777,630
	<u>\$ 2,856,973</u>

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of <u>2015/Q4</u>
Transmission Service and Generation Interconnection Study Costs					
1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies. 2. List each study separately. 3. In column (a) provide the name of the study. 4. In column (b) report the cost incurred to perform the study at the end of period. 5. In column (c) report the account charged with the cost of the study. 6. In column (d) report the amounts received for reimbursement of the study costs at end of period. 7. In column (e) report the account credited with the reimbursement received for performing the study.					
Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	Facilities Study G826 Lakefield	(113)	561.7	1,627	143.0
23	Adams Sub J026 Facilities Study	1,729	561.7	40,247	143.0
24	F096 Network Upgrades Facilities	4,408	561.7	8,766	143.0
25	G261 Facility Study	8,483	561.7	8,483	143.0
26	J262-J263 Facility Study	10,467	561.7	10,467	143.0
27	J288 Facilities Study	14,155	561.7		
28	J309 Facility Study	14,456	561.7		
29	J303 Facility Study	18,099	561.7		
30	J385 Facility Study	111,137	561.7		
31	J400 Facility Study	39,305	561.7		
32	C019 Facility Study	18,092	561.7		
33	J426 Facility Study	34,585	561.7		
34	J330 Facility Study	18,635	561.7		
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 231 Line No.: 2 Column: b

The values reported on this page represent the actual costs incurred or reimbursements received in the reporting period. As a result, cost and reimbursements for each study may be reported in different reporting periods.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Conservation and Energy Management Program Costs		174,206,245	Various	165,057,957	9,148,288
2	Minnesota Electric					
3	- MN Docket E-002/M-15-320					
4	- Generally amortized over 12 month					
5	period following the expenditure					
6						
7	Conservation and Energy Management Program Costs		24,768,200	Various	24,286,969	481,231
8	Minnesota Natural Gas					
9	- MN Docket G-002/M-15-321					
10	- Generally amortized over 12 month					
11	period following the expenditure					
12						
13	Conservation and Energy Management Program Costs	84,243		908	42,121	42,122
14	North Dakota Electric					
15	- ND Docket PU-12-813					
16	- Amortized over 4 years (01/2013-12/2016)					
17						
18	Conservation and Energy Management Program Costs	27,895	844,973	Various	834,815	38,053
19	South Dakota Electric					
20	- SD Docket EL-15-015					
21	- Generally amortized over 12 month					
22	period following the expenditure					
23						
24	Net of Tax AFUDC in Plant Adjustments	200,524,917	3,563,693			204,088,610
25						
26	South Dakota Ratemaking Differences	4,150,250	116,000	419.1	450,000	3,816,250
27	- SD Docket F-3382					
28	- SD Docket F-3422					
29						
30	Renewable Development Fund Rider	42,645,825	25,600,000	Various	19,327,281	48,918,544
31	- MN Docket E-002/M-14-814					
32						
33	Asset Retirement Recovery	1,731,064,534	120,799,177			1,851,863,711
34						
35	Minnesota Electric State Energy Policy Rider	213,942		407.3	213,942	
36	- MN Docket E-002/M-13-959					
37						
38	Minnesota Gas State Energy Policy Rider	85,167	979,230	407.3	1,064,397	
39	- MN Docket G-002/M-15-194					
40						
41	Minnesota Transmission Cost Recovery Rider	9,852,120		407.3	1,884,453	7,967,667
42	- MN Docket E-002/M-13-868					
43						
44	TOTAL	2,828,379,652	650,673,016		421,005,226	3,058,047,442

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Power Contract Valuation Adjustment	139,632,302	8,298,178	244	13,827,209	134,103,271
2						
3	Costs to Relocate Facilities Underground	777,131	23,637	142	561,840	238,928
4	- MN Docket E-002/M-99-799					
5						
6	Private Fuel Storage	280,074		407.3	109,819	170,255
7	- Amortized over 4-6 years					
8	- ND Docket PU-12-813 (Amortized 01/2013-12/2016)					
9	- SD Docket EL12-046 (Amortized 01/2010-01/2016)					
10						
11	Deferred Electric Commodity Costs		4,509,758	Various	4,155,433	354,325
12						
13	Mankato/Cannon Falls Lease Normalization	40,312,448	1,223,570			41,536,018
14						
15	Minnesota Renewable Energy Standard Rider		8,166,398	Various	6,598,552	1,567,846
16	- MN Docket E-002/M-14-733					
17						
18	Deferred Nuclear Outage Costs	82,244,324	92,743,272	Various	78,529,892	96,457,704
19	- Generally amortized over 23-24 months					
20	- MN Docket E-002/M-07-1489					
21	- ND Docket PU-07-774					
22	- SD Docket EL-07-035					
23						
24	Benefit Cost Recovery Deficit	376,201,821	90,812,793	Various	88,434,970	378,579,644
25						
26	Unrealized Gains on Decommissioning Trust		4,544,083	Various	4,544,083	
27	Investments					
28						
29	South Dakota Transmission Cost Recovery Rider		388,092	Various	291,045	97,047
30	-SD Docket EL-14-080					
31						
32	Transmission Formula-Att O True-up	1,499,941	7,633,135			9,133,076
33						
34	Electric Low Income Discount Program	1,993,384		254	1,993,384	
35	- MN Docket E-002/M-04-1956					
36	- MN Docket E-002/M-10-854					
37	- MN Docket E-002/GR-12-961					
38						
39	Windsor Tracker	158,335	54,569			212,904
40	- MN Docket E-002/M-01-1479					
41	- MN Docket E-002/GR-12-961					
42						
43						
44	TOTAL	2,828,379,652	650,673,016		421,005,226	3,058,047,442

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	South Dakota Infrastructure Rider		283,050	254	283,050	
2	-SD Docket EL-15-038					
3						
4	Sherco 3 Depreciation Deferral	10,062,593		407.3	466,162	9,596,431
5	-MN Docket E-002/GR-13-868					
6	- Amortized over 21 years (01/2014-12/2035)					
7						
8	Theoretical Depreciation Reserve Surplus	161,608,911	75,810,719			237,419,630
9	-MN Docket E-002/GR-12-961					
10	-MN Docket E-002/GR-13-868					
11						
12	North Dakota Transmission Cost Recovery Rider	2,137,036		407.3	1,419,327	717,709
13	- ND Docket PU-14-644					
14						
15	Gas Utility Infrastructure Cost Rider	22,822,459	9,719	Various	5,922,563	16,909,615
16	- MN Docket G-002/M-14-336					
17	- Amortized over 5 years (01/2015-12/2019)					
18						
19	North Dakota Renewable Energy Rider		225,175			225,175
20	- ND Docket PU-15-683					
21						
22	Minnesota Electric Vehicle Tariff		23,418			23,418
23	- MN Docket E-002/M-15-111					
24						
25	North Dakota Environmental Cleanup		4,141,258			4,141,258
26						
27	South Dakota Property Tax Collected in the		904,674	408.1	705,962	198,712
28	Fuel Clause Adjustment					
29	- SD Docket EL 14-058					
30						
31						
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40						
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42						
43						
44	TOTAL	2,828,379,652	650,673,016		421,005,226	3,058,047,442

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 1 Column: d

Accounts charged:

254	\$56,291,007
431	56,562
456	44,675,589
908	64,034,799
Total	<u>\$165,057,957</u>

Schedule Page: 232 Line No.: 7 Column: d

Accounts charged:

254	\$12,398,882
421	34,896
495	4,895,514
908	6,957,677
Total	<u>\$24,286,969</u>

Schedule Page: 232 Line No.: 18 Column: d

Accounts charged:

421	\$1,753
431	7,035
908	826,027
Total	<u>\$834,815</u>

Schedule Page: 232 Line No.: 30 Column: d

Accounts charged:

254	\$2,048,132
407.3	17,279,149
Total	<u>\$19,327,281</u>

Schedule Page: 232.1 Line No.: 11 Column: d

Accounts charged:

254	\$2,356,473
456	1,798,960
Total	<u>\$4,155,433</u>

Schedule Page: 232.1 Line No.: 15 Column: d

Accounts charged:

254	\$5,071,200
557	1,527,352
Total	<u>\$6,598,552</u>

Schedule Page: 232.1 Line No.: 18 Column: c

Accounts charged:

517	\$8,426,942
519	1,249,090
520	10,672,503
523	473,854
524	4,000,568
528	4,697,529
529	119,798
530	32,752,544
531	4,638,495
532	25,711,949
Total	<u>\$92,743,272</u>

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 232.1 Line No.: 18 Column: d

Accounts charged:

517	\$6,841,578
519	1,123,981
520	9,595,449
523	214,646
524	5,372,197
528	4,858,657
529	117,724
530	20,684,529
531	11,515,000
532	18,206,131
Total	<u>\$78,529,892</u>

Schedule Page: 232.1 Line No.: 24 Column: d

Accounts charged:

184	\$34,169,651
219	\$5,864,879
228.3	48,400,440
Total	<u>\$88,434,970</u>

Schedule Page: 232.1 Line No.: 26 Column: d

Accounts charged:

128	\$2,852,931
282	1,691,152
Total	<u>\$4,544,083</u>

Schedule Page: 232.1 Line No.: 29 Column: d

Accounts charged:

254	\$218,542
431	72,503
Total	<u>\$291,045</u>

Schedule Page: 232.2 Line No.: 15 Column: d

Accounts charged:

407.3	\$1,306,717
856	652,840
863	229,919
870	528
874	3,552,940
880	123,263
887	39,911
892	3,776
893	12,669
Total	<u>\$5,922,563</u>

MISCELLANEOUS DEFERRED DEBITS (Account 186)

- Report below the particulars (details) called for concerning miscellaneous deferred debits.
- For any deferred debit being amortized, show period of amortization in column (a)
- Minor item (1% of the Balance at End of Year for Account 186 or amounts less than \$100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	IPP Power Contract Billing	893,709	14,209	555	33,320	874,598
2	Adjustments					
3						
4	Conservation and Energy	79,213,019	45,794,683	182.3	82,836,794	42,170,908
5	Management Program Costs					
6	Minnesota Electric Incentive					
7	(Docket E-002/M-15-320)					
8						
9	Conservation and Energy	11,138,930	5,604,865	182.3	11,198,129	5,545,666
10	Management Program Costs					
11	Minnesota Gas Incentive					
12	(Docket G-002/M-15-321)					
13						
14	Federal and State Income	19,508	144,630	253	164,138	
15	Taxes Receivable					
16						
17	Federal and State Income	2,573,701	474,518			3,048,219
18	Tax Interest Receivable					
19						
20	Debt Issuance Costs	1,091	2,578,521	181	2,578,912	700
21						
22	2014 Minnesota Electric Retail	1,357,000		928	1,357,000	
23	Rate Case					
24	- Amortized through Dec. 2015					
25	(Docket E-002/GR-13-868)					
26						
27	2016 Minnesota Electric Retail		1,386,934			1,386,934
28	Rate Case					
29	(Docket E-002/GR-15-826)					
30						
31	Monticello Prudence Review	475,000		928	475,000	
32	- Amortized through Dec. 2015					
33	(Docket E-002/GR-13-868)					
34						
35	Future Minnesota Gas Retail	39,810		928	39,810	
36	Rate Case					
37						
38	2010 North Dakota Electric	106,211		928	53,106	53,105
39	Retail Rate Case					
40	- Amortized through Dec. 2016					
41	(Docket PU-10-657)					
42	(Docket PU-12-813)					
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	96,612,407				54,088,311

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

MISCELLANEOUS DEFERRED DEBITS (Account 186)

- Report below the particulars (details) called for concerning miscellaneous deferred debits.
- For any deferred debit being amortized, show period of amortization in column (a)
- Minor item (1% of the Balance at End of Year for Account 186 or amounts less than \$100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	2013 North Dakota Electric	309,000		928	154,500	154,500
2	Retail Rate Case					
3	-Amortized through Dec. 2016					
4	(Docket PU-12-813)					
5						
6	North Dakota Electric	168,537	333,589			502,126
7	Retail Rate Case - Settlement					
8	(Docket PU-12-813)					
9						
10	2014 South Dakota Electric	316,891	40,688	928	119,193	238,386
11	Retail Rate Case					
12	(Docket EL14-058)					
13						
14	Future South Dakota Electric		113,169			113,169
15	Retail Rate Case					
16	(Docket EL 14-058)					
17						
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	96,612,407				54,088,311

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 234 Line No.: 2 Column: b

	Balance at Beginning of Year	Balance at End of Year
Electric Plant Related Only:		
Decommissioning	\$ 57,101,144	\$ -
Electric Distribution Plant	71,034,859	76,048,313
Electric General Plant	124,435	447,563
Electric Intangible Plant	7,269,417	6,114,820
Electric Nuclear Fuel	22,203,287	23,492,096
Electric Nuclear Production Plant	45,420,315	89,454,340
Electric Production Plant	46,779,890	45,505,619
Electric Transmission Plant	37,877,666	39,159,422
Electric Transmission - Production Plant	548,442	573,614
Common (Allocation to Electric)	784,070	628,168
Regulatory Difference - Effect of Rate Changes	213,386	(539,634)
Regulatory Difference - Investment Tax Credit Gross-Up	19,151,230	18,019,282
Total Electric Plant Related Only	<u>\$308,508,141</u>	<u>\$298,903,603</u>

Schedule Page: 234 Line No.: 8 Column: b

	Balance at Beginning of Year	Balance at End of Year
Electric:		
Avoided Tax Interest	\$140,274,160	\$140,545,071
Bad Debts	8,493,866	7,692,393
Capital Loss Carryforward	870,889	-
Customer Advances	427,047	389,493
Deferred Connection Fees	63,392,050	67,748,255
Deferred Revenue	1,423,256	1,239,715
Economic Development Securities - Write-Off	227,380	227,629
Electric Vehicle Credit	6,932	6,944
Employee Incentive Plans	8,006,682	6,927,682
Employee Retention	438,904	4,316
Employee Stock Ownership Program Dividends	5,745,837	5,983,639
End of Life Nuclear Fuel Amortization	22,203,287	23,492,096
Environmental Remediation	106,103	77,516
Federal Net Operating Loss	193,117,192	346,606,795
Fuel Tax Credit - Income Addback	8,002	23,324
Inventory Reserve	248,053	231,778
Investment Tax Credit	2,523,322	2,523,322
Investment Tax Credit Grant	1,169,174	1,119,598
Litigation Reserve	153,677	30,028
Medical Deductions - Self Insured	119,264	837,727
Monticello Extended Power Uprate Writedown	-	43,265,401
New Hire Retention Credit	52,416	52,102
North Dakota Investment Tax Credit	-	28,475,301
North Dakota Investment Tax Credit - Valuation Allowance	-	(24,784,085)
North Dakota Investment Tax Credit - Federal Gross-Up	-	1,987,578
Nuclear Plant - Decommissioning Provisions	57,101,144	-
Performance Recognition Awards	-	13,145
Post Employment Benefits - Retiree Medical	27,631,779	25,173,957
Post Employment Benefits - Long Term Disability	7,315,959	7,067,199
Prepaid Advertising	876	-
Purchased Power Capacity	97,293	82,616
Rate Refund Reserve	30,784,840	26,297,851

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA			

Regulatory Asset/Liability - Prairie Island Extended Power Uprate Cancellation	3,265,443	2,072,561
Regulatory Asset/Liability - Renewable Energy Standard (RES) Rider	2,069,780	-
Regulatory Asset/Liability - Transmission Attach 0	1,681,774	-
Regulatory Difference - Effect of Rate Changes	213,386	(539,634)
Regulatory Difference - Investment Tax Credit Gross-Up	19,151,230	18,019,282
Research and Experimentation Credit	37,762,865	41,059,275
Sale of Emission Allowances	22,260	11,418
Severance Accrual	315,202	80,314
South Dakota Infrastructure Tracker	354,242	238,621
State Research Credit	3,071,377	3,518,999
State Research Credit - Valuation Allowance	-	(110,751)
State Tax Deduction Cash vs. Accrual	1,577,120	1,013,004
Vacation Accrual	7,533,307	7,388,006
Wind Credit	94,989,187	122,640,676
Workers Compensation	30,793	40,411
Total Electric	\$743,977,350	\$908,770,568

Accumulated Deferred Income Taxes (Account No. 190). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances in the formula. An adjustment is made to eliminate the accumulated deferred income tax balances related to postretirement employee benefits and regulatory differences related to income taxes.

Schedule Page: 234 Line No.: 16 Column: b

	Balance at Beginning of Year	Balance at End of Year
Gas:		
Avoided Tax Interest	\$ 2,370,005	\$ 2,445,068
Bad Debts	867,912	773,354
Conservation Incentive Plan / Demand Side Management	514,242	-
Deferred Connection Fees	8,901,423	9,557,232
Deferred Revenue	57,140	57,117
Economic Development Securities - Write-Off	23,234	22,885
Electric Vehicle Credit	568	556
Employee Incentive Plans	547,465	518,236
Employee Retention	30,011	323
Employee Stock Ownership Program Dividends	1,794,380	1,908,845
Environmental Remediation	55,410	1,207,136
Federal Net Operating Loss	7,851,136	14,427,885
Fuel Tax Credit - Income Addback	656	1,867
Inventory Reserve	20,345	18,549
Litigation Reserve	15,703	3,019
Lower of Cost or Market on Gas Inventories	1,268,123	179,538
Medical Deduction - Self Insured	8,155	62,667
New Hire Retention Credit	3,584	3,898
Performance Recognition Awards	-	983
Post Employment Benefits - Retiree Medical	1,889,352	1,883,176
Post Employment Benefits - Long Term Disability	500,237	528,673
Prepaid Advertising	90	-
Regulatory Difference - Effect of Rate Changes	564,368	535,625
Regulatory Difference - Investment Tax Credit Gross-Up	1,462,517	1,269,737
Severance Accrual	21,552	6,008
State Tax Deduction Cash vs. Accrual	147,541	80,475
Vacation Accrual	515,098	552,671
Workers' Compensation	2,105	3,023

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Total Gas	<u>\$ 29,432,352</u>	<u>\$ 36,048,546</u>

Schedule Page: 234 Line No.: 17 Column: b

	Balance at Beginning of Year	Balance at End of Year
Other:		
Avoided Tax Interest	\$ (875)	\$ (404)
Contributions Carryover	5,858,836	5,897,814
Deferred Compensation Plan Reserve	3,336,752	4,977,582
Federal Net Operating Loss	8,165,295	8,220,880
Fuel Hedging	1,585	783
Low Income Housing Credit	3,344,804	3,344,790
Minnesota Net Operating Loss	1,589,293	15,225,655
North Dakota Net Operating Loss	577,890	1,068,286
Nonqualified Pension Plans	1,276,363	1,102,029
Other Comprehensive Income	14,353,509	14,600,975
Partnership Passthrough	593,407	544,090
Performance Share Plan	166,436	796,647
Regulatory Difference - Effect of Rate Changes	(16)	(16)
State Tax Deduction Cash vs. Accrual	15,682	21,529
Total Other	<u>\$ 39,278,961</u>	<u>\$ 55,800,640</u>

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock			
2	-All NSP-Minnesota common stock is owned by			
3	parent, Xcel Energy Inc.	5,000,000	0.01	
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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.

4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.

5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.

Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
						2
1,000,000	10,000					3
						4
						5
						6
						7
						8
						9
						10
						11
						12
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						40
						41
						42

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)					
Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.					
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.					
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.					
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.					
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.					
Line No.	Item (a)				Amount (b)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of <u>2015/Q4</u>	
CAPITAL STOCK EXPENSE (Account 214)						
1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock. 2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.						
Line No.	Class and Series of Stock (a)				Balance at End of Year (b)	
1	None					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22	TOTAL					

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221		
2	FIRST MORTGAGE BONDS SERIES DUE:		
3			
4	1.95% Aug. 15, 2015 First Mortgage Bonds	250,000,000	2,331,646
5			497,500 D
6			
7	5.25% March 1, 2018 First Mortgage Bonds	500,000,000	4,815,362
8			1,520,000 D
9			
10	2.15% Aug. 15, 2022 First Mortgage Bonds	300,000,000	3,088,686
11			456,000 D
12			
13	7.125% July 1, 2025 First Mortgage Bonds	250,000,000	1,898,288
14			2,330,000 D
15			
16	6.50% March 1, 2028 First Mortgage Bonds	150,000,000	1,474,427
17			1,761,001 D
18			
19	5.25% July 15, 2035 First Mortgage Bonds	250,000,000	3,032,114
20			485,000 D
21			
22	6.25% June 1, 2036 First Mortgage Bonds	400,000,000	4,877,065
23			1,404,000 D
24			
25	6.20% July 1, 2037 First Mortgage Bonds	350,000,000	4,336,843
26			1,988,000 D
27			
28	5.35% Nov. 1, 2039 First Mortgage Bonds	300,000,000	4,153,918
29			570,000 D
30			
31	4.85% Aug. 15, 2040 First Mortgage Bonds	250,000,000	3,019,146
32			707,500 D
33	TOTAL	4,800,000,000	77,179,109

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	3.40% Aug 15, 2042 First Mortgage Bonds	500,000,000	6,272,718
3			3,820,000 D
4			
5	2.60% May 15, 2023 First Mortgage Bonds	400,000,000	4,524,626
6			732,000 D
7			
8	4.125% May 15, 2044 First Mortgage Bonds	300,000,000	3,788,357
9			873,000 D
10			
11	2.20% Aug. 15, 2020 First Mortgage Bonds	300,000,000	3,072,956
12			552,000 D
13			
14	4.00% Aug. 15, 2045 First Mortgage Bonds	300,000,000	3,897,956
15			4,899,000 D
16	SUBTOTAL - ACCOUNT 221	4,800,000,000	77,179,109
17			
18	ACCOUNT 224		
19	OTHER LONG TERM DEBT		
20			
21	Right of Way debt		
22			
23	SUBTOTAL - ACCOUNT 224		
24			
25	Interest on Debt to Associated Companies		
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	4,800,000,000	77,179,109

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
						3
8/11/2010	8/15/2015	8/11/2010	8/15/2015		3,033,333	4
						5
						6
3/18/2008	3/1/2018	3/18/2008	3/1/2018	500,000,000	26,768,134	7
						8
						9
8/13/2012	8/15/2022	8/13/2012	8/15/2022	300,000,000	6,450,000	10
						11
						12
7/1/1995	7/1/2025	7/1/1995	7/1/2025	250,000,000	17,812,500	13
						14
						15
3/1/1998	3/1/2028	3/1/1998	3/1/2028	150,000,000	9,750,000	16
						17
						18
7/21/2005	7/15/2035	7/21/2005	7/15/2035	250,000,000	13,125,000	19
						20
						21
5/25/2006	6/1/2036	5/25/2006	6/1/2036	400,000,000	24,455,460	22
						23
						24
6/26/2007	7/1/2037	6/26/2007	7/1/2037	350,000,000	21,510,859	25
						26
						27
11/17/2009	11/1/2039	11/17/2009	11/1/2039	300,000,000	16,156,993	28
						29
						30
8/11/2010	8/15/2040	8/11/2010	8/15/2040	250,000,000	12,125,000	31
						32
				4,550,033,400	199,909,547	33

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
8/13/2012	8/15/2042	8/13/2012	8/15/2042	500,000,000	18,496,479	2
						3
						4
5/20/2013	5/15/2023	5/20/2013	5/15/2023	400,000,000	10,400,000	5
						6
						7
5/13/2014	5/15/2044	5/13/2014	5/15/2044	300,000,000	12,375,000	8
						9
						10
8/11/2015	8/15/2020	8/11/2015	8/15/2020	300,000,000	2,566,667	11
						12
						13
8/11/2015	8/15/2045	8/11/2015	8/15/2045	300,000,000	4,666,666	14
						15
				4,550,000,000	199,692,091	16
						17
						18
						19
						20
				33,400		21
						22
				33,400		23
						24
					217,456	25
						26
						27
						28
						29
						30
						31
						32
				4,550,033,400	199,909,547	33

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 7 Column: i

Interest at stated rate	\$26,250,000
Interest swap loss	518,134
	<u>\$26,768,134</u>

Schedule Page: 256 Line No.: 22 Column: i

Interest at stated rate	\$25,000,000
Interest swap gain	(544,540)
	<u>\$24,455,460</u>

Schedule Page: 256 Line No.: 25 Column: i

Interest at stated rate	\$21,700,000
Interest swap gain	(189,141)
	<u>\$21,510,859</u>

Schedule Page: 256 Line No.: 28 Column: i

Interest at stated rate	\$16,050,000
Interest swap loss	106,993
	<u>\$16,156,993</u>

Schedule Page: 256.1 Line No.: 2 Column: i

Interest at stated rate	\$17,000,000
Interest swap loss	1,496,479
	<u>\$18,496,479</u>

Schedule Page: 256.1 Line No.: 11 Column: a

Instruction 2:

Minnesota Public Utilities Commission docket E,G002/S-14-922. Order dated Jan. 9, 2015.

NSP-Minnesota issued \$300 million of 2.20 percent First Mortgage Bonds due Aug 15, 2020. NSP-Minnesota used a portion of the net proceeds from the sale to repay redemption of \$250M 1.95 percent first mortgage bond due Aug 15, 2015, short-term borrowings and for other general corporate purposes.

Schedule Page: 256.1 Line No.: 14 Column: a

Instruction 2:

Minnesota Public Utilities Commission docket E,G002/S-14-922. Order dated Jan. 9, 2015.

NSP-Minnesota issued \$300 million of 4.00 percent First Mortgage Bonds due Aug 15, 2045. NSP-Minnesota used a portion of the net proceeds from the sale to repay redemption of \$250M 1.95 percent first mortgage bond due Aug 15, 2015, short-term borrowings and for other general corporate purposes.

Schedule Page: 256.1 Line No.: 21 Column: h

	Balance Dec. 31, 2014	Additions	Reductions	Balance Dec. 31, 2015
Right of Way debt	\$ 45,933	\$	\$ (12,533)	\$ 33,400

Schedule Page: 256.1 Line No.: 25 Column: i

Xcel Energy Services Inc	\$187,341
NSP Nuclear Corp	5,992
Money Pool	24,123
	<u>\$217,456</u>

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.

2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.

3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	356,839,250
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	24,528,523
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		1,292,588,098
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		-30,049,885
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-1,936,180,905
21		
22	Equity in Earnings of Subsidiary Companies	102,171
23		
24	Total Income Tax Expense	180,806,035
25		
26		
27	Federal Tax Net Income	-111,366,713
28	Show Computation of Tax:	
29	Federal Income Tax at 35 percent	-38,978,350
30	Other	5,579,726
31	Total Federal Income Tax Payable	-33,398,624
32		
33		
34		
35		
36		
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41		
42		
43		
44		

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 10 Column: b

DEDUCTIONS RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:

Avoided Cost Interest	\$18,004,906
Book Amortization - Computer Software	38,676,202
Book Amortization - Other	12,031,300
Book Depreciation	435,700,320
Book Income - Wisconsin/South Dakota Allowance for Funds During Construction	334,000
Book Rent Expense - Capitalized for Tax	2,884,080
Book Unamortized Cost of Reacquired Debt	1,927,811
Capitalization of Software Expense - Books	1,747,566
Clearing Account Book Expense	26,047,536
Contributions Carryover	1,287,357
Deferred Compensation Plan Reserve	4,025,126
Employee Stock Ownership Plan Dividends	1,758,857
Environmental Remediation	2,753,085
Federal Net Operating Loss	456,842,642
Lobbying Expenses	1,822,000
Low Income Discount Program	1,777,795
Mark to Market Adjustment	3,272,218
Meals & Entertainment	1,148,000
Medical Deduction - Self Insured	635,752
Monticello Extended Power Uprate Writedown	106,047,849
Nonqualified External Decommissioning Fund (Stock Loss)	3,132,214
Nuclear Decommissioning	21,051,096
Nuclear Fuel Expense	106,424,401
Partnership Passthrough	6,800
Penalties	47,070
Performance Recognition Awards	34,631
Performance Share Plan	1,544,875
Prepaid Insurance	4,230,445
Rate Case/Restructuring Expense	324,228
Regulatory Asset - Gas Safety Deferrals	5,912,844
Suite and Entertainment Tickets	136,000
Unbilled Revenue - Fuel Costs	30,797,914
Unrecovered Renewable Energy Credit Inventory	3,646
Vacation Accrual	191,676
Workers' Compensation	25,856
	<u>\$1,292,588,098</u>

Schedule Page: 261 Line No.: 15 Column: b

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:

Allowance for Funds During Construction (AFDC) - Equity (Non-Conservation Improvement Program)	(\$29,876,881)
Deferred Revenue - Investment Tax Credit (ITC) Grant	(173,004)
	<u>(\$30,049,885)</u>

Schedule Page: 261 Line No.: 20 Column: b

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:

Allowance for Funds During Construction (AFDC) - Debt (Non-Conservation Improvement Program)	(\$14,468,638)
Bad Debts	(2,187,037)
Capital Loss Carryforward	(2,153,177)
Deferred Fuel Costs	(6,175,064)
Deferred Revenue	(448,476)

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/11/2016	2015/Q4
FOOTNOTE DATA			

Electric Vehicle Charging Tariff	(23,418)
Employee Incentive Plans	(2,707,957)
Employee Retention	(1,137,525)
External Qualified Nuclear Decommissioning Fund	(186,764,222)
Fuel Hedging	(1,966)
Gain/(Loss) on Dispositions (Tax)	(5,755,151)
Internally Developed Software	(1,372,339)
Insurance Fund Income (Cash Value)	(1,818,017)
Interest Expense - Capital Leases	(95,061)
Interest Income/Expense on Disputed Tax	(516,910)
Inventory Reserve	(44,029)
Litigation Reserve	(334,000)
Nonqualified Pension Plan	(426,053)
Pension and Benefit Capitalized	(7,502,234)
Pension Expense	(21,132,060)
Post Employment Benefits - Retiree Medical	(6,010,432)
Post Employment Benefits - Long Term Disability	(532,340)
Prepaid Advertising	(2,366)
PUCIP Adjustment	(35,649,706)
Purchased Power Capacity	(35,880)
Rate Refund Reserve	(10,967,741)
Regulatory Asset - Nuclear Refueling Outage Costs	(14,213,380)
Regulatory Asset/Liability - Renewable Energy Standard (RES) Rider	(6,639,046)
Regulatory Asset - Prairie Island Extended Power Uprate Cancellation	(2,920,656)
Regulatory Asset - Property Tax	(198,712)
Regulatory Asset/Liability - Transmission Attach 0	(4,202,128)
Regulatory Asset/Liability - Transmission Cost Recovery Rider	(3,157,290)
Regulatory Asset/Liability - Windsource	(54,569)
Regulatory Reserve - Environmental	(4,141,258)
Repair Expenditures	(103,776,705)
Sale of Emission Allowances	(26,553)
Section 174	(58,800,000)
Severance Accrual	(613,503)
South Dakota Infrastructure Tracker	(283,050)
State Tax Deduction	(73,437)
Tax Amortization - Monticello Rerate	(6,295,644)
Tax Amortization - Computer Software	(21,482,487)
Tax Amortization - Pollution Control Facilities	(1,241,883)
Tax Depreciation	(1,341,524,617)
Tax Expense - Ash Ponds and Landfills	(273,059)
Tax Expense - Spent Fuel Isolation Devices	(22,226,110)
Tax Removal Cost Over Book	(35,775,019)
	<u>(\$1,936,180,905)</u>

Schedule Page: 261 Line No.: 31 Column: b

Northern States Power Company (a Minnesota corporation) is a member of an affiliated group which will file a consolidated federal income tax return for the year 2015. The other members of the affiliated group and the federal income tax provision of each are:

Xcel Energy Inc.	(6,172,248)
NSP Nuclear Corporation	4,064
United Power and Land Company	(13,113)
Northern States Power Company (Wisconsin) and Subsidiaries	(4,651,213)
Public Service Company of Colorado and Subsidiaries	(581,819)
Southwestern Public Service Company	(1,163,610)

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Xcel Energy Communications Group Inc. and Subsidiaries	182,714
Xcel Energy Markets Holdings Inc. and Subsidiaries	340,233
Xcel Energy International Inc.	(2,138)
Xcel Energy Retail Holdings Inc. and Subsidiaries	(15,617)
Xcel Energy Transmission Holding Company, LLC and Subsidiaries	(161,902)
Xcel Energy Ventures Inc. and Subsidiaries	199,412
Xcel Energy Wholesale Group Inc. and Subsidiaries	(323,375)
Xcel Energy WYCO Inc.	8,612,342
WestGas Interstate, Inc.	36,865
Xcel Energy Services Inc.	9,416,558

The consolidated federal income tax liability is apportioned among the member companies based on the stand-alone method. The stand-alone method allocates the consolidated federal income tax liability among the companies based on the recognition of the benefits/burdens contributed by each member to the consolidated return. Under the stand-alone method, the sum of the amounts allocated to the member companies equals the consolidated amount.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	FEDERAL TAXES					
2	Income		8,979,779	-41,022,853	-53,416,555	-24,429,148
3	Income Tax Adjustment			7,624,229		-7,624,229
4						
5	FICA 2015			34,602,169	32,531,596	
6	FICA 2014	2,800,242			2,800,242	
7						
8	Unemployment 2015			226,771	222,493	
9	Unemployment 2014	12,689			12,689	
10						
11	Heavy Vehicle Use Tax			66,074	66,074	
12						
13	SUBTOTAL	2,812,931	8,979,779	1,496,390	-17,783,461	-32,053,377
14						
15	STATE TAXES					
16	MINNESOTA					
17	Income		15,671,155	-4,000,413	29,695	6,959,762
18	Income Tax Adjustment			250,654		-250,654
19						
20	Unemployment 2015			4,813,774	4,715,978	
21	Unemployment 2014	421,588			421,588	
22						
23	Real Estate 2015			102,500,000		
24	Real Estate 2014	105,255,000		-10,071,928	95,183,072	
25	Real Estate directly ex			43,027	43,027	
26						
27	Personal Property 2015			90,000,000		
28	Personal Property 2014	77,745,000		6,999,627	84,744,627	
29	Personal Property directly ex			-26,887	-26,887	
30						
31	Use 2015			8,710,999	-7,329,577	
32	Use 2014	811,421		-207,913	-603,508	
33						
34	SUBTOTAL	184,233,009	15,671,155	199,010,940	177,178,015	6,709,108
35						
36	STATE TAXES					
37	NORTH DAKOTA					
38	Income	224,752		-30,290	32,089	-59,273
39	Income Tax Adjustment			421		-421
40						
41	TOTAL	193,628,086	24,674,744	208,337,547	166,231,898	-25,349,652

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
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3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Unemployment 2015			26,737	25,666	
2	Unemployment 2014	184			184	
3						
4	Personal Property 2015			3,200,000		
5	Personal Property 2014	2,984,550		-173,207	2,811,343	
6						
7	Use 2015			109,127	-120,985	
8	Use 2014	9,430		-4,825	-4,605	
9						
10	SUBTOTAL	3,218,916		3,127,963	2,743,692	-59,694
11						
12	STATE TAXES					
13	SOUTH DAKOTA					
14	Unemployment 2015			14,885	14,780	
15	Unemployment 2014		-202		202	
16						
17	Personal Property 2015			3,700,000		
18	Personal Property 2014	3,300,000		187,189	3,487,189	
19	Personal Property FCA			-198,712	-198,712	
20						
21	Use 2015			236,628	204,889	
22	Use 2014	52,666		42	-52,708	
23						
24	SUBTOTAL	3,352,666	-202	3,940,032	3,455,640	
25						
26	STATE TAXES					
27	KANSAS					
28	Personal Property 2015			630,985	630,985	
29	Personal Property 2014			-4,060	-4,060	
30						
31	SUBTOTAL			626,925	626,925	
32						
33	STATE TAXES					
34	WISCONSIN					
35	Income		24,000	104,342	11,653	54,311
36						
37	Unemployment 2015	14		198	212	
38						
39	SUBTOTAL	14	24,000	104,540	11,865	54,311
40						
41	TOTAL	193,628,086	24,674,744	208,337,547	166,231,898	-25,349,652

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	OTHER					
2	Colorado Unemployment			71	71	
3	Denver Occ'l Priviledge		12	48	48	
4	Property Tax on Rail Car			50,000	7,915	
5	Property Tax on Rail Car	10,550		-4,837	5,713	
6	Other			-14,525	-14,525	
7						
8						
9						
10						
11						
12						
13						
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16						
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36						
37						
38						
39						
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41	TOTAL	193,628,086	24,674,744	208,337,547	166,231,898	-25,349,652

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
	21,015,225	-51,043,343			10,020,490	2
		7,555,475			68,754	3
						4
2,070,573		27,976,469			6,625,700	5
						6
						7
4,278		182,693			44,078	8
						9
						10
		60,955			5,119	11
						12
2,074,851	21,015,225	-15,267,751			16,764,141	13
						14
						15
						16
	12,741,501	-29,034,907			25,034,494	17
		233,550			17,104	18
						19
97,796		3,185,813			1,627,961	20
						21
						22
102,500,000		100,702,000			1,798,000	23
		-9,988,721			-83,207	24
		43,027				25
						26
90,000,000		74,796,000			15,204,000	27
		6,278,371			721,256	28
		-26,887				29
						30
1,381,422		35,369			8,675,630	31
		4,239			-212,152	32
						33
193,979,218	12,741,501	146,227,854			52,783,086	34
						35
						36
						37
103,100		-881,692			851,402	38
		131			290	39
						40
203,255,169	33,768,596	136,036,189			72,301,358	41

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4	
TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)						
5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a). 6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses. 7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority. 8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts. 9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.						
BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
1,071		16,809			9,928	1
						2
						3
3,200,000		2,158,000			1,042,000	4
		-2,365			-170,842	5
						6
	11,858	1,904			107,223	7
		-2,549			-2,276	8
						9
3,304,171	11,858	1,290,238			1,837,725	10
						11
						12
						13
105		9,358			5,527	14
						15
						16
3,700,000		3,700,000				17
		187,189				18
		-198,712				19
						20
31,739		-7,682			244,310	21
		39			3	22
						23
3,731,844		3,690,192			249,840	24
						25
						26
						27
					630,985	28
					-4,060	29
						30
					626,925	31
						32
						33
						34
123,000		97,129			7,213	35
						36
		124			74	37
						38
123,000		97,253			7,287	39
						40
203,255,169	33,768,596	136,036,189			72,301,358	41

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4	
TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)						
5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a). 6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses. 7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority. 8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts. 9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.						
BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
		45			26	2
	12	11,760			-11,712	3
42,085					50,000	4
					-4,837	5
		-13,402			-1,123	6
						7
						8
						9
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203,255,169	33,768,596	136,036,189			72,301,358	41

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 262 Line No.: 2 Column: f

Federal income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)	(\$19,508)
Federal income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	6,532,899
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (207)	(1,512,240)
Federal tax benefit (accrual and cash) for net operating loss carryback accrued in other accounts receivable (143)	(29,430,298)
Rounding	(1)
	<u>(\$24,429,148)</u>

Schedule Page: 262 Line No.: 2 Column: l

Gas (Account No. 409.1)	\$8,912,117
Other income and deductions (Account No. 409.2)	1,108,373
	<u>\$10,020,490</u>

Schedule Page: 262 Line No.: 3 Column: f

Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	(\$8,630,668)
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	1,006,439
	<u>(\$7,624,229)</u>

Schedule Page: 262 Line No.: 3 Column: l

Gas (Account No. 409.1)	\$2,715
Other income and deductions (Account No. 409.2)	66,039
	<u>\$68,754</u>

Schedule Page: 262 Line No.: 5 Column: l

Gas (Account No. 408.1)	\$ 2,263,127
Other income and deductions (Account No. 408.2)	100,154
Other	4,262,419
	<u>\$ 6,625,700</u>

Schedule Page: 262 Line No.: 8 Column: l

Gas (Account No. 408.1)	\$ 14,782
Other income and deductions (Account No. 408.2)	655
Other	28,641
	<u>\$ 44,078</u>

Schedule Page: 262 Line No.: 11 Column: l

Gas (Account No. 408.1)	\$ 5,119

Schedule Page: 262 Line No.: 17 Column: f

State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	\$2,552,426
Annual allocation of unitary benefit/detriment for	4,407,335

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Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Minnesota income tax accrued as additional paid in capital (207)

Rounding

1
<u>\$6,959,762</u>

Schedule Page: 262 Line No.: 17 Column: I

Gas (Account No. 409.1)	\$1,750,720
Other income and deductions (Account No. 409.2)	23,283,774
	<u>\$25,034,494</u>

Schedule Page: 262 Line No.: 18 Column: f

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	(\$252,809)

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	2,155

<u>(\$250,654)</u>

Schedule Page: 262 Line No.: 18 Column: I

Gas (Account No. 409.1)	\$678
Other income and deductions (Account No. 409.2)	16,426
	<u>\$17,104</u>

Schedule Page: 262 Line No.: 20 Column: I

Gas (Account No. 408.1)	\$ 260,205
Other income and deductions (Account No. 408.2)	12,785
Other	1,354,971
	<u>\$ 1,627,961</u>

Schedule Page: 262 Line No.: 23 Column: I

Gas (Account No. 408.1)	\$ 1,738,000
Other income and deductions (Account No. 408.2)	60,000
	<u>\$ 1,798,000</u>

Schedule Page: 262 Line No.: 24 Column: I

Gas (Account No. 408.1)	\$ (83,207)

Schedule Page: 262 Line No.: 27 Column: I

Gas (Account No. 408.1)	\$15,198,000
Other income and deductions (Account No. 408.2)	6,000
	<u>\$15,204,000</u>

Schedule Page: 262 Line No.: 28 Column: I

Gas (Account No. 408.1)	\$ 721,256

Schedule Page: 262 Line No.: 31 Column: I

Gas (Account No. 408.1)	\$ 2,971
Other	8,672,659
	<u>\$ 8,675,630</u>

Schedule Page: 262 Line No.: 32 Column: I

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Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Gas (Account No. 408.1)	\$	356
Other		(212,508)
	\$	<u>(212,152)</u>

Schedule Page: 262 Line No.: 38 Column: f

State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	\$81,686
Annual allocation of unitary benefit/detriment for North Dakota income tax accrued as additional paid in capital (207)	(140,959)
	<u>(\$59,273)</u>

Schedule Page: 262 Line No.: 38 Column: l

Gas (Account No. 409.1)	\$10,701
Other income and deductions (Account No. 409.2)	840,701
	<u>\$851,402</u>

Schedule Page: 262 Line No.: 39 Column: f

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	(\$645)
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	224
	<u>(\$421)</u>

Schedule Page: 262 Line No.: 39 Column: l

Gas (Account No. 409.1)	\$11
Other income and deductions (Account No. 409.2)	279
	<u>\$290</u>

Schedule Page: 262.1 Line No.: 1 Column: l

Gas (Account No. 408.1)	\$	1,377
Other income and deductions (Account No. 408.2)		70
Other		8,481
	\$	<u>9,928</u>

Schedule Page: 262.1 Line No.: 4 Column: l

Gas (Account No. 408.1)	\$	1,042,000

Schedule Page: 262.1 Line No.: 5 Column: l

Gas (Account No. 408.1)	\$	(170,842)

Schedule Page: 262.1 Line No.: 7 Column: l

Gas (Account No. 408.1)	\$	160
Other		107,063
	\$	<u>107,223</u>

Schedule Page: 262.1 Line No.: 8 Column: l

Gas (Account No. 408.1)	\$	(214)
Other		(2,062)
	\$	<u>(2,276)</u>

Schedule Page: 262.1 Line No.: 14 Column: l

Gas (Account No. 408.1)	\$	767

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Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Other income and deductions (Account No. 408.2)	39
Other	4,721
	<u>\$ 5,527</u>

Schedule Page: 262.1 Line No.: 19 Column: a
South Dakota Personal Property Tax collected through the Fuel Clause Adjustment. See page 232.

Schedule Page: 262.1 Line No.: 21 Column: I

Gas (Account No. 408.1)	\$ (645)
Other	244,955
	<u>\$ 244,310</u>

Schedule Page: 262.1 Line No.: 22 Column: I

Gas (Account No. 408.1)	\$ 3

Schedule Page: 262.1 Line No.: 28 Column: I

Gas (Account No. 408.1)	\$ 630,985

Schedule Page: 262.1 Line No.: 29 Column: I

Gas (Account No. 408.1)	\$ (4,060)

Schedule Page: 262.1 Line No.: 35 Column: f

Annual allocation of unitary benefit/detriment for Wisconsin income tax accrued as additional paid in capital (207)	\$54,311
	<u>\$54,311</u>

Schedule Page: 262.1 Line No.: 35 Column: I

Gas (Account No. 409.1)	\$7,213
	<u>\$7,213</u>

Schedule Page: 262.1 Line No.: 37 Column: I

Gas (Account No. 408.1)	\$ 10
Other	64
	<u>\$ 74</u>

Schedule Page: 262.2 Line No.: 2 Column: I

Gas (Account No. 408.1)	\$ 4
Other	22
	<u>\$ 26</u>

Schedule Page: 262.2 Line No.: 3 Column: I

Gas (Account No. 408.1)	\$ 910
Other	(12,622)
	<u>\$ (11,712)</u>

Schedule Page: 262.2 Line No.: 4 Column: a

Property tax on railroad cars used to transport coal from mines to electric generating plants.

Schedule Page: 262.2 Line No.: 4 Column: I

Other	50,000

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 262.2	Line No.: 5	Column: I
Other		(4,837)

Schedule Page: 262.2	Line No.: 6	Column: I
Gas (Account No. 408.1)		\$ (1,123)

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016		Year/Period of Report End of 2015/Q4	
ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)							
Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.							
Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	73,014			411.4	6,388	
4	7%						
5	10%	23,392,825			411.4	1,341,602	
6	30%	1,868,391	236		411.4	97,312	
7							
8	TOTAL	25,334,230				1,445,302	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12	4%	4,384			411.4	2,640	
13	10%	2,107,481			411.4	275,778	
14	TOTAL	2,111,865				278,418	
15							
16	4%	6,604			411.4	445	-1
17	10%	114,189			411.4	4,841	1
18	TOTAL	120,793				5,286	
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48	Utility & Non-Util	27,566,888				1,729,006	

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)					
Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION			Line No.
					1
					2
66,626	54 Years				3
					4
22,051,223	50 Years				5
1,771,079	22 Years				6
					7
23,888,928					8
					9
					10
					11
1,744	47 Years				12
1,831,703	42 Years				13
1,833,447					14
					15
6,158	55 Years				16
109,349	55 Years				17
115,507					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
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					42
					43
					44
					45
					46
					47
25,837,882					48

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 266 Line No.: 8 Column: h

Accumulated Deferred Investment Tax Credits (Account 255). The formula excludes this account because the Company has chosen to utilize the amortization of tax credits against taxable income, that is, income tax expense is reduced by the amount of the amortized investment tax credit.

Schedule Page: 266 Line No.: 18 Column: h

Electric - 92.15%	\$106,438
Gas - 7.85%	9,069
	<u>\$115,507</u>

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4	
OTHER DEFERRED CREDITS (Account 253)						
1. Report below the particulars (details) called for concerning other deferred credits. 2. For any deferred credit being amortized, show the period of amortization. 3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$100,000, whichever is greater) may be grouped by classes.						
Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Unfunded Nonqualified Pension	5,297,727	232	959,920	437,779	4,775,586
2	Benefit Costs					
3						
4	Deferred Compensation					
5	Employees	5,153,701	146	688,046	1,364,007	5,829,662
6	Employees (Wealth Op)	3,021,728	232	741,828	4,090,993	6,370,893
7						
8	Postemployment Benefit-Injury	19,150,584	232	849,618	317,278	18,618,244
9	Compensation					
10						
11	Environmental & Regulatory	216,394	426.5	1,950		214,444
12	Reserves					
13						
14	Nuclear Waste Strategy Coalition	57,865	232	77,354	97,583	78,094
15						
16	Renewable Development Fund	42,645,821	232	23,510,414	25,600,000	44,735,407
17	Obligations					
18						
19	Long-Term Income Tax & Interest	20,970,793	Various	18,557,134	8,117,314	10,530,973
20	Payable					
21						
22	Deposits-Landfill Power	295,383			354	295,737
23						
24	Customer Prepayments	1,163,000	Various	736,000	1,812,750	2,239,750
25						
26	Deferred Revenue	810,475	Various	2,400,742	2,365,053	774,786
27						
28	Wholesale Merger Settlement	82,703				82,703
29						
30	Pre-Funded AFUDC					
31	Metro Emissions Reduction Rider	63,513,764	405	2,231,396		61,282,368
32	Mercury Emissions Reduction Ride	654,612	405	55,577		599,035
33	Minnesota Transmission Cost	26,576,671	Various	731,724	4,628,725	30,473,672
34	Recovery Rider					
35	FERC Transmission	37,715,551	Various	5,318,204	8,750,443	41,147,790
36	Renewable Energy Standards Rider	23,328,047	405	1,133,418		22,194,629
37	South Dakota Transmission	1,258,119	Various	66,669	497,623	1,689,073
38	Cost Recovery Rider					
39	North Dakota Transmission	472,523	Various	54,973	563,007	980,557
40	Cost Recovery Rider					
41						
42	NMC Long-Term Incentive	407,787			670,445	1,078,232
43						
44	Deferred Revenue-ITC Grant	2,325,432	405	173,004		2,152,428
45						
46						
47	TOTAL	315,569,235		72,341,606	72,271,800	315,499,429

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Mark-to-Market Adjustment	13,823,691	Various	4,768,791		9,054,900
2	Mankato/Cannon Falls Lease	40,312,448			1,223,570	41,536,018
3	Normalization					
4						
5	Long-Term Payroll Tax Liability	1,230,240			410,080	1,640,320
6						
7	Coal Car Residual Value Deficit	1,410,531	151	338,528		1,072,003
8						
9	Nuclear Fuel Services	3,673,645	517	3,414,059		259,586
10						
11	Sherco Unit 3 Insurance Settlement		107	5,532,257	11,287,805	5,755,548
12						
13	401 Nicollet Lease Credit				36,991	36,991
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
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36						
37						
38						
39						
40						
41						
42						
43						
44						
45	** Footnote from page 106b					
46						
47	TOTAL	315,569,235		72,341,606	72,271,800	315,499,429

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
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FOOTNOTE DATA			

Schedule Page: 269 Line No.: 19 Column: c

Accounts charged:

186	\$164,138
236	9,002,873
237	506,002
242	8,884,121
Total	<u>\$18,557,134</u>

Schedule Page: 269 Line No.: 24 Column: c

Accounts charged:

142	\$482,000
555	254,000
Total	<u>\$736,000</u>

Schedule Page: 269 Line No.: 26 Column: c

Accounts charged:

232	\$716,250
447	768,600
456	355,892
495	560,000
Total	<u>\$2,400,742</u>

Schedule Page: 269 Line No.: 33 Column: c

Accounts charged:

405	\$407,320
419.1	220,440
432	103,964
Total	<u>\$731,724</u>

Schedule Page: 269 Line No.: 35 Column: c

Accounts charged:

405	\$560,978
419.1	3,235,946
432	1,521,280
Total	<u>\$5,318,204</u>

Schedule Page: 269 Line No.: 35 Column: d

The amount reported for Pre-funded AFUDC-FERC Transmission is a jurisdictional amount. For purposes of calculating the Midcontinent ISO Formula Rate under Attachment O of the Northern States Power Companies FERC Tariff, a total company unjurisdictionalized amortization expense (405) amount is \$831,907.

Schedule Page: 269 Line No.: 35 Column: e

The amount reported for Pre-funded AFUDC-FERC Transmission is a jurisdictional amount. For purposes of calculating the Midcontinent ISO Formula Rate under Attachment O of the Northern States Power Companies FERC Tariff, a total company unjurisdictionalized Pre-funded AFUDC (Total Accounts Other Expenses - 432, Other Revenue - 419.1) amount is \$6,178,766.

Schedule Page: 269 Line No.: 37 Column: c

Accounts charged:

405	\$17,216
419.1	33,555
432	15,898
Total	<u>\$66,669</u>

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Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 269 Line No.: 39 Column: c

Accounts charged:

405	\$6,970
419.1	32,649
432	15,354
Total	<u>\$54,973</u>

Schedule Page: 269.1 Line No.: 1 Column: c

Accounts charged:

253	\$291,667
456	4,477,124
Total	<u>\$4,768,791</u>

Schedule Page: 269.1 Line No.: 45 Column: a

The Form 1 reports that other deferred credits balances at the beginning of year and at the end of the year. Included in this account is the credit for pre-funded AFUDC on CWIP related to the specific transmission projects that are included in the formula. These are jurisdictional amounts. The net pre-funded AFUDC amount used in the Attachment O formula is a total NSP system number (unjurisdictionalized). The formula requires the Company to use a 13 month average balance in the determination of the adjustment to rate base related to this account.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	37,729,105	-2,761,496	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	37,729,105	-2,761,496	
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	37,729,105	-2,761,496	
18	Classification of TOTAL			
19	Federal Income Tax	29,365,634	-2,151,849	
20	State Income Tax	8,363,471	-609,647	
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
						34,967,609	4
							5
							6
							7
						34,967,609	8
							9
							10
							11
							12
							13
							14
							15
							16
						34,967,609	17
							18
						27,213,785	19
						7,753,824	20
							21

NOTES (Continued)

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 272 Line No.: 8 Column: b

	Dec. 31, 2014	410.1	Dec. 31, 2015
Electric - Plant-Related:			
Electric Production Plant	\$ 37,729,105	\$ (2,761,496)	\$ 34,967,609
Total Electric - Plant-Related	\$ 37,729,105	\$ (2,761,496)	\$ 34,967,609

Accumulated Deferred Income Taxes (Account No. 281). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. NSP-Minnesota uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances in the formula.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	2,753,662,213	371,894,574	
3	Gas	184,955,696	17,607,753	
4				
5	TOTAL (Enter Total of lines 2 thru 4)	2,938,617,909	389,502,327	
6	Other (Non-Operating)	422,941		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	2,939,040,850	389,502,327	
10	Classification of TOTAL			
11	Federal Income Tax	2,376,875,339	322,018,809	
12	State Income Tax	562,165,511	67,483,518	
13	Local Income Tax			

NOTES

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
		see note	30,993,636	see note	33,477,449	3,128,040,600	2
		see note	284,613	see note	205,443	202,484,279	3
							4
			31,278,249		33,682,892	3,330,524,879	5
-479,182						-56,241	6
							7
							8
-479,182			31,278,249		33,682,892	3,330,468,638	9
							10
-403,676			18,584,436		22,205,696	2,702,111,732	11
-75,506			12,693,813		11,477,196	628,356,906	12
							13

NOTES (Continued)

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 274 Line No.: 2 Column: b

	Dec. 31, 2014	410.1 & Adjustments	Dec. 31, 2015
Electric - Plant-Related:			
Decommissioning Nonqualified	\$ (2,514,566)	\$ 2,514,566	\$ -
Electric Distribution Plant	679,839,717	48,439,898	728,279,615
Electric General Plant	67,222,583	9,379,058	76,601,641
Electric Intangible Plant	13,222,080	2,295,794	15,517,874
Electric Nuclear Fuel	59,377,392	9,802,238	69,179,630
Electric Nuclear Production Plant	557,011,717	35,851,789	592,863,506
Electric Production Plant	551,352,238	138,039,172	689,391,410
Electric Transmission Plant	563,603,831	116,907,535	680,511,366
Electric Transmission-Production Plant	14,031,569	2,002,814	16,034,383
Common (Allocation to Electric)	17,258,022	6,661,711	23,919,733
Regulatory Differences - Prior Flow Thru	(25,997,117)	522,888	(25,474,229)
Regulatory Differences - AFUDC Equity	193,944,792	3,652,076	197,596,868
Decommissioning Qualified	65,309,955	(1,691,152)	63,618,803
Total Electric - Plant-Related	<u>\$2,753,662,213</u>	<u>\$374,378,387</u>	<u>\$3,128,040,600</u>

Accumulated Deferred Income Taxes (Account No. 282). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances in the formula. An adjustment is made to eliminate the accumulated deferred income tax balances related to regulatory differences related to income taxes.

Schedule Page: 274 Line No.: 2 Column: g

Accounts No. 182.3, 254 and 281

Schedule Page: 274 Line No.: 2 Column: i

Accounts No. 182.3, 254, and 282

Schedule Page: 274 Line No.: 3 Column: g

Accounts No. 182.3, 254, and 282

Schedule Page: 274 Line No.: 3 Column: i

Accounts No. 182.3 and 254

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.

2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric - Plant	32,570,100	2,789,186	
4	Electric - Non-Plant	130,953,702	85,394,284	63,378,794
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	163,523,802	88,183,470	63,378,794
10	Gas			
11	Gas	38,258,372	25,828,620	33,179,118
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	38,258,372	25,828,620	33,179,118
18	Non Operating			
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	201,782,174	114,012,090	96,557,912
20	Classification of TOTAL			
21	Federal Income Tax	162,519,062	90,087,096	75,471,496
22	State Income Tax	39,263,112	23,924,994	21,086,416
23	Local Income Tax			

NOTES

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
 4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
		182.3	232,733	see note	620	35,127,173	3
						152,969,192	4
							5
							6
							7
							8
			232,733		620	188,096,365	9
							10
						30,907,874	11
							12
							13
							14
							15
							16
						30,907,874	17
4,448				219.1	73,148	77,596	18
4,448			232,733		73,768	219,081,835	19
							20
3,475			179,849		57,156	177,015,444	21
973			52,884		16,612	42,066,391	22
							23

NOTES (Continued)

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
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FOOTNOTE DATA			

Schedule Page: 276 Line No.: 3 Column: b

	Dec. 31, 2014	410.1 & Adjustments	Dec. 31, 2015
Electric - Plant-Related:			
Electric Distribution Plant	\$ 191,137	\$ (4,472)	\$ 186,665
Electric General Plant	(15,441)	4,915	(10,526)
Electric Intangible Plant	9,030,615	515,592	9,546,207
Electric Nuclear Production Plant	5,346,059	(287,068)	5,058,991
Electric Production Plant	55,907	(6,027)	49,880
Electric Transmission Plant	59,664	(1,298)	58,366
Common (Allocation to Electric)	15,040,146	2,567,544	17,607,690
Regulatory Differences - AFUDC Equity	2,862,013	(232,113)	2,629,900
Total Electric - Plant-Related	<u>\$ 32,570,100</u>	<u>\$ 2,557,073</u>	<u>\$ 35,127,173</u>

Accumulated Deferred Income Taxes (Account No. 283). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances in the formula. An adjustment is made to eliminate the accumulated deferred income tax balances related to regulatory differences related to income taxes.

Schedule Page: 276 Line No.: 3 Column: i

Accounts No. 182.3 and 283

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4	
OTHER REGULATORY LIABILITIES (Account 254)						
1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable. 2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes. 3. For Regulatory Liabilities being amortized, show period of amortization.						
Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Conservation and Energy Management Program Costs	56,291,007	182.3	56,291,007		
2	Minnesota Electric					
3	- MN Docket E-002/M-15-320					
4						
5	Conservation and Energy Management Program Costs	12,398,882	182.3	12,398,882		
6	Minnesota Natural Gas					
7	- MN Docket G-002/M-15-321					
8						
9	ITC Gross-up to Pre-Tax Rate Levels	20,613,746	190	1,324,729		19,289,017
10						
11	Deferred Tax Collected in Rates in Excess	28,262,161	282	2,247,717	1,165,967	27,180,411
12	of Current Tax Accrual Levels					
13						
14	Unrealized Gains on Decommissioning Trust	172,650,763	128	9,444,897	1,691,151	164,897,017
15						
16	Gain from Sales of Emission Allowances	54,538	411.8	26,657	105	27,986
17	- MN Electric E-002/GR-12-961					
18	- ND Docket PU-12-813					
19	- Amortized over three years (01/2013-12/2016)					
20	- SD Docket EL-12-046					
21	- Amortized over five years (01/2010-01/2015)					
22						
23	PowerON Program	215,589	232	269,050	192,676	139,215
24	- MN Electric E-002/GR-12-961					
25						
26	Rates Collected in Excess of Low Income		182.3	1,993,384	2,436,007	442,623
27	Discounts Provided to Electric Customers					
28	- MN Electric E-002/GR-13-868					
29	- MN Electric E-002/M-04-1956					
30						
31	Rates Collected in Excess of Low Income	1,458,854	Various	3,182,578	2,223,702	499,978
32	Discounts Provided to Natural Gas Customers					
33	- MN Gas G-002/GR-06-1429					
34						
35	Pre-ARO Decommissioning	1,438,393,907			29,674,418	1,468,068,325
36						
37	Derivatives & Hedging - Retail Electric & Gas	35,539,506	175	23,265,636		12,273,870
38						
39	Deferred Electric Commodity Costs	8,350,204	182.3	2,356,473	1,798,960	7,792,691
40						
41	TOTAL	1,835,077,482		182,932,250	81,247,160	1,733,392,392

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016		Year/Period of Report End of 2015/Q4	
OTHER REGULATORY LIABILITIES (Account 254)							
1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable. 2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes. 3. For Regulatory Liabilities being amortized, show period of amortization.							
Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)	
			Account Credited (c)	Amount (d)			
1	Power Purchase Agreement	893,708	555	33,883	14,772	874,597	
2							
3	South Dakota Transmission Cost Recovery Rider	734,739	182.3	218,542		516,197	
4	- SD Docket EL14-080						
5							
6	Minnesota Renewable Energy Standard	5,071,200	182.3	5,071,200			
7	- MN Docket E-002/M-14-733						
8							
9	Minnesota Gas State Energy Policy Rider				947,674	947,674	
10	- MN Docket G-002/M-15-194						
11							
12	Minnesota Renewable Development Fund Rider	2,048,132	182.3	2,048,132			
13	- MN Docket E-002/M-13-905						
14							
15	Department of Energy Settlement Payment	41,790,678	Various	39,938,869	9,771,329	11,623,138	
16	- MN Docket E-002/M-11-807						
17							
18	Department of Energy Settlement Payment	1,131,439	421	14,189,136	14,189,132	1,131,435	
19	Minnesota Decommissioning						
20	- MN Docket E-002/M-11-939						
21							
22	Minnesota Retail Asset Margin Sharing	645,152	557	3,961,836	3,652,494	335,810	
23	- MN Docket E-002/GR-12-961						
24							
25	North Dakota Retail Asset and Non-Asset	749,419	557	1,087,159	696,280	358,540	
26	Margin Sharing						
27	- ND Docket PU-10-657						
28							
29	South Dakota Retail Asset and Non-Asset	790,395	557	784,096	609,965	616,264	
30	Margin Sharing						
31	- SD Docket EL-12-046						
32							
33	South Dakota Production Tax Credit Sharing	(9,586)	557	1,720,208	1,734,940	5,146	
34	- SD Docket EL-11-019						
35							
36	Minnesota Service Quality Program	419,668	142	695,129	1,254,470	979,009	
37	- MN Docket E-002/GR-02-2034						
38	- MN Docket E-002/GR-13-255						
39	- MN Docket E-002/GR-13-371						
40							
41	TOTAL	1,835,077,482		182,932,250	81,247,160	1,733,392,392	

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4	
OTHER REGULATORY LIABILITIES (Account 254)						
1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable. 2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes. 3. For Regulatory Liabilities being amortized, show period of amortization.						
Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	North Dakota Service Quality Program	100,000	Various	100,000	75,000	75,000
2	- ND Docket PU-10-657					
3	- ND Docket PU-11-55					
4	- ND Docket PU-12-813					
5						
6	South Dakota Fuel Clause Adjustment Charge	(5,034)			8,319	3,285
7	- SD EL-12-046					
8						
9	Transmission Formula Rates	5,620,481			3,431,007	9,051,488
10						
11	North Dakota ITC				5,678,792	5,678,792
12						
13	South Dakota Infrastructure	867,934	182.3	283,050		584,884
14	-SD Docket EL-12-046					
15						
16						
17						
18						
19						
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33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	1,835,077,482		182,932,250	81,247,160	1,733,392,392

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 31 Column: c

Accounts charged:

142	\$2,991,210
232	191,368
Total	<u>\$3,182,578</u>

Schedule Page: 278.1 Line No.: 15 Column: c

Accounts charged:

232	\$15,042
254	14,189,132
407.4	25,734,695
Total	<u>\$39,938,869</u>

Schedule Page: 278.2 Line No.: 1 Column: c

Accounts charged:

142	\$24,600
456	75,400
Total	<u>\$100,000</u>

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

ELECTRIC OPERATING REVENUES (Account 400)

- The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
- If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,233,191,223	1,286,558,090
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,437,111,637	1,497,774,351
5	Large (or Ind.) (See Instr. 4)	669,773,812	674,209,749
6	(444) Public Street and Highway Lighting	25,831,661	27,074,906
7	(445) Other Sales to Public Authorities	8,385,549	9,196,760
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	790,906	938,218
10	TOTAL Sales to Ultimate Consumers	3,375,084,788	3,495,752,074
11	(447) Sales for Resale	115,713,391	135,007,695
12	TOTAL Sales of Electricity	3,490,798,179	3,630,759,769
13	(Less) (449.1) Provision for Rate Refunds	3,122,572	85,881,373
14	TOTAL Revenues Net of Prov. for Refunds	3,487,675,607	3,544,878,396
15	Other Operating Revenues		
16	(450) Forfeited Discounts	6,206,620	6,554,056
17	(451) Miscellaneous Service Revenues	3,328,027	3,157,793
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	4,789,673	4,300,152
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	489,884,799	474,061,838
22	(456.1) Revenues from Transmission of Electricity of Others	226,272,583	206,579,869
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	730,481,702	694,653,708
27	TOTAL Electric Operating Revenues	4,218,157,309	4,239,532,104

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
ELECTRIC OPERATING REVENUES (Account 400)					
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.) 7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases. 8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts. 9. Include unmetered sales. Provide details of such Sales in a footnote.					
MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line	
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	No.	
				1	
9,987,615	10,316,636	1,279,780	1,268,637	2	
				3	
15,459,681	15,669,817	154,387	153,339	4	
8,921,526	8,859,210	545	477	5	
166,270	172,113	4,826	4,648	6	
74,272	80,837	2,261	2,278	7	
				8	
10,334	11,228			9	
34,619,698	35,109,841	1,441,799	1,429,379	10	
4,864,428	4,019,303			11	
39,484,126	39,129,144	1,441,799	1,429,379	12	
				13	
39,484,126	39,129,144	1,441,799	1,429,379	14	
Line 12, column (b) includes \$ 8,280,620 of unbilled revenues. Line 12, column (d) includes 697,859 MWH relating to unbilled revenues					

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 300 Line No.: 5 Column: b

Commercial and industrial sales are classified as "Large" for purposes of this report if the customer has a twelve month average minimum registered demand of 1,000 kilowatts or more.

Schedule Page: 300 Line No.: 5 Column: c

Commercial and industrial sales are classified as "Large" for purposes of this report if the customer has a twelve month average minimum registered demand of 1,000 kilowatts or more.

Schedule Page: 300 Line No.: 13 Column: b

Retail interim rates	\$(14,147,759)
Transmission rates	9,258,548
Retail rates - Monticello EPU	8,011,783
	<u>\$ 3,122,572</u>

Final rates in Minnesota electric docket 13-868 were higher than the interim rates billed, resulting in a credit provision for refund.

Schedule Page: 300 Line No.: 17 Column: b

Connection charges	\$ 2,959,644
NSF Check Fees	297,052
Other, less than \$250,000 each	71,331
	<u>\$ 3,328,027</u>

Schedule Page: 300 Line No.: 17 Column: c

Connection charges	\$ 2,912,511
NSF Check Fees	283,127
Other, less than \$250,000 each	(37,845)
	<u>\$ 3,157,793</u>

Schedule Page: 300 Line No.: 19 Column: b

Rent from Electric Property (Account No. 454). The rent revenue credit from electric property included in the formula is income directly related to transmission facilities, such as pole attachments, rentals and special use.

Schedule Page: 300 Line No.: 21 Column: b

Includes reimbursement from Northern States Power Co. (a Wisconsin corporation) for production and transmission costs shared under the FERC-approved Interchange Agreement between the companies restated Jan. 16, 2001.

Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

Fixed Production Expense	\$ 228,879,913
Variable Production Expense	197,322,241
Transmission Expense	46,896,539
Total Interchange Agreement	<u>\$ 473,098,693</u>

Also includes the following items:

Fees charged to burn Refuse Derived Fuel	\$ 6,780,747
Windsor source Program revenue	5,136,030
Net distribution of commodity trading margins under Joint Operating Agreement	2,457,334
Conservation Improvement Program incentive, net of accruals and recoveries	1,119,094

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/11/2016	2015/Q4
FOOTNOTE DATA			

Change in net over-recovered electric commodity costs	557,513
Manitoba Hydro Transmission path re-assignment, energy service agreement and Tatanka transmission fees	539,226
Net MISO market Financial Transmission Rights activity	520,145
Energy Services revenue	516,908
Work on Customers' Equipment	393,706
Twin Cities Hydro distribution facilities charges	354,816
Mutual Aid revenue	294,315
Minnesota Cellnet Labor charges	267,376
Provision for refund under Minnesota and North Dakota jurisdiction	(1,254,077)
Service Quality Plans	
Production Tax Credit refunds	(2,108,435)
Other, less than \$250,000 each	1,211,408
	<u>\$ 489,884,799</u>

Schedule Page: 300 Line No.: 21 Column: c

Includes reimbursement from Northern States Power Co. (a Wisconsin corporation) for production and transmission costs shared under the FERC-approved Interchange Agreement between the companies restated Jan. 16, 2001.

Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

Fixed Production Expense	\$ 229,487,573
Variable Production Expense	208,187,681
Transmission Expense	36,866,599
	<u>\$ 474,541,853</u>

Also includes the following items:

Windsor Program revenue	\$ 6,843,442
Fees charged to burn Refuse Derived Fuel	6,229,293
Net MISO market Financial Transmission Rights activity	2,609,531
Manitoba Hydro Transmission path re-assignment, energy service agreement and Tatanka transmission fees	1,051,075
Reimbursement for moving facilities	751,194
Hazardous Waste processing revenue	535,049
Reimbursement for work on customers' equipment	397,406
Twin Cities Hydro distribution wheeling service revenue	354,816
Energy Services	325,690
Net distribution of commodity trading margins under Joint Operating Agreement	265,155
Provision for refund of lease fees	(583,067)
Provision for refund under Minnesota and North Dakota jurisdiction	(809,350)
Service Quality Plans	
Production Tax Credit refunds	(1,922,146)
Change in net over-recovered electric commodity costs	(3,938,910)
Conservation Improvement Program incentive net of accruals and recoveries	(13,834,818)
Other, less than \$250,000 each	1,245,625
	<u>\$ 474,061,838</u>

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of <u>2015/Q4</u>

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4	
SALES OF ELECTRICITY BY RATE SCHEDULES						
1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311. 2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading. 3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers. 4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly). 5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto. 6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.						
Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL					
2	Minnesota					
3	A00 Water Heating	203	22,865	44	4,614	0.1126
4	A01 Residential	4,839,697	612,891,382	744,514	6,500	0.1266
5	A02 Residential Time of Day	3,054	340,695	253	12,071	0.1116
6	A03 Residential Underground	3,626,443	447,076,296	373,782	9,702	0.1233
7	A04 Residential TOD Undergrnd	2,955	331,861	203	14,557	0.1123
8	A05 Energy Control	35,350	2,842,526	2,994	11,807	0.0804
9	A06 Limited Off Peak	2,878	213,408	381	7,554	0.0742
10	A07 Auto Protective Lighting	6,584	1,138,311			0.1729
11	A08 Residential Vehicle Tariff	7	559			0.0799
12	Unbilled	-11,815	-1,656,645			0.1402
13	North Dakota					
14	D01 Residential	605,073	65,085,158	67,427	8,974	0.1076
15	D02 Residential Time of Day	654	59,233	24	27,250	0.0906
16	D03 Residential Underground	159,326	16,099,112	11,815	13,485	0.1010
17	D04 Residential TOD Undergrnd	99	8,912	4	24,750	0.0900
18	D05 Energy Control	4,133	300,940	296	13,963	0.0728
19	D10 Limited Off Peak	756	49,779	108	7,000	0.0658
20	D11 Auto Protective Lighting	344	56,431			0.1640
21	Unbilled	146	448,314			3.0706
22	South Dakota					
23	E01 Residential	318,471	39,865,498	43,231	7,367	0.1252
24	E03 Residential Underground	389,971	47,542,016	34,496	11,305	0.1219
25	E04 Residential Time of Day	44	4,837	3	14,667	0.1099
26	E06 Residential Heat Pump	1,639	142,571	102	16,069	0.0870
27	E10 Energy Control	1,310	97,358	102	12,843	0.0743
28	E11 Limited Off Peak	14	866	1	14,000	0.0619
29	E12 Auto Protective Lighting	355	67,703			0.1907
30	Unbilled	-76	161,237			-2.1215
31	Total Residential	9,987,615	1,233,191,223	1,279,780	7,804	0.1235
32						
33	COMMERCIAL AND INDUSTRIAL					
34	Minnesota					
35	A05 Energy Control	1,877	147,598	103	18,223	0.0786
36	A06 Limited Off Peak	1,935	154,225	85	22,765	0.0797
37	A07 Auto Protective Lighting	24,424	3,510,802			0.1437
38	A09 Small General Service	25	12,737	99	253	0.5095
39	A10 Small General Service	800,341	96,588,103	74,020	10,812	0.1207
40	A11 Water Heating	248	27,204	84	2,952	0.1097
41	TOTAL Billed	34,636,735	3,378,177,967	1,441,799	24,023	0.0975
42	Total Unbilled Rev.(See Instr. 6)	-17,037	-3,093,179	0	0	0.1816
43	TOTAL	34,619,698	3,375,084,788	1,441,799	24,011	0.0975

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	A12 Small General TOD Service	41,962	4,348,463	2,754	15,237	0.1036
2	A13 Direct Current	7	9,570	4	1,750	1.3671
3	A14 General Service	8,125,915	782,343,577	39,825	204,041	0.0963
4	A15 General TOD Service	8,192,898	629,082,880	4,185	1,957,682	0.0768
5	A16 Small General kWh metered	14,023	1,722,165	2,883	4,864	0.1228
6	A18 Small General TOD Service	28,113	3,168,044	4,384	6,413	0.1127
7	A22 Small Gen TOD Low Watt	2,221	277,830	735	3,022	0.1251
8	A23 Peak Control Tiered	1,234,777	112,258,754	1,560	791,524	0.0909
9	A24 Peak Control Time of Day	2,653,600	194,880,253	369	7,191,328	0.0734
10	A27 Tier 1 Energy Control	433,116	25,961,926	15	28,874,400	0.0599
11	A29 Hiawatha Light Rail	24,077	2,107,766	16	1,504,813	0.0875
12	A63 Experimental Real Time	20,772	1,355,235	2	10,386,000	0.0652
13	Unbilled	-4,005	-2,573,416			0.6426
14	North Dakota					
15	D05 Energy Control	1,429	104,735	49	29,163	0.0733
16	D10 Limited Off Peak	625	55,823	35	17,857	0.0893
17	D11 Auto Protective Lighting	2,710	352,407			0.1300
18	D12 Small General Service	108,613	11,806,710	8,232	13,194	0.1087
19	D14 Small General TOD Service	1,692	158,939	83	20,386	0.0939
20	D16 General Service	718,370	69,487,186	3,500	205,249	0.0967
21	D17 General TOD Service	204,313	16,519,153	180	1,135,072	0.0809
22	D18 Small General TOD Service	558	64,823	101	5,525	0.1162
23	D19 Small General kWh metered	928	127,698	247	3,757	0.1376
24	D20 Peak Control	46,166	4,315,559	68	678,912	0.0935
25	D21 Peak Control Time of Day	125,270	9,180,748	13	9,636,154	0.0733
26	D22 Tier 1 Energy Control	237,469	16,784,217	72	3,298,181	0.0707
27	D34 Sm General TOD Low Watt	68	8,199	21	3,238	0.1206
28	Unbilled	729	658,132			0.9028
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	34,636,735	3,378,177,967	1,441,799	24,023	0.0975
42	Total Unbilled Rev.(See Instr. 6)	-17,037	-3,093,179	0	0	0.1816
43	TOTAL	34,619,698	3,375,084,788	1,441,799	24,011	0.0975

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	South Dakota					
2	E10 Energy Control	128	9,423	8	16,000	0.0736
3	E11 Limited Off Peak	405	30,058	9	45,000	0.0742
4	E12 Auto Protective Lighting	2,270	372,410			0.1641
5	E13 Small General Service	88,635	10,236,478	7,499	11,820	0.1155
6	E14 Small General TOD Service	873	87,106	38	22,974	0.0998
7	E15 General Service	662,097	64,417,544	3,294	201,001	0.0973
8	E16 General TOD Service	442,743	34,853,894	189	2,342,556	0.0787
9	E18 Small General TOD Service	59	8,222	67	881	0.1394
10	E20 Peak Control	60,423	5,965,872	74	816,527	0.0987
11	E21 Peak Control Time of Day	44,706	3,197,000	9	4,967,333	0.0715
12	E22 Energy Control	34,268	2,539,796	21	1,631,810	0.0741
13	Unbilled	-666	159,601			-0.2396
14	Total Commercial and Industrial	24,381,207	2,106,885,449	154,932	157,367	0.0864
15						
16	PUBLIC STREET AND HIGHWAY					
17	Minnesota					
18	A30 Street Light Co Owned	63,081	17,176,801	1,591	39,649	0.2723
19	A32 Street Light Cust Owned	34,774	2,545,447	441	78,853	0.0732
20	A34 Street Lighting Metered	39,644	2,812,393	2,212	17,922	0.0709
21	A37 Street Lighting St Paul	1,040	151,239	1	1,040,000	0.1454
22	Unbilled	-985	-269,443			0.2735
23	North Dakota					
24	D30 Street Light Co Owned	2,236	591,656	49	45,633	0.2646
25	D31 Street Light Cust Owned	11,747	934,666	32	367,094	0.0796
26	D32 Street Lighting Ornamental	37	3,608	2	18,500	0.0975
27	D33 Street Lighting Metered	1,511	98,273	71	21,282	0.0650
28	Unbilled	-5	5,507			-1.1014
29	South Dakota					
30	E30 Street Light Co Owned	1,793	796,603	90	19,922	0.4443
31	E31 Street Light Cust Owned	3,193	292,454	15	212,867	0.0916
32	E32 Street Lighting Metered	6,871	570,968	221	31,090	0.0831
33	E33 Street Lighting Ornamental	1,245	105,034	101	12,327	0.0844
34	Unbilled	88	16,455			0.1870
35	Total Public Street and Highway	166,270	25,831,661	4,826	34,453	0.1554
36						
37						
38						
39						
40						
41	TOTAL Billed	34,636,735	3,378,177,967	1,441,799	24,023	0.0975
42	Total Unbilled Rev.(See Instr. 6)	-17,037	-3,093,179	0	0	0.1816
43	TOTAL	34,619,698	3,375,084,788	1,441,799	24,011	0.0975

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

- Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
- Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
- Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
- The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	OTHER SALES TO PUBLIC					
2	Minnesota					
3	A40 Small Municipal Pumping	6,900	878,993	982	7,026	0.1274
4	A41 Municipal Pumping	54,874	6,165,626	564	97,294	0.1124
5	A42 Fire Siren		35,015	524		
6	Margin Sharing					
7	Unbilled	-425	-51,923			0.1222
8	North Dakota					
9	D40 Small Municipal Pumping	760	86,509	79	9,620	0.1138
10	D41 Municipal Pumping	12,186	1,258,222	89	136,921	0.1033
11	D42 Fire Siren		935	23		
12	Unbilled	-23	9,002			-0.3914
13	South Dakota					
14	E40 Fire Siren		3,170			
15	Total Other Sales to Public Autho	74,272	8,385,549	2,261	32,849	0.1129
16						
17	Interdepartmental Sales	10,334	790,906			0.0765
18	Total Interdepartmental	10,334	790,906			0.0765
19						
20	Footnote for Instruction 5:					
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	34,636,735	3,378,177,967	1,441,799	24,023	0.0975
42	Total Unbilled Rev.(See Instr. 6)	-17,037	-3,093,179	0	0	0.1816
43	TOTAL	34,619,698	3,375,084,788	1,441,799	24,011	0.0975

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/11/2016	2015/Q4
FOOTNOTE DATA			

D34	1,862
D40	20,790
D41	331,162
	<u>\$59,912,817</u>
South Dakota	
E01	\$8,597,220
E03	10,515,274
E04	1,179
E06	44,450
E10	38,746
E11	11,304
E12	51,528
E13	2,386,666
E14	23,467
E15	17,481,553
E16	11,327,379
E18	1,583
E20	1,590,014
E21	1,150,585
E22	892,032
E30	35,189
E31	62,668
E32	134,722
E33	\$24,428
South Dakota jurisdiction	<u>\$54,369,987</u>
Total Company	<u>\$916,171,779</u>

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	NSP- Wisconsin	RQ		N/A	N/A	N/A
2	Basin Electric Power	OS	V6	N/A	N/A	N/A
3	Central Minnesota Municipal Power Agency	OS	V6	N/A	N/A	N/A
4	Central Minnesota Municipal Power Agency	SF	V6	N/A	N/A	N/A
5	City of Ada	OS	V6	N/A	N/A	N/A
6	City of Ada	SF	V6	N/A	N/A	N/A
7	City of Kasota	OS	V6	N/A	N/A	N/A
8	City of Kasota	SF	V6	N/A	N/A	N/A
9	Dahlberg Light and Power	OS	V6	N/A	N/A	N/A
10	Dahlberg Light and Power	SF	V6	N/A	N/A	N/A
11	Interstate Power and Light	OS	V6	N/A	N/A	N/A
12	Midwest Independent System Operator	OS	V6	N/A	N/A	N/A
13	Minnesota Power	OS	V6	N/A	N/A	N/A
14	Minnesota Power	SF	V6	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Missouri River Energy Services	OS	V6	N/A	N/A	N/A
2	North Central Power	OS	V6	N/A	N/A	N/A
3	North Central Power	SF	V6	N/A	N/A	N/A
4	Northwestern Electric Power	OS	V6	N/A	N/A	N/A
5	Northwestern Electric Power	SF	V6	N/A	N/A	N/A
6	Southern Minnesota Municipal Power Agey	OS	V6	N/A	N/A	N/A
7	Wisconsin Power and Light	SF	V6	N/A	N/A	N/A
8						
9	footnote for total \$\$ and mWh					
10	**Footnote from 106b					
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)

demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts.

Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
5,925,267		355,698,521		355,698,521	1
	450,000			450,000	2
123,490		3,120,267		3,120,267	3
80,689		5,386,138		5,386,138	4
	61,500			61,500	5
5,966		465,282		465,282	6
	31,980			31,980	7
3,894		238,270		238,270	8
6,774	126,540	176,340		302,880	9
113,179		5,314,459		5,314,459	10
	118,300			118,300	11
3,427,067	123,850	64,391,070	-2,004,084	62,510,836	12
	218,750			218,750	13
2,400		72,800		72,800	14
5,925,267	0	355,698,521	0	355,698,521	
4,864,428	1,547,510	116,169,965	-2,004,084	115,713,391	
10,789,695	1,547,510	471,868,486	-2,004,084	471,411,912	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
SALES FOR RESALE (Account 447) (Continued)			

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
	148,750			148,750	1
16,723	30,000	375,914		405,914	2
14,517		550,330		550,330	3
68,129	132,840	1,553,210		1,686,050	4
125,600		5,037,080		5,037,080	5
	105,000			105,000	6
876,000		29,488,805		29,488,805	7
					8
					9
					10
					11
					12
					13
					14
5,925,267	0	355,698,521	0	355,698,521	
4,864,428	1,547,510	116,169,965	-2,004,084	115,713,391	
10,789,695	1,547,510	471,868,486	-2,004,084	471,411,912	

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 310 Line No.: 1 Column: a

Ownership interest or affiliation per Instruction 2:

Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) are both wholly owned operating subsidiaries of Xcel Energy Inc.

Schedule Page: 310 Line No.: 12 Column: j

Demand - Resource Adequacy Auction, Other - Ancillary services

Schedule Page: 310.1 Line No.: 9 Column: a

Total revenue and volumes sold will not match pages 300-1, line 11, due to differences in accounting classification associated with the Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) Interchange Agreement.

	Revenue		Mwh
page 300, line 11(b)	\$115,713,391	line 11(d)	4,864,428
page 311 total (k)	\$471,411,912	total (g)	10,789,695
less net interchange agreement	(355,698,521)		(5,925,267)
	<u>\$115,713,391</u>		<u>4,864,428</u>

Schedule Page: 310.1 Line No.: 10 Column: a

Sales for Resale (Account No. 447). The revenue credit from sales for resale included in the formula are for bundled sales that are not included in the formula divisor.

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
ELECTRIC OPERATION AND MAINTENANCE EXPENSES					
If the amount for previous year is not derived from previously reported figures, explain in footnote.					
Line No.	Account (a)	Amount for Current Year (b)		Amount for Previous Year (c)	
1	1. POWER PRODUCTION EXPENSES				
2	A. Steam Power Generation				
3	Operation				
4	(500) Operation Supervision and Engineering	5,260,082		5,232,228	
5	(501) Fuel	334,484,832		388,611,699	
6	(502) Steam Expenses	19,947,733		19,984,537	
7	(503) Steam from Other Sources				
8	(Less) (504) Steam Transferred-Cr.				
9	(505) Electric Expenses	4,453,624		4,912,845	
10	(506) Miscellaneous Steam Power Expenses	20,621,701		21,414,795	
11	(507) Rents	2,899,500		2,889,343	
12	(509) Allowances				
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	387,667,472		443,045,447	
14	Maintenance				
15	(510) Maintenance Supervision and Engineering	2,539,883		2,884,282	
16	(511) Maintenance of Structures	7,119,441		8,080,768	
17	(512) Maintenance of Boiler Plant	35,287,182		41,795,530	
18	(513) Maintenance of Electric Plant	12,890,806		7,364,749	
19	(514) Maintenance of Miscellaneous Steam Plant	14,718,436		15,094,294	
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	72,555,748		75,219,623	
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	460,223,220		518,265,070	
22	B. Nuclear Power Generation				
23	Operation				
24	(517) Operation Supervision and Engineering	68,885,785		83,284,140	
25	(518) Fuel	106,424,403		119,411,936	
26	(519) Coolants and Water	8,558,269		8,334,095	
27	(520) Steam Expenses	48,558,925		51,321,186	
28	(521) Steam from Other Sources				
29	(Less) (522) Steam Transferred-Cr.				
30	(523) Electric Expenses	2,181,969		3,438,776	
31	(524) Miscellaneous Nuclear Power Expenses	137,686,669		140,746,026	
32	(525) Rents	10,584,494		10,473,975	
33	TOTAL Operation (Enter Total of lines 24 thru 32)	382,880,514		417,010,134	
34	Maintenance				
35	(528) Maintenance Supervision and Engineering	8,331,495		12,742,279	
36	(529) Maintenance of Structures	685,835		646,661	
37	(530) Maintenance of Reactor Plant Equipment	38,944,100		39,220,988	
38	(531) Maintenance of Electric Plant	19,566,892		19,309,349	
39	(532) Maintenance of Miscellaneous Nuclear Plant	44,402,887		40,951,887	
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	111,931,209		112,871,164	
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	494,811,723		529,881,298	
42	C. Hydraulic Power Generation				
43	Operation				
44	(535) Operation Supervision and Engineering	1,294		1,600	
45	(536) Water for Power				
46	(537) Hydraulic Expenses	1,088		1,249	
47	(538) Electric Expenses	200,427		194,687	
48	(539) Miscellaneous Hydraulic Power Generation Expenses	147,539		144,847	
49	(540) Rents	17,596		21,450	
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	367,944		363,833	
51	C. Hydraulic Power Generation (Continued)				
52	Maintenance				
53	(541) Maintenance Supervision and Engineering	3,899		22,674	
54	(542) Maintenance of Structures	64,335		122,787	
55	(543) Maintenance of Reservoirs, Dams, and Waterways	106,180		107,611	
56	(544) Maintenance of Electric Plant	33,673		37,579	
57	(545) Maintenance of Miscellaneous Hydraulic Plant	19,460		1,643	
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	227,547		292,294	
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	595,491		656,127	

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)					
If the amount for previous year is not derived from previously reported figures, explain in footnote.					
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)		
60	D. Other Power Generation				
61	Operation				
62	(546) Operation Supervision and Engineering	1,075,250	1,152,385		
63	(547) Fuel	163,685,273	122,566,273		
64	(548) Generation Expenses	8,279,695	7,034,203		
65	(549) Miscellaneous Other Power Generation Expenses	6,047,758	6,215,817		
66	(550) Rents	1,229,970	1,191,121		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	180,317,946	138,159,799		
68	Maintenance				
69	(551) Maintenance Supervision and Engineering	737,897	633,108		
70	(552) Maintenance of Structures	3,147,071	3,903,252		
71	(553) Maintenance of Generating and Electric Plant	9,128,900	11,816,311		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,163,839	2,370,029		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	15,177,707	18,722,700		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	195,495,653	156,882,499		
75	E. Other Power Supply Expenses				
76	(555) Purchased Power	765,036,899	830,958,840		
77	(556) System Control and Load Dispatching	1,274,646	1,339,885		
78	(557) Other Expenses	89,165,471	108,689,927		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	855,477,016	940,988,652		
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,006,603,103	2,146,673,646		
81	2. TRANSMISSION EXPENSES				
82	Operation				
83	(560) Operation Supervision and Engineering	9,626,515	9,411,005		
84					
85	(561.1) Load Dispatch-Reliability	93,311	52,216		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	6,124,802	6,039,176		
87	(561.3) Load Dispatch-Transmission Service and Scheduling		48,570		
88	(561.4) Scheduling, System Control and Dispatch Services	6,963,995	6,245,482		
89	(561.5) Reliability, Planning and Standards Development	75,572	503,377		
90	(561.6) Transmission Service Studies		169		
91	(561.7) Generation Interconnection Studies	-12,231	-181,171		
92	(561.8) Reliability, Planning and Standards Development Services	2,549,889	2,435,880		
93	(562) Station Expenses	1,387,300	1,028,140		
94	(563) Overhead Lines Expenses	1,780,386	2,905,718		
95	(564) Underground Lines Expenses		10,331		
96	(565) Transmission of Electricity by Others	167,127,215	145,642,831		
97	(566) Miscellaneous Transmission Expenses	98,269,153	81,177,872		
98	(567) Rents	2,190,831	2,214,467		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	296,176,738	257,534,063		
100	Maintenance				
101	(568) Maintenance Supervision and Engineering	109,947	128,951		
102	(569) Maintenance of Structures				
103	(569.1) Maintenance of Computer Hardware				
104	(569.2) Maintenance of Computer Software				
105	(569.3) Maintenance of Communication Equipment				
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant				
107	(570) Maintenance of Station Equipment	6,143,250	6,326,544		
108	(571) Maintenance of Overhead Lines	6,905,025	8,504,553		
109	(572) Maintenance of Underground Lines	24,850	186,883		
110	(573) Maintenance of Miscellaneous Transmission Plant	82,504	167,488		
111	TOTAL Maintenance (Total of lines 101 thru 110)	13,265,576	15,314,419		
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	309,442,314	272,848,482		

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)					
If the amount for previous year is not derived from previously reported figures, explain in footnote.					
Line No.	Account (a)	Amount for Current Year (b)		Amount for Previous Year (c)	
113	3. REGIONAL MARKET EXPENSES				
114	Operation				
115	(575.1) Operation Supervision	202,228		182,346	
116	(575.2) Day-Ahead and Real-Time Market Facilitation	72,842		50,292	
117	(575.3) Transmission Rights Market Facilitation				
118	(575.4) Capacity Market Facilitation				
119	(575.5) Ancillary Services Market Facilitation	21,614		6,658	
120	(575.6) Market Monitoring and Compliance	17,791		21,544	
121	(575.7) Market Facilitation, Monitoring and Compliance Services	9,118,563		8,261,156	
122	(575.8) Rents	15,793		15,022	
123	Total Operation (Lines 115 thru 122)	9,448,831		8,537,018	
124	Maintenance				
125	(576.1) Maintenance of Structures and Improvements				
126	(576.2) Maintenance of Computer Hardware				
127	(576.3) Maintenance of Computer Software				
128	(576.4) Maintenance of Communication Equipment				
129	(576.5) Maintenance of Miscellaneous Market Operation Plant				
130	Total Maintenance (Lines 125 thru 129)				
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	9,448,831		8,537,018	
132	4. DISTRIBUTION EXPENSES				
133	Operation				
134	(580) Operation Supervision and Engineering	10,147,712		10,863,731	
135	(581) Load Dispatching	6,382,391		6,591,431	
136	(582) Station Expenses	3,032,582		2,359,426	
137	(583) Overhead Line Expenses	976,590		650,070	
138	(584) Underground Line Expenses	6,189,811		5,048,209	
139	(585) Street Lighting and Signal System Expenses	1,731,993		1,942,074	
140	(586) Meter Expenses	1,598,608		2,433,924	
141	(587) Customer Installations Expenses	1,432,902		1,524,419	
142	(588) Miscellaneous Expenses	11,931,941		13,934,686	
143	(589) Rents	3,842,845		3,788,499	
144	TOTAL Operation (Enter Total of lines 134 thru 143)	47,267,375		49,136,469	
145	Maintenance				
146	(590) Maintenance Supervision and Engineering	616,392		471,624	
147	(591) Maintenance of Structures			9	
148	(592) Maintenance of Station Equipment	8,353,473		8,802,578	
149	(593) Maintenance of Overhead Lines	34,051,009		42,424,018	
150	(594) Maintenance of Underground Lines	11,968,062		12,247,154	
151	(595) Maintenance of Line Transformers	2,537,324		3,098,907	
152	(596) Maintenance of Street Lighting and Signal Systems	1,545,700		1,495,473	
153	(597) Maintenance of Meters	105,988		84,838	
154	(598) Maintenance of Miscellaneous Distribution Plant	6,239		16,744	
155	TOTAL Maintenance (Total of lines 146 thru 154)	59,184,187		68,641,345	
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	106,451,562		117,777,814	
157	5. CUSTOMER ACCOUNTS EXPENSES				
158	Operation				
159	(901) Supervision	117,352		148,797	
160	(902) Meter Reading Expenses	19,076,415		18,585,668	
161	(903) Customer Records and Collection Expenses	24,151,248		25,068,497	
162	(904) Uncollectible Accounts	12,004,811		14,244,377	
163	(905) Miscellaneous Customer Accounts Expenses	1		30	
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	55,349,827		58,047,369	

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)					
If the amount for previous year is not derived from previously reported figures, explain in footnote.					
Line No.	Account (a)	Amount for Current Year (b)		Amount for Previous Year (c)	
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES				
166	Operation				
167	(907) Supervision				
168	(908) Customer Assistance Expenses	68,218,510		123,006,386	
169	(909) Informational and Instructional Expenses	1,235,344		1,073,392	
170	(910) Miscellaneous Customer Service and Informational Expenses				
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	69,453,854		124,079,778	
172	7. SALES EXPENSES				
173	Operation				
174	(911) Supervision				
175	(912) Demonstrating and Selling Expenses	2,110		9,009	
176	(913) Advertising Expenses				
177	(916) Miscellaneous Sales Expenses				
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	2,110		9,009	
179	8. ADMINISTRATIVE AND GENERAL EXPENSES				
180	Operation				
181	(920) Administrative and General Salaries	76,299,639		66,301,093	
182	(921) Office Supplies and Expenses	52,605,695		52,439,082	
183	(Less) (922) Administrative Expenses Transferred-Credit	37,442,700		34,406,201	
184	(923) Outside Services Employed	23,828,798		23,331,471	
185	(924) Property Insurance	9,244,456		9,627,603	
186	(925) Injuries and Damages	14,942,919		15,565,804	
187	(926) Employee Pensions and Benefits	83,907,276		83,065,607	
188	(927) Franchise Requirements				
189	(928) Regulatory Commission Expenses	9,328,994		12,703,189	
190	(929) (Less) Duplicate Charges-Cr.	4,702,073		4,257,282	
191	(930.1) General Advertising Expenses	2,748,734		3,518,540	
192	(930.2) Miscellaneous General Expenses	3,017,246		3,566,764	
193	(931) Rents	27,734,109		24,328,892	
194	TOTAL Operation (Enter Total of lines 181 thru 193)	261,513,093		255,784,562	
195	Maintenance				
196	(935) Maintenance of General Plant	1,565,900		1,429,551	
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	263,078,993		257,214,113	
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,819,830,594		2,985,187,229	

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 320 Line No.: 64 Column: b

Account No. 548 Generation Expenses	\$ 8,279,695
Account No. 548.1 Operation of Energy Storage Equipment	-
	<u>\$ 8,279,695</u>

See Note 15 to the Financial Statements

Schedule Page: 320 Line No.: 64 Column: c

Account No. 548 Generation Expenses	\$ 7,034,203
Account No. 548.1 Operation of Energy Storage Equipment	-
	<u>\$ 7,034,203</u>

See Note 15 to the Financial Statements

Schedule Page: 320 Line No.: 71 Column: b

Account No. 553 Maintenance of Generating and Electric Plant	\$ 9,019,682
Account No. 553.1 Maintenance of Energy Storage Equipment	109,218
	<u>\$ 9,128,900</u>

See Note 15 to the Financial Statements

Schedule Page: 320 Line No.: 71 Column: c

Account No. 553 Maintenance of Generating and Electric Plant	\$ 11,815,701
Account No. 553.1 Maintenance of Energy Storage Equipment	610
	<u>\$ 11,816,311</u>

See Note 15 to the Financial Statements

Schedule Page: 320 Line No.: 76 Column: b

Account No. 555 Purchased Power	\$765,067,809
Account No. 555.1 Power Purchased for Storage Operations	(30,910)
	<u>\$765,036,899</u>

See Note 15 to the Financial Statements

Schedule Page: 320 Line No.: 76 Column: c

Account No. 555 Purchased Power	\$830,943,176
Account No. 555.1 Power Purchased for Storage Operations	15,664
	<u>\$830,958,840</u>

See Note 15 to the Financial Statements

Schedule Page: 320 Line No.: 78 Column: b

Includes \$52,974,220 of fixed costs and \$17,529,413 of variable costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for production costs shared through the FERC-approved Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through a FERC-approved Interchange Agreement.

Schedule Page: 320 Line No.: 78 Column: c

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Includes \$47,367,936 of fixed costs and \$21,335,007 of variable costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for production costs shared through the FERC-approved Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through a FERC-approved Interchange Agreement.

Schedule Page: 320 Line No.: 91 Column: b

Credit balance results from prepaid bid fees related to the utility scale solar program, and also because Pension, Insurance and Taxes on Company labor billed for performing generation interconnection studies is recorded to Account Nos. 408.1, 925 and 926 while the receivable related to performing the studies is recorded to Account No. 561.7.

Schedule Page: 320 Line No.: 91 Column: c

Credit balance results from prepaid bid fees related to the utility scale solar program, and also because Pension, Insurance and Taxes on Company labor billed for performing generation interconnection studies is recorded to Account Nos. 408.1, 925 and 926 while the receivable related to performing the studies is recorded to Account No. 561.7.

Schedule Page: 320 Line No.: 97 Column: b

Includes \$92,751,312 of fixed costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for transmission costs shared through the FERC-approved Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

Schedule Page: 320 Line No.: 97 Column: c

Includes \$76,398,803 of fixed costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for transmission costs shared through the FERC-approved Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

Schedule Page: 320 Line No.: 112 Column: c

Total Transmission Expense as reported in the Form 1, page 321, line 112 is reduced by amounts related to transactions with an affiliated Company based on the FERC-approved Interchange Agreement.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.

2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Adams Wind Generations, LLC	AD		N/A	N/A	N/A
2	Adams Wind Generations, LLC	LU		N/A	N/A	N/A
3	Agassiz Beach LLC	LU		N/A	N/A	N/A
4	Benson Power, LLC	AD		N/A	N/A	N/A
5	Benson Power, LLC	LU		N/A	N/A	N/A
6	Best Power International LLC	LU		N/A	N/A	N/A
7	Big Blue	LU		N/A	N/A	N/A
8	Bisson Windfarm, L.L.C.	LU		N/A	N/A	N/A
9	Boeve Windfarm, L.L.C.	LU		N/A	N/A	N/A
10	Buffalo Ridge Wind Energy, LLC	LU		N/A	N/A	N/A
11	Byllesby	LU		1.8	N/A	N/A
12	Cannon Falls Energy Center	LU		357.0	N/A	N/A
13	Carleton College	LU		N/A	N/A	N/A
14	CG Windfarm, L.L.C.	LU		N/A	N/A	N/A
	Total					

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
PURCHASED POWER (Account 555) (Including power exchanges)			
1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges. 2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller. 3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows: RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers. LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract. IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years. SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less. LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit. IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years. EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges. OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.			

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	John Deere Renewables, L.L.C.	LU		N/A	N/A	N/A
2	Kas Brothers Windfarm, L.L.C.	LU		N/A	N/A	N/A
3	K-Brink Windfarm, L.L.C.	LU		N/A	N/A	N/A
4	KODA Energy, LLC	LU		N/A	N/A	N/A
5	Lake Benton Power Partners, L.L.C.	LU		N/A	N/A	N/A
6	Laurentian Energy Authority, L.L.C.	AD		N/A	N/A	N/A
7	Laurentian Energy Authority, L.L.C.	LU		N/A	N/A	N/A
8	LCO Hydro	LU		N/A	N/A	N/A
9	LSP Cottage Grove Incorporated	LU		253.6	N/A	N/A
10	Luverne Battery	OS		N/A	N/A	N/A
11	Manitoba Hydro	LU		408.3	N/A	N/A
12	Mankato Energy Center, L.L.C.	AD		N/A	N/A	N/A
13	Mankato Energy Center, L.L.C.	LU		375.0	N/A	N/A
14	Metro Wind LLC	LU		N/A	N/A	N/A
	Total					

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Midcontinental ISO	AD		N/A	N/A	N/A
2	Midcontinental ISO	SF		N/A	N/A	N/A
3	MinnDakota	LU		N/A	N/A	N/A
4	Minnkota Power Company	AD			N/A	N/A
5	Minnkota Power Company	LU		50.0	N/A	N/A
6	Minwind Energy, L.L.C.	AD		N/A	N/A	N/A
7	Minwind Energy, L.L.C.	LU		N/A	N/A	N/A
8	Miscellaneous	OS		N/A	N/A	N/A
9	Moraine Wind, L.L.C.	LU		N/A	N/A	N/A
10	NAE Lakota Ridge, LLC	AD		N/A	N/A	N/A
11	NAE Lakota Ridge, LLC	LU		N/A	N/A	N/A
12	NAE Shaokatan, LLC	AD		N/A	N/A	N/A
13	NAE Shaokatan, LLC	LU		N/A	N/A	N/A
14	NAE Shaokatan Hills, LLC	LU		N/A	N/A	N/A
	Total					

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.

2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Neshkoro (Neshonoc)	LU		0.4	N/A	N/A
2	New England ISO	OS		N/A	N/A	N/A
3	New Ulm	OS	NAEMA	N/A	N/A	N/A
4	New York ISO	OS		N/A	N/A	N/A
5	North Community Turbines LLC	LU		N/A	N/A	N/A
6	North Wind Turbines LLC	LU		N/A	N/A	N/A
7	NSP-M Solar Gardens	LU		N/A	N/A	N/A
8	Olsen Windfarms	LU		N/A	N/A	N/A
9	Otter Tail Power Company	AD		N/A	N/A	N/A
10	Pine Bend	LU		N/A	N/A	N/A
11	Pipestone	LU		N/A	N/A	N/A
12	PJM Interconnection LLC	AD		N/A	N/A	N/A
13	PJM Interconnection LLC	OS		N/A	N/A	N/A
14	Prairie Rose Wind LLC	LU		N/A	N/A	N/A
	Total					

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
PURCHASED POWER (Account 555) (Including power exchanges)			
1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges. 2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller. 3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows: RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers. LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract. IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years. SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less. LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit. IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years. EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges. OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.			

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Rapidan Hydroelectric Facility	LU		2.6	N/A	N/A
2	Ridgewind Power Partners, LLC	LU		N/A	N/A	N/A
3	Rock Ridge Power Partners LLC	AD		N/A	N/A	N/A
4	Rock Ridge Power Partners LLC	LU		N/A	N/A	N/A
5	Ruthton Ridge LLC	AD		N/A	N/A	N/A
6	Ruthton Ridge LLC	LU		N/A	N/A	N/A
7	SAF Hydroelectric, L.L.C.	LU		N/A	N/A	N/A
8	Shane's Wind Machine LLC	LU		N/A	N/A	N/A
9	Slayton Solar, LLC	LU		N/A	N/A	N/A
10	South Ridge	AD		N/A	N/A	N/A
11	South Ridge	LU		N/A	N/A	N/A
12	Southwest Power Pool Electric Energy N	AD		N/A	N/A	N/A
13	Southwest Power Pool Electric Energy N	OS		N/A	N/A	N/A
14	St Cloud	LU		7.4	N/A	N/A
Total						

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
PURCHASED POWER (Account 555) (Including power exchanges)			
1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges. 2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller. 3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows: RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers. LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract. IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years. SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less. LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit. IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years. EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges. OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.			

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	St. Olaf College	LU		N/A	N/A	N/A
2	St. Paul Cogeneration	LU		N/A	N/A	N/A
3	TG Windfarm, L.L.C.	LU		N/A	N/A	N/A
4	Tholen	LU		N/A	N/A	N/A
5	Tofteland Windfarm, L.L.C.	LU		N/A	N/A	N/A
6	Uilk Wind Farm, LLC	LU		N/A	N/A	N/A
7	University of Minnesota	AD		N/A	N/A	N/A
8	University of Minnesota	LU		N/A	N/A	N/A
9	Valley View Transmission	LU		N/A	N/A	N/A
10	Velva Windfarm, LLC	LU		N/A	N/A	N/A
11	Viking Wind Partners	LU		N/A	N/A	N/A
12	Western Area Power Administration	LU	NAEMA, WSPP	N/A	N/A	N/A
13	Westridge Windfarm, L.L.C.	LU		N/A	N/A	N/A
14	Windcurrent Farms, L.L.C.	LU		N/A	N/A	N/A
	Total					

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.

2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Windvest	AD		N/A	N/A	N/A
2	Windvest	LU		N/A	N/A	N/A
3	Winona County Wind LLC	LU		N/A	N/A	N/A
4	WM Renewable Energy, LLC	LU		N/A	N/A	N/A
5	Woodstock Hills, L.L.C.	LU		N/A	N/A	N/A
6	Woodstock Municipal Wind, LLC	LU		N/A	N/A	N/A
7	Zephyr Wind	LU		N/A	N/A	N/A
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
				172,820		172,820	1
66,281				4,573,418		4,573,418	2
5,514				220,558		220,558	3
				1,303,340		1,303,340	4
378,491				65,028,674		65,028,674	5
1,024				98,846		98,846	6
130,720				6,654,420		6,654,420	7
6,112				207,773		207,773	8
4,216				141,216		141,216	9
54,388				2,121,919		2,121,919	10
11,518			355,309	238,459		593,768	11
60,400			26,220,836	4,334,138		30,554,974	12
4,447				146,741		146,741	13
3,000				102,019		102,019	14
13,608,589			166,260,806	597,625,307	1,150,786	765,036,899	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
				17,081		17,081	1
223,774				6,831,133		6,831,133	2
28,055				1,373,905		1,373,905	3
					244,000	244,000	4
					-130,000	-130,000	5
178,892			7,106,098	3,986,097		11,092,195	6
17,160				308,587		308,587	7
57,392				3,925,736		3,925,736	8
					2,000	2,000	9
1,123				68,390		68,390	10
27,781				916,674		916,674	11
					44	44	12
					-78,413	-78,413	13
					-3,576	-3,576	14
13,608,589			166,260,806	597,625,307	1,150,786	765,036,899	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
					2,106,556	2,106,556	1
71,654				3,152,776		3,152,776	2
				-41,010		-41,010	3
736,946				32,700,652		32,700,652	4
6,168				215,868		215,868	5
314,010				13,002,091		13,002,091	6
86,602				2,842,748		2,842,748	7
62,540				4,322,843		4,322,843	8
27,961			521,455	551,379		1,072,834	9
482				25,067		25,067	10
				-198,298		-198,298	11
173,212				6,354,483		6,354,483	12
4,131				176,349		176,349	13
12				382		382	14
13,608,589			166,260,806	597,625,307	1,150,786	765,036,899	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
26,028				858,881		858,881	1
2,878				106,682		106,682	2
4,513				151,193		151,193	3
94,655				7,531,563		7,531,563	4
508,406				15,542,149		15,542,149	5
				363,816		363,816	6
262,966				31,220,666		31,220,666	7
10,503				304,945		304,945	8
219,001			44,387,157	6,491,291		50,878,448	9
659				46,376		46,376	10
1,978,136			37,161,196	92,192,798		129,353,994	11
				-527,068		-527,068	12
458,805			35,247,849	14,504,732		49,752,581	13
888				35,508		35,508	14
13,608,589			166,260,806	597,625,307	1,150,786	765,036,899	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
-19,210				-1,448,082		-1,448,082	1
4,464,489				132,026,717		132,026,717	2
548,730				21,487,470		21,487,470	3
				-1,231,408		-1,231,408	4
239,635			13,071,975	4,374,994		17,446,969	5
2,885				95,226		95,226	6
27,304				901,013		901,013	7
					290,225	290,225	8
306,495				15,037,215		15,037,215	9
				-472		-472	10
27,986				1,302,180		1,302,180	11
				-472		-472	12
34,787				1,391,636		1,391,636	13
34,563				1,608,033		1,608,033	14
13,608,589			166,260,806	597,625,307	1,150,786	765,036,899	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
2,291			77,117	48,260		125,377	1
					13,474	13,474	2
			405,000			405,000	3
					433,473	433,473	4
49,119				3,241,830		3,241,830	5
44,740				2,952,828		2,952,828	6
11				123		123	7
3,714				136,771		136,771	8
				4,643		4,643	9
31,600				1,532,168		1,532,168	10
26,633				878,874		878,874	11
					-1,002	-1,002	12
					-1,725,995	-1,725,995	13
683,435				24,250,665		24,250,665	14
13,608,589			166,260,806	597,625,307	1,150,786	765,036,899	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
9,119			370,094	170,032		540,126	1
88,242				6,318,720		6,318,720	2
-232				-7,656		-7,656	3
7,036				232,233		232,233	4
				10		10	5
50,504				2,020,060		2,020,060	6
47,189				2,253,207		2,253,207	7
7,777				256,644		256,644	8
2,725				310,789		310,789	9
-279				-9,196		-9,196	10
6,766				223,287		223,287	11
				229		229	12
1,384				356,089		356,089	13
46,825			1,336,720	922,087		2,258,807	14
13,608,589			166,260,806	597,625,307	1,150,786	765,036,899	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
35				1,129		1,129	1
152,990				23,349,628		23,349,628	2
4,842				164,686		164,686	3
45,967				1,516,719		1,516,719	4
5,921				201,311		201,311	5
14,269				959,789		959,789	6
				10		10	7
3,879				55,429		55,429	8
32,573				2,155,326		2,155,326	9
28,552				942,187		942,187	10
39,296				1,296,467		1,296,467	11
11,767				389,956		389,956	12
4,527				153,894		153,894	13
5,248				183,715		183,715	14
13,608,589			166,260,806	597,625,307	1,150,786	765,036,899	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
-217				-7,172		-7,172	1
6,682				220,487		220,487	2
468				31,700		31,700	3
38,148				1,716,711		1,716,711	4
9,063				388,716		388,716	5
2,311				156,808		156,808	6
114,561				7,410,258		7,410,258	7
							8
							9
							10
							11
							12
							13
							14
13,608,589			166,260,806	597,625,307	1,150,786	765,036,899	

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 2 Column: k
Prior Period Adjustment.
Schedule Page: 326 Line No.: 4 Column: k
Prior Period Adjustment.
Schedule Page: 326 Line No.: 5 Column: k
Formerly FibroMinn.
Schedule Page: 326 Line No.: 10 Column: k
Formerly Windpower Partners 1993, Limited Partnership.
Schedule Page: 326.1 Line No.: 1 Column: k
Prior Period Adjustment.
Schedule Page: 326.1 Line No.: 4 Column: l
Prior Period Adjustment.
Schedule Page: 326.1 Line No.: 5 Column: l
Delayed Damages.
Schedule Page: 326.1 Line No.: 9 Column: l
Land Easements.
Schedule Page: 326.1 Line No.: 12 Column: l
Prior Period Adjustment.
Schedule Page: 326.1 Line No.: 13 Column: l
Comp. for energy without Renewable Energy Credits
Schedule Page: 326.1 Line No.: 14 Column: l
Prior Period Adjustment.
Schedule Page: 326.2 Line No.: 1 Column: l
Financial Trading.
Schedule Page: 326.2 Line No.: 3 Column: k
Prior Period Adjustment.
Schedule Page: 326.2 Line No.: 11 Column: k
Prior Period Adjustment.
Schedule Page: 326.2 Line No.: 14 Column: k
Prior Period Adjustment.
Schedule Page: 326.3 Line No.: 6 Column: k
Prior Period Adjustment.
Schedule Page: 326.3 Line No.: 10 Column: k
Refer to Footnote 15 on Page 123 for further information regarding the Luverne Battery Project.
Schedule Page: 326.3 Line No.: 12 Column: k
Prior Period Adjustment.
Schedule Page: 326.4 Line No.: 1 Column: k
Prior Period Adjustment.
Schedule Page: 326.4 Line No.: 4 Column: k
Prior Period Adjustment.
Schedule Page: 326.4 Line No.: 6 Column: k
Prior Period Adjustment.
Schedule Page: 326.4 Line No.: 8 Column: l
Miscellaneous.
Schedule Page: 326.4 Line No.: 10 Column: k
Prior Period Adjustment.
Schedule Page: 326.4 Line No.: 12 Column: k
Prior Period Adjustment.
Schedule Page: 326.5 Line No.: 2 Column: l
Financial Trading.
Schedule Page: 326.5 Line No.: 3 Column: j
Capacity Credits.
Schedule Page: 326.5 Line No.: 4 Column: l

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Financial Trading.

Schedule Page: 326.5 Line No.: 9 Column: k

Prior Period Adjustment.

Schedule Page: 326.5 Line No.: 12 Column: l

Prior Period Adjustment.

Schedule Page: 326.5 Line No.: 13 Column: l

Financial Trading.

Schedule Page: 326.6 Line No.: 3 Column: k

Prior Period Adjustment.

Schedule Page: 326.6 Line No.: 5 Column: k

Prior Period Adjustment.

Schedule Page: 326.6 Line No.: 10 Column: k

Prior Period Adjustment.

Schedule Page: 326.6 Line No.: 12 Column: k

Prior Period Adjustment.

Schedule Page: 326.6 Line No.: 13 Column: k

Financial Trading.

Schedule Page: 326.7 Line No.: 7 Column: k

Prior Period Adjustment.

Schedule Page: 326.8 Line No.: 1 Column: k

Prior Period Adjustment.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.

2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).

3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)

4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	East Grand Forks, City of	WAPA	East Grand Forks, City of	OS
2	Fairfax, City of	WAPA	Fairfax, City of	AD
3	Granite Falls, City of	WAPA	Granite Falls, City of	OS
4	Great River Energy	Various	Various	FNO
5	Hillsboro, City of	WAPA	Hillsboro, City of	AD
6	Marshall, City of	WAPA & Heartland	Marshall, City of	AD
7	Minnesota Municipal Power Agency (MMPA)	Various	Various	OLF
8	Midcontinent ISO (MISO)	Various	Various	
9	Missouri River Energy Services (MRES)	Various	Various	FNO
10	Sioux Falls, City of	WAPA	Sioux Falls, City of	OS
11	Sleepy Eye, City of	WAPA	Sleepy Eye, City of	AD
12	South Dakota State Penitentiary (SDSP)	WAPA	SDSP	OS
13	Southern MN Municipal Power Agency	Various	Various	FNO
14	St James, City of	WAPA	St James, City of	AD
15	United Power Association	Various	Various	OS
16	University of North Dakota	WAPA	University of North Dakota	OS
17	Wisconsin Public Power, Inc. (WPPI)	MP	WPPI	OS
18				
19	**Footnote from page 106b			
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
483	WAPA	East Grand Forks				1
TM-1	WAPA	Fairfax				2
436	WAPA	Granite Falls				3
Various	Various	Various				4
TM-1	WAPA	Hillsboro				5
TM-1	WAPA, Heartland	Marshall				6
TM-1	Various	Various	180	1,156,096	1,128,999	7
MISO OATT	Various	Various				8
304	Various	Various				9
484	WAPA	Sioux Falls				10
TM-1	WAPA	Sleepy Eye				11
385	WAPA	SDSP				12
304	Various	Various				13
TM-1	WAPA	St James				14
442	Various	Various				15
440	WAPA	UND				16
466	BOSWE44G22.8	WPPI-West				17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			180	1,156,096	1,128,999	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued) (Including transactions referred to as 'wheeling')			
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered. 10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively. 11. Footnote entries and provide explanations following all required data.			

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS				
Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
		48,735	48,735	1
-4			-4	2
		15,527	15,527	3
35,111,306			35,111,306	4
205			205	5
-2,434			-2,434	6
6,536,835			6,536,835	7
108,817,423	63,476,292		172,293,715	8
3,818,121			3,818,121	9
		176,418	176,418	10
-2			-2	11
		13,532	13,532	12
6,135,953			6,135,953	13
1			1	14
		2,010,000	2,010,000	15
		60,195	60,195	16
		54,480	54,480	17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
160,417,404	63,476,292	2,378,887	226,272,583	

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 1 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 2 Column: d

Termination date - 12/31/2014
Adjustments from December 2014

Schedule Page: 328 Line No.: 3 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 4 Column: e

28 and 304

Schedule Page: 328 Line No.: 5 Column: d

Termination date - 12/31/2014
Adjustments from December 2014

Schedule Page: 328 Line No.: 6 Column: d

Termination date - 12/31/2014
Adjustments from December 2014

Schedule Page: 328 Line No.: 7 Column: d

Termination date - 12/31/2015

Schedule Page: 328 Line No.: 8 Column: d

FNO, LFP, SFP, NF

Schedule Page: 328 Line No.: 8 Column: l

MISO Schedule 26-A revenue

Schedule Page: 328 Line No.: 10 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 11 Column: d

Termination date - 12/31/2014
Adjustments from December 2014

Schedule Page: 328 Line No.: 12 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 14 Column: d

Termination date - 12/31/2014

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Adjustments from December 2014

Schedule Page: 328 Line No.: 15 Column: d

Presidential Permit 63-4. Termination date 04/30/2015

Schedule Page: 328 Line No.: 15 Column: m

Facilities Charge Termination Date 04/30/2015

Schedule Page: 328 Line No.: 16 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 17 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 19 Column: a

Revenues from Transmission of Electricity of Others (account 456.1). The revenue credit from transmission of electricity of others included in the formula are from loads that are not included in the formula divisor, and for transmission charges associated with Schedule 26, 26A, 37, and 38 of the MISO OATT.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of <u>2015/Q4</u>

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

- Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
- Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
- In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
- In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
- In column (d) report the revenue amounts as shown on bills or vouchers.
- Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

(Including transactions referred to as "wheeling")

- Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
- In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
- In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
- Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
- Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
- Enter "TOTAL" in column (a) as the last line.
- Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Basin Elec. Power Coop	OS					600	600
2	Central MN Muni Power	FNS			998,219			998,219
3	Dairyland Power	OS					19,311	19,311
4	East River Electric Pwr	OLF			223,477			223,477
5	Great River Energy	FNS			27,284,145			27,284,145
6	McLeod Coop Power Assn	OLF			25,260			25,260
7	Midcontinent Ind Sys Op				89,083,852	29,718,633		118,802,485
8	MN Muni Pwr Agency	FNS			487,267			487,267
9	Minnkota Power Coop	OLF				20,442		20,442
10	NW Wisc Elec (NWEC)	FNS			669,118			669,118
11	So. MN Muni Power	FNS			11,551,415			11,551,415
12	Stearns Coop Electric	OLF				548	2,796	3,344
13	Western Area Pwr Admin				4,985,861		65,286	5,051,147
14	MO River Energy Serv	FNS			1,979,571			1,979,571
15	Southwest Power Pool	FNS			11,414			11,414
16								
	TOTAL				137,299,599	29,739,623	87,993	167,127,215

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 332 Line No.: 1 Column: g

Meter Agent Service Charges

Schedule Page: 332 Line No.: 3 Column: g

Facility Charges

Schedule Page: 332 Line No.: 4 Column: b

Termination date - 10/31/2017

Schedule Page: 332 Line No.: 6 Column: b

Two year notification required for termination.

Schedule Page: 332 Line No.: 7 Column: b

LFP, FNS, FNO

Schedule Page: 332 Line No.: 7 Column: f

MISO Schedule 26-A expense

Schedule Page: 332 Line No.: 9 Column: b

Four year notification required for termination.

Schedule Page: 332 Line No.: 12 Column: b

Two year notification required for termination.

Schedule Page: 332 Line No.: 12 Column: g

Fixed Facility Charge

Schedule Page: 332 Line No.: 13 Column: b

LFP, OS

Termination date - 09/30/2015

Schedule Page: 332 Line No.: 13 Column: g

Schedule 2 (Reactive Supply & Voltage) & Service Charge

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)					
Line No.	Description (a)				Amount (b)
1	Industry Association Dues				1,518,608
2	Nuclear Power Research Expenses				
3	Other Experimental and General Research Expenses				
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities				328,627
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000				
6	Directors' fees and expenses				1,114,142
7	SEC filing expense				55,843
8	Other				26
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				3,017,246

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).

2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.

3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges						
Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			12,628,488		12,628,488
2	Steam Production Plant	89,158,757	3,206,330		-1,131,404	91,233,683
3	Nuclear Production Plant	122,444,239	5,159,947	11,793,443		139,397,629
4	Hydraulic Production Plant-Conventional	1,210,795	9,221	106,828	-67,063	1,259,781
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	68,164,801	1,222,289	155,774	-2,372,152	67,170,712
7	Transmission Plant	59,119,965	5,255		-1,014,519	58,110,701
8	Distribution Plant	103,256,567	46,556			103,303,123
9	Regional Transmission and Market Operation					
10	General Plant	17,568,726			-741	17,567,985
11	Common Plant-Electric	21,546,952	-109,055	21,621,574		43,059,471
12	TOTAL	482,470,802	9,540,543	46,306,107	-4,585,879	533,731,573

B. Basis for Amortization Charges

Account 404 Column (d) Computer software is amortized over its expected useful life of 3, 5, 7, 10 and 15 years.

Account 405 Column (e) Prefunded AFUDC recorded as Other Deferred Credits (Account 253) is amortized over the life of the property, and thus appears as a credit to expense.

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)							
C. Factors Used in Estimating Depreciation Charges							
Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production						
13	310	8,974					
14	311	304,095					
15	312	1,422,276					
16	314	312,006					
17	315	188,804					
18	316	55,252					
19	317	42,865					
20	SUBTOTAL	2,334,272					
21							
22	Nuclear Production						
23	320	1,155					
24	321	488,945					
25	322	1,517,535					
26	323	564,575					
27	324	448,188					
28	325	180,308					
29	326	482,671					
30	SUBTOTAL	3,683,377					
31							
32	Hydro Production						
33	330	1,693					
34	331	1,388					
35	332	9,687					
36	333	10,039					
37	334	3,257					
38	335	61					
39	337	66					
40	SUBTOTAL	26,191					
41							
42	Other Production						
43	340	19,391					
44	341	210,139					
45	342	79,953					
46	344	1,654,190					
47	345	208,915					
48	346	26,923					
49	347	44,173					
50	348	4,129					

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016		Year/Period of Report End of 2015/Q4	
DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)							
C. Factors Used in Estimating Depreciation Charges							
Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	SUBTOTAL	2,247,813					
13							
14	Transmission						
15	350	143,033					
16	352	74,417					
17	353	1,096,621					
18	354	118,578					
19	355	1,093,421					
20	356	469,066					
21	357	25,696					
22	358	30,800					
23	359.1	173					
24	SUBTOTAL	3,051,805					
25							
26	Distribution						
27	360	16,105					
28	361	43,951					
29	362	574,725					
30	364	362,273					
31	365	412,333					
32	366	253,862					
33	367	1,041,843					
34	368	400,435					
35	368	19,239					
36	369	80,846					
37	369	206,072					
38	370	110,035					
39	371	19,791					
40	371	1,635					
41	371	1,280					
42	373	59,990					
43	374	3,672					
44	SUBTOTAL	3,608,087					
45							
46	General						
47	389	4,439					
48	390	61,224					
49	391	25,100					
50	391	22,267					

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016		Year/Period of Report End of 2015/Q4	
DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)							
C. Factors Used in Estimating Depreciation Charges							
Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	392	552					
13	392	29,551					
14	392	14,425					
15	392	81,278					
16	393	1,753					
17	394	74,127					
18	395	3,387					
19	396	37,554					
20	397	16,567					
21	397	1,192					
22	397	21,245					
23	397	7,072					
24	398	2,869					
25	SUBTOTAL	404,602					
26							
27	TOTAL	15,356,147					
28							
29							
30							
31							
32							
33							
34							
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48							
49							
50							

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 336 Line No.: 7 Column: b

Transmission Serving Production \$ 1,100,856

Schedule Page: 336 Line No.: 8 Column: b

Distribution Serving Production \$ 76,904

Schedule Page: 336.1 Line No.: 34 Column: a

Line Transformers

Schedule Page: 336.1 Line No.: 35 Column: a

Line Capacitors

Schedule Page: 336.1 Line No.: 36 Column: a

Overhead Services

Schedule Page: 336.1 Line No.: 37 Column: a

Underground Services

Schedule Page: 336.1 Line No.: 39 Column: a

Installation on Customer Premises (Minnesota)

Schedule Page: 336.1 Line No.: 40 Column: a

Installation on Customer Premises (South Dakota)

Schedule Page: 336.1 Line No.: 41 Column: a

Installation on Customer Premises (North Dakota)

Schedule Page: 336.1 Line No.: 49 Column: a

Office Furniture and Equipment

Schedule Page: 336.1 Line No.: 50 Column: a

Network Equipment

Schedule Page: 336.2 Line No.: 12 Column: a

Transportation Equipment - Automobiles

Schedule Page: 336.2 Line No.: 13 Column: a

Transportation Equipment - Light Trucks

Schedule Page: 336.2 Line No.: 14 Column: a

Transportation Equipment - Trailers

Schedule Page: 336.2 Line No.: 15 Column: a

Transportation Equipment - Heavy Trucks

Schedule Page: 336.2 Line No.: 19 Column: a

Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1).

	Charged to Clearing Accts	Depreciable Plant Base
392 Transportation Equipment	\$ 8,674,719	\$ 125,806,000
396 Power Operated Equipment	3,075,435	37,554,000
Total	\$ 11,750,154	\$ 163,360,000

Schedule Page: 336.2 Line No.: 20 Column: a

Communication Equipment

Schedule Page: 336.2 Line No.: 21 Column: a

Communication Equipment - Two Way

Schedule Page: 336.2 Line No.: 22 Column: a

Communication Equipment - EMS

Schedule Page: 336.2 Line No.: 23 Column: a

Communication Equipment - AMR

Schedule Page: 336.2 Line No.: 27 Column: b

(1) Column (b) Computation:

Depreciable Plant Balances are an average of the beginning and ending plant balance

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

for the year.

(2) Column (c) through (g):

Subaccounts 311-346: A remaining life technique is applied to each generating facility. No changes to the underlying factors presented in columns (c) through (g) have occurred since filing the 2014 FERC Form 1.

(3) P337 Line 23 - 29 (d) - Effective Aug. 1, 1981, Nuclear Plant Decommissioning costs are recovered using an external sinking fund calculation.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.

2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	MINNESOTA DEPARTMENT OF COMMERCE				
2	Assessments	2,007,290		2,007,290	
3	Assessments	265,290		265,290	
4	State Energy Policy Tracker		20,656	20,656	
5					
6	MINNESOTA PUBLIC UTILITIES COMMISSION				
7	[no docket future] Retail Rate Case		39,810	39,810	
8	GR12-961 2012 Retail Rate Case		13	13	
9	GR13-868 2014 Retail Rate Case		2,900,274	2,900,274	
10	Prairie Island Tribal Payments		-362,500	-362,500	
11	Assessments	2,257,617		2,257,617	
12	Assessments	355,809		355,809	
13					
14	NORTH DAKOTA PUBLIC SERVICE COMMISSION				
15	PU10-657 2010 Retail Rate Case		29	29	
16	PU12-813 2012 Retail Rate Case		207,614	207,614	
17	Assessments	193,739		193,739	
18	Assessments	-8,900		-8,900	
19					
20	SOUTH DAKOTA PUBLIC UTILITIES COMMISSION				
21	EL14-058 2014 Retail Rate Case		119,193	119,193	
22	Riders		6,543	6,543	
23	Assessments	284,573		284,573	
24					
25	Other				
26	Mandated inserts		46,114	46,114	
27	Mandated inserts		347	347	
28	Miscellaneous		1,647,839	1,647,839	
29	Miscellaneous		34,058	34,058	
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	5,355,418	4,659,990	10,015,408	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

REGULATORY COMMISSION EXPENSES (Continued)							
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.							
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.							
5. Minor items (less than \$25,000) may be grouped.							

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
Electric	928	2,007,290					2
Gas	928	265,290					3
Electric	928	20,656					4
							5
							6
Gas	928	39,810					7
Electric	928	13					8
Electric	928	2,900,274		186	1,832,000		9
Electric	928	-362,500					10
Electric	928	2,257,617					11
Gas	928	355,809					12
							13
							14
Electric	928	29					15
Electric	928	207,614		186	207,606		16
Electric	928	193,739					17
Gas	928	-8,900					18
							19
							20
Electric	928	119,193		186	119,193		21
Electric	928	6,543					22
Electric	928	284,573					23
							24
							25
Electric	928	46,114					26
Gas	928	347					27
Electric	928	1,647,839					28
Gas	928	34,058					29
							30
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		10,015,408			2,158,799		46

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 350 Line No.: 9 Column: k
 GR13-868: 24 month amortization period ending Dec. 31, 2015.

Schedule Page: 350 Line No.: 16 Column: k
 PU12-813:48 month amortization period ending Dec. 31, 2016.

Schedule Page: 350 Line No.: 21 Column: k
 EL14-058: 36 month amortization period ending Dec. 31, 2017.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES			
1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts). 2. Indicate in column (a) the applicable classification, as shown below: Classifications: A. Electric R, D & D Performed Internally: (1) Generation a. hydroelectric i. Recreation fish and wildlife ii Other hydroelectric b. Fossil-fuel steam c. Internal combustion or gas turbine d. Nuclear e. Unconventional generation f. Siting and heat rejection (2) Transmission a. Overhead b. Underground (3) Distribution (4) Regional Transmission and Market Operation (5) Environment (other than equipment) (6) Other (Classify and include items in excess of \$50,000.) (7) Total Cost Incurred			

B. Electric, R, D & D Performed Externally:

(1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B(1)	Electric Power Research Institute
2		
3	B(2)	Edison Electric Institute
4		
5	B(4)	Renewable Development Fund
6		
7	B(5)	Total
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
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19		
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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

- (2) Research Support to Edison Electric Institute
 (3) Research Support to Nuclear Power Groups
 (4) Research Support to Others (Classify)
 (5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
	2,988,246	Various	2,988,246		1
					2
	935,637	Various	935,637		3
					4
	737,550	253	737,550		5
					6
	4,661,433		4,661,433		7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
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					38

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/11/2016	2015/Q4
FOOTNOTE DATA			

Schedule Page: 352 Line No.: 1 Column: e

Accounts charged:

517	\$2,456,776
566	45,000
921	37,057
923	36,446
930.2	412,967
	<u>\$2,988,246</u>

Schedule Page: 352 Line No.: 3 Column: e

Accounts charged:

426.1	\$13,529
426.4	112,191
560	57,538
923	18,422
930.2	733,957
	<u>\$935,637</u>

Schedule Page: 352 Line No.: 5 Column: b

The "Renewable Development Fund" is a program authorized by Minnesota Statute 116C3.779. Funding through this statute supports energy production and research and development of alternative sources of electricity. The projects listed below support the research and development of renewable sources of electricity. Also see page 269, Other Deferred Credits (Account 253).

Research Projects

University of Minnesota-Koda Energy	\$74,629
Minnesota Valley Alfalfa	662,921
	<u>\$737,550</u>

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4
DISTRIBUTION OF SALARIES AND WAGES					
Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.					
Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)	
1	Electric				
2	Operation				
3	Production	200,248,756			
4	Transmission	12,584,412			
5	Regional Market	280,724			
6	Distribution	32,797,834			
7	Customer Accounts	14,108,205			
8	Customer Service and Informational	1,507,495			
9	Sales				
10	Administrative and General	76,355,281			
11	TOTAL Operation (Enter Total of lines 3 thru 10)	337,882,707			
12	Maintenance				
13	Production	91,324,367			
14	Transmission	4,294,613			
15	Regional Market				
16	Distribution	23,344,429			
17	Administrative and General				
18	TOTAL Maintenance (Total of lines 13 thru 17)	118,963,409			
19	Total Operation and Maintenance				
20	Production (Enter Total of lines 3 and 13)	291,573,123			
21	Transmission (Enter Total of lines 4 and 14)	16,879,025			
22	Regional Market (Enter Total of Lines 5 and 15)	280,724			
23	Distribution (Enter Total of lines 6 and 16)	56,142,263			
24	Customer Accounts (Transcribe from line 7)	14,108,205			
25	Customer Service and Informational (Transcribe from line 8)	1,507,495			
26	Sales (Transcribe from line 9)				
27	Administrative and General (Enter Total of lines 10 and 17)	76,355,281			
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	456,846,116	16,663,623	473,509,739	
29	Gas				
30	Operation				
31	Production-Manufactured Gas	619,144			
32	Production-Nat. Gas (Including Expl. and Dev.)	43,670			
33	Other Gas Supply	321,719			
34	Storage, LNG Terminaling and Processing	1,186,593			
35	Transmission	962,512			
36	Distribution	15,995,595			
37	Customer Accounts	3,476,518			
38	Customer Service and Informational	934,028			
39	Sales				
40	Administrative and General	6,226,064			
41	TOTAL Operation (Enter Total of lines 31 thru 40)	29,765,843			
42	Maintenance				
43	Production-Manufactured Gas	148,337			
44	Production-Natural Gas (Including Exploration and Development)				
45	Other Gas Supply				
46	Storage, LNG Terminaling and Processing	228,607			
47	Transmission	6,333			

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DISTRIBUTION OF SALARIES AND WAGES (Continued)					
Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)	
48	Distribution	4,445,344			
49	Administrative and General				
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	4,828,621			
51	Total Operation and Maintenance				
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	767,481			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	43,670			
54	Other Gas Supply (Enter Total of lines 33 and 45)	321,719			
55	Storage, LNG Terminating and Processing (Total of lines 31 thru	1,415,200			
56	Transmission (Lines 35 and 47)	968,845			
57	Distribution (Lines 36 and 48)	20,440,939			
58	Customer Accounts (Line 37)	3,476,518			
59	Customer Service and Informational (Line 38)	934,028			
60	Sales (Line 39)				
61	Administrative and General (Lines 40 and 49)	6,226,064			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	34,594,464	1,261,845	35,856,309	
63	Other Utility Departments				
64	Operation and Maintenance				
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	491,440,580	17,925,468	509,366,048	
66	Utility Plant				
67	Construction (By Utility Departments)				
68	Electric Plant	142,426,035	5,195,040	147,621,075	
69	Gas Plant	10,924,923	398,490	11,323,413	
70	Other (provide details in footnote):	379,175	13,831	393,006	
71	TOTAL Construction (Total of lines 68 thru 70)	153,730,133	5,607,361	159,337,494	
72	Plant Removal (By Utility Departments)				
73	Electric Plant	9,487,431	346,057	9,833,488	
74	Gas Plant	351,199	12,810	364,009	
75	Other (provide details in footnote):				
76	TOTAL Plant Removal (Total of lines 73 thru 75)	9,838,630	358,867	10,197,497	
77	Other Accounts (Specify, provide details in footnote):				
78	Regulatory Assets Acct No. 182.3	7,732,223	282,036	8,014,259	
79	Regulatory Liabilities Acct No. 254	131,886	4,811	136,697	
80	Expenses of Nonutility Operations Acct No. 417.1	880,807	32,128	912,935	
81	Miscellaneous Income and Deductions Acct No. 426.4	379,616	13,847	393,463	
82					
83					
84					
85					
86					
87					
88					
89					
90					
91					
92					
93					
94					
95	TOTAL Other Accounts	9,124,532	332,822	9,457,354	
96	TOTAL SALARIES AND WAGES	664,133,875	24,224,518	688,358,393	

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 354 Line No.: 70 Column: b	
Account No. 121 Nonutility Property	\$ 379,175

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) ☒ An Original (2) ☐ A Resubmission	04/11/2016	End of 2015/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Instruction 1:

Account -----	Allocated to Utility Departments		Cost at Dec. 31, 2015 -----
	Electric -----	Gas -----	
COMMON UTILITY PLANT IN SERVICE AND COMPLETED NOT CLASSIFIED			
301 Organization	\$ 85,295	\$ 15,313	\$ 100,608
303 Computer Software	276,464,406	49,631,850	326,096,256
	-----	-----	-----
Total intangible plant	\$276,549,701	\$49,647,163	\$326,196,864

389 Land and land rights	\$ 5,715,823	\$ 481,085	\$ 6,196,908
390 Structures and improvements	140,429,739	11,819,571	152,249,310
391 Office furniture and equipment	98,533,342	8,293,270	106,826,612
392 Transportation equipment	11,631,884	846,511	12,478,395
393 Stores equipment	162,505	13,678	176,183
394 Tools/shop/garage equipment	3,388,284	285,182	3,673,466
395 Laboratory equipment	33,838	2,848	36,686
396 Power operated equipment	885,971	68,889	954,860
397 Communications equipment	4,244,843	357,276	4,602,119
398 Miscellaneous equipment	590,411	49,693	640,104
399.1 Asset retirement costs for general plant	(1,749,697)	(147,267)	(1,896,964)
	-----	-----	-----
	540,416,644	\$71,717,899	\$612,134,543

COMMON UTILITY PLANT HELD FOR FUTURE USE

389 Land and Land Rights	\$-	\$-	\$-

COMMON UTILITY PLANT CONSTRUCTION WORK IN PROGRESS

General plant	\$ 57,363,785	\$ 9,029,042	\$ 66,392,827

COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

General Plant	\$266,569,174	\$ 41,080,918	\$307,650,092

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

COMMON UTILITY PLANT AND EXPENSES

- Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
- Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
- Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
- Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Common utility plant and accumulated provision for depreciation has been allocated to the various utilities on the basis of customers, employee labor, or direct assignment based on actual use.

Instruction 2:

DEPARTMENTAL ALLOCATION OF ACCUMULATED PROVISION FOR DEPRECIATION

"Non-Legal" ARO
Balances

Common General	\$ (8,026,708)
Common Intangible	-

Total Common	\$ (8,026,708)

Instruction 3:

COMMON UTILITY PLANT EXPENSES

	Electric -----	Gas -----	Total -----
403 Depreciation Expense	\$21,546,952	\$1,809,118	\$23,356,070
403.1 Depreciation Expense - ARC	(109,055)	(9,209)	(118,264)
404 Amortization of limited term plant	21,621,574	3,716,904	25,338,478
407.4 Amortization of regulatory credits	(67,046)	5,222	(61,824)
411.1 Accretion expense	47,231	3,988	51,219
	-----	-----	-----
	\$43,039,656	\$5,526,023	\$48,565,679

Basis of allocation of Common Utility Plant expenses:

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/11/2016	End of 2015/Q4

COMMON UTILITY PLANT AND EXPENSES

- 1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
- 2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
- 3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
- 4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

From	Through	Allocation Methods
----	-----	-----
403	403	Depreciation allocator (excluding integrated software)
404	404	Software amortization allocator
407.4	407.4	3-factor (operating revenue, plant in service, supervised O&M)
Common Utility Plant and Accumulated Provision for Depreciation. The Form 1 reports common utility plant and accumulated provision for depreciation allocated to the electric department at the end of the year. The Company uses a 13-month average calculation for the electric department common utility plant and accumulated provision for depreciation in the formula.		
Common plant operation and maintenance charges and rents are not separately accounted for and, therefore, are not available.		
Instruction 4: The use of common utility plant classification was recommended by Federal Power Commission letter dated Aug. 14, 1969.		

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	MISO				
8	Net Purchases (Account 555)	40,524,596	85,934,105	127,434,803	157,106,064
9	Net Sales (Account 447)	(17,657,551)	(25,747,148)	(44,474,965)	(61,389,416)
10	Transmission Rights	(8,671,013)	(14,257,702)	(23,790,896)	(28,573,010)
11	Ancillary Services	(92,459)	113,255	(17,179)	(114,753)
12	Other Items (list separately)				
13	Admin Fees	2,228,323	4,156,059	6,063,466	7,965,746
14	Net Purchases for Storage Operations		(7,462)		(2,515)
15	ERCOT				
16	Net Purchases (Account 555)	968,150	958,715	1,478,362	1,707,409
17	Net Sales (Account 447)				
18	Transmission Rights	82,154	169,922	284,750	391,769
19	Ancillary Services				
20	Other Items				
21	Uplift Charges	1,648	3,079	3,532	3,800
22	NEISO				
23	Net Purchases (Account 555)				
24	Net Sales (Account 447)				
25	Transmission Rights				
26	Ancillary Services				
27	Other Items				
28	Admin Fees	1,879	5,323	9,264	13,475
29	NYISO				
30	Net Purchases (Account 555)	503,234	526,263	300,325	450,933
31	Transmission Rights	(68,208)	(33,549)	(33,549)	(33,549)
32	Admin Fees	11,477	17,529	24,693	26,724
33	PJM				
34	Net Purchases (Account 555)	(148,713)	(1,172,503)	(1,115,109)	(1,120,997)
35	Net Sales (Account 447)				
36	Transmission Rights	(80,873)	(912,810)	(910,743)	(806,419)
37	Ancillary Services				
38	Other Items				
39	Admin Fees	7,330	15,260	21,236	29,304
40	Uplift Charges	78,819	127,274	158,612	171,115
41	SPP				
42	Net Purchases (Account 555)	(11,091)	30,882	30,882	30,564
43	Transmission Rights	15,626	95,487	108,904	282,469
44	Admin Fees	25	66	66	66
45	Uplift Charges	2,465	5,459	5,549	5,549
46	TOTAL	17,695,818	50,027,504	65,582,003	76,144,328

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 398 Line No.: 1 Column: b

Number of units is not available

Schedule Page: 398 Line No.: 1 Column: e

Volume of units is not available

Schedule Page: 398 Line No.: 2 Column: b

Number of units is not available

Schedule Page: 398 Line No.: 2 Column: e

Volume of units is not available

Schedule Page: 398 Line No.: 3 Column: b

Number of units is not available

Schedule Page: 398 Line No.: 3 Column: e

Volume of units is not available

Schedule Page: 398 Line No.: 4 Column: b

Number of units is not available

Schedule Page: 398 Line No.: 4 Column: e

Volume of units is not available

Schedule Page: 398 Line No.: 5 Column: b

Number of units is not available

Schedule Page: 398 Line No.: 5 Column: e

Volume of units is not available

Schedule Page: 398 Line No.: 6 Column: b

Number of units is not available

Schedule Page: 398 Line No.: 6 Column: e

Volume of units is not available

Schedule Page: 398 Line No.: 7 Column: b

Number of units is not available

Schedule Page: 398 Line No.: 7 Column: d

SCH 10 "ISO Cost Recovery Adder"
Ancillary Services

\$ 10,492,848
34,200

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Service Charge	22,976
Total Other Charges	<u>\$ 10,550,024</u>

Schedule Page: 398 Line No.: 7 Column: e

Volume of units is not available

Name of Respondent Northern States Power Company (Minnesota)					This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016		Year/Period of Report End of 2015/Q4	
MONTHLY TRANSMISSION SYSTEM PEAK LOAD										
(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system. (2) Report on Column (b) by month the transmission system's peak load. (3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b). (4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.										
NAME OF SYSTEM: Norther States Power Co. Intergrated System										
Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	7,599	7	1800	6,365	501	502			
2	February	7,353	18	1900	6,111	515	502			
3	March	7,040	4	2000	5,849	476	502			
4	Total for Quarter 1				18,325	1,492	1,506			
5	April	6,364	9	1200	5,346	408	502			
6	May	7,384	28	1600	6,184	429	502			
7	June	8,831	9	1700	7,395	495	502			
8	Total for Quarter 2				18,925	1,332	1,506			
9	July	9,397	27	1700	7,977	552	502			
10	August	9,767	14	1600	8,110	567	502			
11	September	9,382	3	1700	7,866	549	502			
12	Total for Quarter 3				23,953	1,668	1,506			
13	October	6,417	8	1200	5,376	399	502			
14	November	6,868	30	1800	5,662	445	502			
15	December	7,002	17	1800	5,821	455	502			
16	Total for Quarter 4				16,859	1,299	1,506			
17	Total Year to Date/Year				78,062	5,791	6,024			

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 400 Line No.: 1 Column: a

The Northern States Power Co. Integrated System refers to the interconnected production and transmission facilities of both Northern States Power Co. (a Minnesota corporation) which has customers in Minnesota, North Dakota and South Dakota, and Northern States Power Co. (a Wisconsin corporation) which has customers in Michigan and Wisconsin (collectively, the "NSP Companies"). The construction, operation and maintenance of the two companies' systems is coordinated.

Schedule Page: 400 Line No.: 1 Column: e

"Firm Network Service - For Self" includes load in the Otter Tail Power Balancing Authority (OTP BA). The NSP Companies' load in the OTP BA at the OTP coincident peak is:

January	348
February	347
March	329
April	248
May	245
June	314
July	343
August	358
September	368
October	254
November	281
December	291
	<u>3,726</u>

"Firm Network Service - For Self" does not include the NSP Companies' load on transmission assets in the Great River Energy Balancing Authority (GRE BA). The NSP Companies' load in the GRE BA at the Great River Energy coincident peak is:

January	76
February	62
March	68
April	48
May	57
June	63
July	79
August	84
September	51
October	55
November	62
December	69
	<u>774</u>

Schedule Page: 400 Line No.: 1 Column: f

"Firm Network Service - For Others" does not include the load of Great River Energy (GRE), Southern Minnesota Municipal Power Agency (SMPA), or Missouri River Energy Services (MRES) City of Marshall Load in the NSP Companies' Midwest ISO Pricing Zone. The GRE, SMPA and MRES City of Marshall network load not included in column (f) is:

	GRE	SMPA	MRES
January	664	125	81
February	677	117	81
March	651	113	81
April	513	105	75

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/11/2016	2015/Q4
FOOTNOTE DATA			

May	635	113	76
June	799	138	82
July	720	157	84
August	953	155	82
September	846	155	82
October	531	109	75
November	677	110	73
December	653	118	71
	8,319	1,515	943

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.

(2) Report on Column (b) by month the transmission system's peak load.

(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).

(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).

(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:										
Line No.	Month	Monthly Peak MW - Total	Day of Monthly Peak	Hour of Monthly Peak	Imports into ISO/RTO	Exports from ISO/RTO	Through and Out Service	Network Service Usage	Point-to-Point Service Usage	Total Usage
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of <u>2015/Q4</u>

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: Northern States Power Co. Integrated System

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	4,082,235	403,031	5,578	7	1800
30	February	3,748,270	349,075	5,419	18	1900
31	March	3,726,848	385,306	5,212	4	2000
32	April	3,307,114	220,040	4,716	9	1200
33	May	3,500,976	273,008	5,573	28	1600
34	June	3,815,295	296,450	6,728	9	1700
35	July	4,482,475	347,549	7,137	27	1700
36	August	4,183,630	367,658	7,298	14	1600
37	September	4,109,937	484,068	7,112	3	1700
38	October	3,788,133	620,300	4,730	28	1900
39	November	3,649,981	424,605	5,035	30	1800
40	December	4,035,866	693,338	5,177	17	1800
41	TOTAL	46,430,760	4,864,428			

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 401 Line No.: 10 Column: b

Includes 659 mWH purchased for energy storage operation.

Schedule Page: 401 Line No.: 27 Column: b

MWH stored in Wind2Battery project on Dec. 31, 2015

0.200

Schedule Page: 401 Line No.: 29 Column: Sys

The Northern States Power Co. Integrated System refers to the interconnected production and transmission facilities of both Northern States Power Co. (a Minnesota corporation) which has customers in Minnesota, North Dakota and South Dakota, and Northern States Power Co. (a Wisconsin corporation) which has customers in Michigan and Wisconsin. The construction, operation and maintenance of the two companies' systems is coordinated. This table shows the integrated system peak and the demand of each jurisdiction at the time of the integrated system peak. The monthly peaks reported in column d of page 401b are the sums of the monthly peaks for the states of Minnesota, North Dakota and South Dakota shown below.

Day	Hour	Integrated System	Northern States Power Co. (a Minnesota corporation)			Northern States Power Co. (a Wisconsin corporation)	
			Minnesota	North Dakota	South Dakota	Wisconsin	Michigan
7-Jan	1800	6,739	4,840	407	331	1,135	26
18-Feb	1900	6,541	4,698	406	315	1,095	27
4-Mar	2000	6,279	4,504	395	313	1,044	23
9-Apr	1200	5,670	4,162	279	275	933	21
28-May	1600	6,583	4,921	334	318	990	20
9-Jun	1700	7,827	5,917	375	436	1,080	19
27-Jul	1700	8,426	6,252	432	453	1,267	22
14-Aug	1600	8,621	6,398	447	453	1,299	24
3-Sep	1700	8,302	6,202	451	459	1,166	24
28-Oct	1900	5,646	4,151	307	272	898	18
30-Nov	1800	5,994	4,414	317	304	939	20
17-Dec	1800	6,196	4,503	366	308	995	24

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016		Year/Period of Report End of 2015/Q4	
STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)							
1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a term basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.							
Line No.	Item (a)	Plant Name: <i>Riverside</i> (b)			Plant Name: <i>Wilmarth</i> (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Combined Cycle			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1911			1948		
4	Year Last Unit was Installed	2009			1951		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	585.90			25.00		
6	Net Peak Demand on Plant - MW (60 minutes)	537			19		
7	Plant Hours Connected to Load	6340			7930		
8	Net Continuous Plant Capability (Megawatts)	487			18		
9	When Not Limited by Condenser Water	487			18		
10	When Limited by Condenser Water	470			18		
11	Average Number of Employees	25			27		
12	Net Generation, Exclusive of Plant Use - KWh	2642154031			108449967		
13	Cost of Plant: Land and Land Rights	450132			499773		
14	Structures and Improvements	52226101			8063468		
15	Equipment Costs	251143648			45082492		
16	Asset Retirement Costs	819093			1307372		
17	Total Cost	304638974			54953105		
18	Cost per KW of Installed Capacity (line 17/5) Including	519.9505			2198.1242		
19	Production Expenses: Oper, Supv, & Engr	454036			211522		
20	Fuel	76591609			2725075		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	11923			1552943		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2103449			126474		
26	Misc Steam (or Nuclear) Power Expenses	738851			739208		
27	Rents	442919			171583		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	303038			26794		
30	Maintenance of Structures	899877			168236		
31	Maintenance of Boiler (or reactor) Plant	117			1972358		
32	Maintenance of Electric Plant	2450509			215776		
33	Maintenance of Misc Steam (or Nuclear) Plant	400904			683387		
34	Total Production Expenses	84397232			8593356		
35	Expenses per Net KWh	0.0319			0.0792		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Gas	Oil	RDF	Gas	Wood
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		MCF	Barrels	Tons	MCF	Tons
38	Quantity (Units) of Fuel Burned	0	17875949	19	189792	28878	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1061	138365	6026	1063	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	4.284	58.964	2.019	6.143	0.000
41	Average Cost of Fuel per Unit Burned	0.000	4.284	58.964	15.560	6.143	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	4.038	10.146	1.291	5.779	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.029	0.000	0.000	0.030	0.000
44	Average BTU per KWh Net Generation	0.000	7207.930	0.000	0.000	21373.850	0.000

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016		Year/Period of Report End of 2015/Q4	
STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)							
1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a term basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.							
Line No.	Item (a)	Plant Name: Sherburne County (b)			Plant Name: Granite City (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Ind Enclosures		
3	Year Originally Constructed	1976			1969		
4	Year Last Unit was Installed	1987			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2469.32			72.00		
6	Net Peak Demand on Plant - MW (60 minutes)	1926			29		
7	Plant Hours Connected to Load	8760			26		
8	Net Continuous Plant Capability (Megawatts)	1879			64		
9	When Not Limited by Condenser Water	1879			64		
10	When Limited by Condenser Water	1879			52		
11	Average Number of Employees	267			0		
12	Net Generation, Exclusive of Plant Use - KWh	10219972811			-216560		
13	Cost of Plant: Land and Land Rights	5951721			40240		
14	Structures and Improvements	225239423			1241718		
15	Equipment Costs	1184753817			7525213		
16	Asset Retirement Costs	5309851			0		
17	Total Cost	1421254812			8807171		
18	Cost per KW of Installed Capacity (line 17/5) Including	575.5653			122.3218		
19	Production Expenses: Oper, Supv, & Engr	3410882			13243		
20	Fuel	248119281			25419		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	7217296			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2984356			48775		
26	Misc Steam (or Nuclear) Power Expenses	14871487			2341		
27	Rents	1351100			4252		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1707112			9429		
30	Maintenance of Structures	2866283			19817		
31	Maintenance of Boiler (or reactor) Plant	18557563			0		
32	Maintenance of Electric Plant	10204563			14698		
33	Maintenance of Misc Steam (or Nuclear) Plant	7875250			1059		
34	Total Production Expenses	319165173			139033		
35	Expenses per Net KWh	0.0312			-0.6420		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal		Oil	Gas		Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons		Barrels	MCF		Barrels
38	Quantity (Units) of Fuel Burned	6152312	0	22811	4684	0	36
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8707	0	138200	1000	0	138907
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	38.716	0.000	48.359	4.913	0.000	66.501
41	Average Cost of Fuel per Unit Burned	40.453	0.000	48.359	4.913	0.000	66.501
42	Average Cost of Fuel Burned per Million BTU	2.323	0.000	8.331	4.913	0.000	11.399
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.020	0.000	0.000	-0.120	0.000
44	Average BTU per KWh Net Generation	0.000	10495.520	0.000	0.000	-22662.040	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)							
1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a term basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.							
Line No.	Item (a)	Plant Name: <i>Angus Anson</i> (b)			Plant Name: <i>Black Dog Unit 2 & 5</i> (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbines			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)				Conventional		
3	Year Originally Constructed	1994			1987		
4	Year Last Unit was Installed	2005			2002		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	405.66			324.79		
6	Net Peak Demand on Plant - MW (60 minutes)	331			329		
7	Plant Hours Connected to Load	949			3937		
8	Net Continuous Plant Capability (Megawatts)	386			298		
9	When Not Limited by Condenser Water	386			298		
10	When Limited by Condenser Water	327			282		
11	Average Number of Employees	9			30		
12	Net Generation, Exclusive of Plant Use - KWh	103037508			879478004		
13	Cost of Plant: Land and Land Rights	1172616			952692		
14	Structures and Improvements	7692388			46893527		
15	Equipment Costs	114511221			173192031		
16	Asset Retirement Costs	577112			29536202		
17	Total Cost	123953337			250574452		
18	Cost per KW of Installed Capacity (line 17/5) Including	305.5597			771.4968		
19	Production Expenses: Oper, Supv, & Engr	19049			59870		
20	Fuel	6849252			24345379		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	178748			1203797		
26	Misc Steam (or Nuclear) Power Expenses	554425			66125		
27	Rents	77041			138990		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	11534			53373		
30	Maintenance of Structures	712002			301448		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	674988			1321205		
33	Maintenance of Misc Steam (or Nuclear) Plant	33487			92266		
34	Total Production Expenses	9110526			27582453		
35	Expenses per Net KWh	0.0884			0.0314		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas		Oil		Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF		Barrels		MCF	
38	Quantity (Units) of Fuel Burned	1015713	0	28492	0	6163021	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1067	0	138411	0	1058	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.611	0.000	102.431	0.000	3.950	0.000
41	Average Cost of Fuel per Unit Burned	3.611	0.000	102.431	0.000	3.950	0.000
42	Average Cost of Fuel Burned per Million BTU	3.384	0.000	17.620	0.000	3.733	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.060	0.000	0.000	0.030	0.000
44	Average BTU per KWh Net Generation	0.000	12128.920	0.000	0.000	7416.080	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)							
1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a term basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.							
Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)(Continued)									
9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.									
Plant Name: A S King (d)			Plant Name: Prairie Island (e)			Plant Name: Blue Lake (f)			Line No.
Steam			Nuclear			Gas Turbine			1
Conventional			Conventional			Ind Enclosures			2
1968			1973			1974			3
1968			1974			2005			4
598.40			1186.20			559.32			5
535			1109			398			6
6988			8760			1701			7
511			1092			545			8
511			1092			545			9
511			1040			453			10
88			673			5			11
3017879500			7374711000			69277000			12
1335100			361732			141878			13
38596792			302394576			1632060			14
649809653			1624594259			95057710			15
5096710			174529690			0			16
694838255			2101880257			96831648			17
1161.1602			1771.9442			173.1239			18
1039419			40006456			91743			19
70903126			65033219			4458315			20
0			4527336			0			21
7143543			27619391			0			22
0			0			0			23
0			0			0			24
909897			2181969			207100			25
3246298			78156514			176745			26
835855			6170870			97618			27
0			0			0			28
449022			4366565			42043			29
1969765			685835			174466			30
11043301			22836604			0			31
1976748			14996893			567250			32
3759532			31861122			7331			33
103276506			298442774			5822611			34
0.0342			0.0405			0.0840			35
Coal	Gas	Oil		Nuclear		Gas		Oil	36
Tons	MCF	Barrels		Grams: U235		MCF		Barrels	37
1691743	41256	43	0	711113	0	743549	0	3839	38
8796	1056	138889	0	110643	0	1060	0	137996	39
38.498	10.203	130.341	0.000	0.000	0.000	5.478	0.000	100.397	40
41.736	10.203	130.341	0.000	0.000	0.000	5.478	0.000	100.397	41
2.372	9.659	22.344	0.000	0.833	0.000	5.165	0.000	17.322	42
0.000	0.020	0.000	0.000	0.010	0.000	0.000	0.060	0.000	43
0.000	9876.640	0.000	0.000	10669.310	0.000	0.000	11703.340	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)(Continued)									
9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.									
Plant Name: <i>Inver Hills</i> (d)			Plant Name: <i>High Bridge 7, 8, 9</i> (e)			Plant Name: <i>Monticello</i> (f)		Line No.	
Gas Turbine			Combined Cycle			Nuclear		1	
Ind Enclosures			Conventional			Conventional		2	
1972			1924			1971		3	
1972			2008			1971		4	
280.50			644.06			684.97		5	
236			596			670		6	
1597			5207			7412		7	
371			610			635		8	
371			610			635		9	
282			534			607		10	
7			25			525		11	
5716222			1938831000			4663895000		12	
432561			528150			783302		13	
1417386			70886707			194617546		14	
57381458			317599631			1140387970		15	
0			0			308141112		16	
59231405			389014488			1643929930		17	
211.1637			604.0035			2400.0028		18	
3350			435965			28878204		19	
840463			50556731			41391184		20	
0			0			4030933		21	
0			0			20939534		22	
0			0			0		23	
0			0			0		24	
214351			2577568			0		25	
69368			1510011			59530155		26	
45509			404886			4413624		27	
0			0			0		28	
4341			315059			3964930		29	
182106			862964			0		30	
0			0			16107496		31	
608030			1582553			4569999		32	
9835			137506			12542890		33	
1977353			58383243			196368949		34	
0.3459			0.0301			0.0421		35	
	Gas	Oil		Gas			Nuclear		36
	MCF	Barrels		MCF			Grams: U235		37
0	119970	4266	0	12893336	0	0	456419	0	38
0	1058	134536	0	1060	0	0	107126	0	39
0.000	4.114	79.860	0.000	3.921	0.000	0.000	0.000	0.000	40
0.000	4.114	81.498	0.000	3.921	0.000	0.000	0.000	0.000	41
0.000	3.887	14.423	0.000	3.701	0.000	0.000	0.853	0.000	42
0.000	0.150	0.000	0.000	0.030	0.000	0.000	0.010	0.000	43
0.000	26422.110	0.000	0.000	7046.550	0.000	0.000	10475.480	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)(Continued)									
9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.									
Plant Name: <i>Black Dog 3 & 4</i> (d)			Plant Name: <i>Key City</i> (e)			Plant Name: (f)			Line No.
Steam			Gas Turbine						1
Conventional			Ind Enclosures						2
1952			1970						3
1960			1970						4
276.84			72.00			0.00			5
237			0			0			6
2447			0			0			7
215			41			0			8
215			41			0			9
215			34			0			10
0			0			0			11
373411826			-740480			0			12
0			67495			0			13
0			1002265			0			14
0			7597648			0			15
0			0			0			16
0			8667408			0			17
0.0000			120.3807			0			18
527824			0			0			19
9956251			4104			0			20
0			0			0			21
2440052			0			0			22
0			0			0			23
0			0			0			24
432893			0			0			25
1046775			0			0			26
325342			799			0			27
0			0			0			28
131131			0			0			29
1451830			3104			0			30
784518			0			0			31
330785			9390			0			32
1388589			0			0			33
18815990			17397			0			34
0.0504			-0.0235			0.0000			35
Coal	Gas	Oil							36
Tons	MCF	Barrels							37
228280	69200	25	0	0	0	0	0	0	38
8948	1051	139813	0	0	0	0	0	0	39
38.574	4.860	113.599	0.000	0.000	0.000	0.000	0.000	0.000	40
45.441	4.860	113.599	0.000	0.000	0.000	0.000	0.000	0.000	41
2.539	4.622	19.345	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	11136.110	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)(Continued)									
9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.									
Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 403 Line No.: -1 Column: e

Instruction 12 - Prairie Island Nuclear Generating Plant (p. 403)

(a) Operating and maintenance costs of the Prairie Island Plant are expensed as incurred. NSP-Minnesota uses a deferral and amortization method for nuclear refueling operation and maintenance costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric cases.

(b) NSP-Minnesota buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.

(c) The Prairie Island Plant has two identical Westinghouse 2 loop PWR Nuclear Power Plants. Fuel material is UO₂ contained in zirconium alloy based cladding. The equilibrium cycle has approximately 47 metric tons of uranium metal with a nominal U-235 enrichment of 4.95 weight percent in the fresh fuel. The reactor is licensed to operate at 1677 Mwt.

Schedule Page: 402.1 Line No.: -1 Column: b

Sherburne County Generating Plant Unit 3 is jointly owned by NSP-Minnesota (59 percent) and Southern Minnesota Municipal Power Agency (41 percent). See Note 4 of the Financial Statements on Page 123 for disclosures regarding Sherco Unit 3.

Schedule Page: 403.1 Line No.: -1 Column: f

Instruction 12 - Monticello Nuclear Generating Plant (p. 403.1)

(a) Operating and maintenance costs of the Monticello Plant are expensed as incurred. NSP-Minnesota uses a deferral and amortization method for nuclear refueling operation and maintenance costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric cases.

(b) NSP-Minnesota buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.

(c) The Monticello Plant is a General Electric BWR-3 Nuclear Power Plant. Fuel material is UO₂ contained in zirconium alloy based cladding. The equilibrium cycle has approximately 84 metric tons of uranium metal with a nominal U-235 enrichment of 3.8 weight percent in the fresh fuel. The reactor is licensed to operate at 2,004 Mwt.

Schedule Page: 402 Line No.: 39 Column: b1

The "Average Heat Content of Fuel Burned" is calculated as:

Coal: Btu/pound
Oil: Btu/gallons
Gas: Btu/cubic ft

Schedule Page: 402 Line No.: 39 Column: e2

Average heat content of fuel burned is in MBTU/kg U235.

Schedule Page: 402.1 Line No.: 39 Column: f2

Average heat content of fuel burned is in KBTU/gm U235.

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of <u>2015/Q4</u>
HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)					
1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings) 2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number. 3. If net peak demand for 60 minutes is not available, give that which is available specifying period. 4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.					
Line No.	Item (a)	FERC Licensed Project No. 2056 Plant Name: Henn Is & Upper Dam (b)	FERC Licensed Project No. 0 Plant Name: (c)		
1	Kind of Plant (Run-of-River or Storage)	Run of River			
2	Plant Construction type (Conventional or Outdoor)	Conventional			
3	Year Originally Constructed	1908			
4	Year Last Unit was Installed	1955			
5	Total installed cap (Gen name plate Rating in MW)	13.89	0.00		
6	Net Peak Demand on Plant-Megawatts (60 minutes)	12	0		
7	Plant Hours Connect to Load	8,513	0		
8	Net Plant Capability (in megawatts)				
9	(a) Under Most Favorable Oper Conditions	7	0		
10	(b) Under the Most Adverse Oper Conditions	6	0		
11	Average Number of Employees	2	0		
12	Net Generation, Exclusive of Plant Use - Kwh	78,859,782	0		
13	Cost of Plant				
14	Land and Land Rights	1,548,707	0		
15	Structures and Improvements	1,349,723	0		
16	Reservoirs, Dams, and Waterways	8,537,091	0		
17	Equipment Costs	13,356,793	0		
18	Roads, Railroads, and Bridges	0	0		
19	Asset Retirement Costs	0	0		
20	TOTAL cost (Total of 14 thru 19)	24,792,314	0		
21	Cost per KW of Installed Capacity (line 20 / 5)	1,784.9038	0.0000		
22	Production Expenses				
23	Operation Supervision and Engineering	0	0		
24	Water for Power	0	0		
25	Hydraulic Expenses	0	0		
26	Electric Expenses	0	0		
27	Misc Hydraulic Power Generation Expenses	0	0		
28	Rents	0	0		
29	Maintenance Supervision and Engineering	0	0		
30	Maintenance of Structures	0	0		
31	Maintenance of Reservoirs, Dams, and Waterways	0	0		
32	Maintenance of Electric Plant	0	0		
33	Maintenance of Misc Hydraulic Plant	0	0		
34	Total Production Expenses (total 23 thru 33)	0	0		
35	Expenses per net KWh	0.0000	0.0000		

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of <u>2015/Q4</u>
HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)					
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."					
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.					
FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.		
			1		
			2		
			3		
			4		
0.00	0.00	0.00	5		
0	0	0	6		
0	0	0	7		
			8		
0	0	0	9		
0	0	0	10		
0	0	0	11		
0	0	0	12		
			13		
0	0	0	14		
0	0	0	15		
0	0	0	16		
0	0	0	17		
0	0	0	18		
0	0	0	19		
0	0	0	20		
0.0000	0.0000	0.0000	21		
			22		
0	0	0	23		
0	0	0	24		
0	0	0	25		
0	0	0	26		
0	0	0	27		
0	0	0	28		
0	0	0	29		
0	0	0	30		
0	0	0	31		
0	0	0	32		
0	0	0	33		
0	0	0	34		
0.0000	0.0000	0.0000	35		

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of <u>2015/Q4</u>
PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)					
1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings) 2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number. 3. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant. 5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."					
Line No.	Item (a)	FERC Licensed Project No. Plant Name:		0 (b)	
1	Type of Plant Construction (Conventional or Outdoor)				
2	Year Originally Constructed				
3	Year Last Unit was Installed				
4	Total installed cap (Gen name plate Rating in MW)				
5	Net Peak Demand on Plant-Megawatts (60 minutes)				
6	Plant Hours Connect to Load While Generating				
7	Net Plant Capability (in megawatts)				
8	Average Number of Employees				
9	Generation, Exclusive of Plant Use - Kwh				
10	Energy Used for Pumping				
11	Net Output for Load (line 9 - line 10) - Kwh				
12	Cost of Plant				
13	Land and Land Rights				
14	Structures and Improvements				
15	Reservoirs, Dams, and Waterways				
16	Water Wheels, Turbines, and Generators				
17	Accessory Electric Equipment				
18	Miscellaneous Powerplant Equipment				
19	Roads, Railroads, and Bridges				
20	Asset Retirement Costs				
21	Total cost (total 13 thru 20)				
22	Cost per KW of installed cap (line 21 / 4)				
23	Production Expenses				
24	Operation Supervision and Engineering				
25	Water for Power				
26	Pumped Storage Expenses				
27	Electric Expenses				
28	Misc Pumped Storage Power generation Expenses				
29	Rents				
30	Maintenance Supervision and Engineering				
31	Maintenance of Structures				
32	Maintenance of Reservoirs, Dams, and Waterways				
33	Maintenance of Electric Plant				
34	Maintenance of Misc Pumped Storage Plant				
35	Production Exp Before Pumping Exp (24 thru 34)				
36	Pumping Expenses				
37	Total Production Exp (total 35 and 36)				
38	Expenses per KWh (line 37 / 9)				

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of <u>2015/Q4</u>
PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)					
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes. 7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.					
FERC Licensed Project No. Plant Name: (c)	0	FERC Licensed Project No. Plant Name: (d)	0	FERC Licensed Project No. Plant Name: (e)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
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					10
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					37
					38

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	STEAM PLANT					
2						
3	Red Wing	1949	23.00	21.0	117,492,826	63,387,375
4	Minnesota Valley	1932				13,510,516
5	High Bridge 5 & 6	1924				
6						
7						
8	GAS PLANT					
9						
10	West Faribault	1965				
11						
12						
13	INTERNAL COMBUSTION					
14						
15	Dispersed Generation				-235,538	2,499,099
16						
17						
18	WIND TURBINE PLANTS					
19						
20	Lake Benton	1997				10,190,362
21	Grand Meadow Wind Farm	2008	100.50	100.0	334,806,710	220,198,879
22	Nobles Wind	2010	201.00	202.0	740,612,852	537,224,696
23	Pleasant Valley	2015	200.00	187.0	96,120,617	351,099,114
24	Borders Wind	2015	150.00	144.0	31,559,941	271,006,263
25						
26	SOLAR					
27						
28	Photovoltaic Units	1995				306,139
29						
30						
31						
32						
33						
34						
35						
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46						

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4	
GENERATING PLANT STATISTICS (Small Plants) (Continued)						
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.						
Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
						2
2,755,973	2,395,890	2,778,860	4,755,548	RDF, Gas	129	3
	21,553		20,045			4
	96,356		88,048			5
						6
						7
						8
						9
	40					10
						11
						12
						13
						14
	60	16,241	10,012	Oil	1,610	15
						16
						17
						18
						19
				Wind		20
2,191,034	1,271,225		1,464,231	Wind		21
2,672,760	2,830,849		1,489,071	Wind		22
1,755,496	357,340		339,561	Wind		23
1,806,708	304,408		198,667	Wind		24
						25
						26
						27
				Solar		28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 410 Line No.: 1 Column: g
The Plant Cost is manually calculated (not calculated by the FERC software) - (col g = col f / col c)

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS

- Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
- Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
- Report data by individual lines for all voltages if so required by a State commission.
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
- Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	(5702) FORBES	MANITOBA HYDRO	500.00	500.00	TOWER	203.80		1
2	(5703) CHISAGO COUNTY	GRE INTERCONNECTION	500.00	500.00	TOWER	61.46		1
3	(0953) SPLIT ROCK	LAKEFIELD JUNCTION	345.00	345.00	SINGLE POLE	22.67		1
4			345.00	345.00	SINGLE POLE	4.43		1
5			345.00	345.00	SINGLE POLE	60.85		1
6			345.00	345.00	TOWER	0.22		1
7	(0954) QUARRY	ALEXANDRIA SWITCHING	345.00	345.00	2 POLE	2.14		1
8			345.00	345.00	SINGLE POLE	63.89		1
9			345.00	345.00	SPECIAL 2	15.19		1
10	(0955) ALEXANDRIA SW.	BISON	345.00	345.00	2 POLE	14.68		1
11			345.00	345.00	SINGLE POLE	113.93		1
12			345.00	345.00	SPECIAL 1	3.99		1
13			345.00	345.00	SPECIAL 2	6.18		1
14	(0956) LYON COUNTY	CEDAR MOUNTAIN (LINE #1)	345.00	345.00	SINGLE POLE	49.49		1
15	(0957) LYON COUNTY	CEDAR MOUNTAIN (LINE #2)	345.00	345.00	SINGLE POLE		49.49	1
16	(0958) CEDAR MOUNTAIN	HELENA	345.00	345.00	SINGLE POLE	73.10		1
17	(0959) CEDAR MOUNTAIN	HELENA	345.00	345.00	SINGLE POLE		73.06	1
18	(0960) HELENA	CHUB LAKE	345.00	345.00	SINGLE POLE	20.87		1
19	(0961) CHUB LAKE (GRE)	HAMPTON	345.00	345.00	SINGLE POLE	18.10		1
20	(0962) LYON COUNTY	HAZEL CREEK	345.00	345.00	SINGLE POLE	24.54		1
21	(0965) NORTH ROCHESTER	MISSISSIPPI RIVER	345.00	345.00	SINGLE POLE	32.20		1
22			345.00	345.00	SPECIAL 2	3.12		1
23			345.00	345.00	SPECIAL 3	8.03		1
24	(0970) BROOKINGS	WHITE(WAPA)#1	345.00	345.00	SINGLE POLE	0.38		1
25	(0971) BROOKINGS	WHITE(WAPA)#1	345.00	345.00	SINGLE POLE	0.42		1
26	(0972) BROOKINGS	LYON COUNTY	345.00	345.00	SINGLE POLE	59.30		1
27	(0973) MONTICELLO	QUARRY	345.00	345.00	SINGLE POLE	30.04		1
28	(0974) WILMARTH	CALPINE GENERATOR	345.00	345.00	SINGLE POLE	0.22		1
29	(0975) KING	RED ROCK	345.00	345.00	K-FRAME	3.54		1
30			345.00	345.00	TOWER	21.80		1
31	(0976) PARKERS LAKE	PRAIRIE ISLAND	345.00	345.00	K-FRAME	19.08		1
32			345.00	345.00	K-FRAME	6.16		1
33			345.00	345.00	SINGLE POLE	7.48		1
34			345.00	345.00	TOWER	34.87		1
35	(0977) KING	TERMINAL	345.00	345.00	SINGLE POLE	2.82		1
36					TOTAL	5,004.18	549.03	121

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS

- Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
- Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
- Report data by individual lines for all voltages if so required by a State commission.
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
- Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1			345.00	345.00	TOWER	20.00		1
2	(0978) MONTICELLO	PARKERS LAKE	345.00	345.00	H-FRAME	7.16		1
3			345.00	345.00	K-FRAME	13.13		1
4			345.00	345.00	SINGLE POLE	0.59		1
5			345.00	345.00	TOWER	16.28		1
6	(0979) PRAIRIE ISLAND	ADAMS	345.00	345.00	H-FRAME	18.40		1
7			345.00	345.00	K-FRAME	55.47		1
8			345.00	345.00	TOWER	2.40		1
9	(0980) CHISAGO COUNTY	COON CREEK	345.00	345.00	SINGLE POLE	4.61	2.82	1
10			345.00	345.00	SINGLE POLE	26.11		1
11			345.00	345.00	TOWER	6.87	11.30	1
12			345.00	345.00	TOWER	5.27	0.55	1
13	(0981) KING	ST. CROIX RIVER (EAU	345.00	345.00	K-FRAME	3.69		1
14			345.00	345.00	TOWER	0.72	15.19	1
15	(0982) BLUE LAKE	LAKEFIELD JUNCTION	345.00	345.00	H-FRAME	9.95		1
16			345.00	345.00	K-FRAME	105.78		1
17			345.00	345.00	SINGLE POLE	0.48		1
18			345.00	345.00	TOWER	14.59		1
19	(0984) SHERBURNE	TERMINAL	345.00	345.00	K-FRAME	19.79		1
20			345.00	345.00	SINGLE POLE		4.61	1
21			345.00	345.00	SINGLE POLE	14.81		1
22			345.00	345.00	TOWER		9.02	1
23			345.00	345.00	TOWER	8.84		1
24	(0985) SHERBURNE	GRE CONNECTION	345.00	345.00	H-FRAME	7.07		1
25			345.00	345.00	K-FRAME	12.85	1.63	1
26			345.00	345.00	TOWER	5.79	5.79	1
27	(0986) PRAIRIE ISLAND	RED ROCK (LINE #2)	345.00	345.00	K-FRAME	21.20	0.03	1
28			345.00	345.00	SINGLE POLE	5.91		1
29			345.00	345.00	TOWER	2.25		1
30			345.00	345.00	TOWER	0.12	2.40	1
31	(0987) PRAIRIE ISLAND	RED ROCK (LINE #1)	345.00	345.00	K-FRAME	18.32		1
32			345.00	345.00	SINGLE POLE	2.35	6.50	1
33			345.00	345.00	TOWER		2.25	1
34			345.00	345.00	TOWER	0.15	2.37	1
35	(0988) BLUE LAKE	PARKERS LAKE	345.00	345.00	SINGLE POLE		2.11	1
36					TOTAL	5,004.18	549.03	121

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS

- Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
- Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
- Report data by individual lines for all voltages if so required by a State commission.
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
- Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1			345.00	345.00	TOWER		12.67	1
2	(0989) BLUE LAKE	RED ROCK	345.00	345.00	H-FRAME	0.88		1
3			345.00	345.00	K-FRAME	2.77		1
4			345.00	345.00	SINGLE POLE		0.83	1
5			345.00	345.00	TOWER	9.12	17.16	1
6	(0991) SHERBURNE	MONTICELLO	345.00	345.00	TOWER		5.81	1
7	(0992) SHERBURNE	COON CREEK	345.00	345.00	K-FRAME	16.93	0.66	1
8			345.00	345.00	SINGLE POLE		14.18	1
9			345.00	345.00	TOWER		11.62	1
10	(0994) CHISAGO COUNTY	KING	345.00	345.00	SINGLE POLE		26.11	1
11			345.00	345.00	TOWER		5.51	1
12			345.00	345.00	TOWER		1.11	1
13			345.00	345.00	TOWER		5.45	1
14	(0996) PARKERS LAKE	DICKINSON	345.00	345.00	TOWER	0.13	9.62	1
15	(0997) SPLIT ROCK	WATERTOWN	345.00	345.00	SINGLE POLE	4.46		1
16			345.00	345.00	TOWER	0.45	0.24	1
17	(0998) SPLIT ROCK	SIOUX CITY	345.00	345.00	SINGLE POLE		0.63	1
18			345.00	345.00	SINGLE POLE		4.43	1
19	(0900) BLUE LAKE	GRANITE FALLS (WAPA)	230.00	230.00	H-FRAME	1.35		1
20			230.00	230.00	K-FRAME	2.41		1
21			230.00	230.00	SINGLE POLE	0.73		1
22			230.00	230.00	TOWER	102.92	0.34	1
23	(0902) LINE 0921 CON HWY	MP INTER. (ARROWHEAD)	230.00	230.00	K-FRAME	66.46		1
24	(0909) AUDUBON (OTTER	HUBBARD	230.00	230.00	H-FRAME	38.54		1
25	(0910) MAPLE RIVER	WAHPETON (MINNKOTA)	230.00	230.00	TOWER	3.59		1
26	(0911) MAPLE RIVER	AUDUBON	230.00	230.00	H-FRAME	4.20		1
27			230.00	230.00	TOWER	0.03	3.72	1
28	(0912) DRAYTON	LETELLIER	230.00	230.00	H-FRAME	28.73		1
29	(0915) SHEYENNE	FARGO (WAPA)	230.00	230.00	H-FRAME	3.95		1
30			230.00	230.00	TOWER	0.03	0.19	1
31	(0916) PRAIRIE (MPC)	GRAND FORKS (WAPA)	230.00	230.00	H-FRAME	6.82		1
32	(0918) SPLIT ROCK	SIOUX FALLS (WAPA)	230.00	230.00	SINGLE POLE	0.96		1
33	(0919) PAYNESVILLE	WILLMAR	230.00	230.00	H-FRAME	2.49		1
34			230.00	230.00	SINGLE POLE	27.24		1
35	(0920) RUGBY	GLENBORO	230.00	230.00	H-FRAME	56.50		1
36					TOTAL	5,004.18	549.03	121

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	(0920) RUGBY	GLENBORO	230.00	230.00	SPECIAL 1	0.15		1
2	(0921) RED ROCK	LINE 0902 CONN (HWY 36)	230.00	230.00	K-FRAME	10.92	0.09	1
3			230.00	230.00	TOWER	2.78		1
4	(0922) CASS LAKE	BOSWELL	230.00	230.00	H-FRAME	51.46		1
5	(0923) CASS LAKE	WILTON	230.00	230.00	H-FRAME	19.32		1
6	(0963) HAZEL CREEK	MINNESOTA VALLEY	230.00	345.00	SINGLE POLE	4.97		1
7	(5300) SOUTH BEND	WINNEBAGO (ALLIANT	161.00	161.00	H-FRAME	29.46		1
8			161.00	161.00	SINGLE POLE	0.65		1
9	(5301) SPLIT ROCK	MAGNOLIA (ALLIANT	161.00	161.00	H-FRAME	18.79		1
10			161.00	161.00	SINGLE POLE	0.87		1
11			161.00	161.00	SINGLE POLE	0.41		1
12	(5305) LAWRENCE CREEK	ST. CROIX RIVER (SCF)	161.00	161.00	SINGLE POLE	1.57		1
13			161.00	161.00	UNDERGROU	0.58		1
14	(5306) PLEASANT VALLEY	BYRON	161.00	161.00	SINGLE POLE	16.60		1
15	(5310) NORTH ROCHESTER	NORTHERN HILLS	161.00	161.00	SINGLE POLE	15.12		1
16			161.00	161.00	Y-FRAME	0.39		1
17								
18	Summary of 115 kV System		115.00	115.00	Overhead	1,460.85	122.77	
19			115.00	115.00	Underground	13.02		
20	Summary of 69 kV System		69.00	69.00	Overhead	1,492.42	84.38	
21			69.00	69.00	Underground	1.62		
22	Summary of 34.5 kV System		34.00	34.00	Overhead	60.05	32.39	
23			34.00	34.00	Underground	0.55		
24	All lines							
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	5,004.18	549.03	121

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
9-1192 kcmil ACSR	1,723,334	65,307,062	67,030,396					1
9-1192 kcmil ACSR	2,237,403	15,571,270	17,808,674					2
6-397.5 ACSR	7,693,156	121,665,104	129,358,260					3
6-954 kcmil ACSR								4
6-954 ACSS/TW								5
6-954 ACSS/TW								6
6-954 ACSS/TW	4,188,381	66,080,134	70,268,515					7
6-954 ACSS/TW								8
6-954 ACSS/TW								9
6-954 ACSS/TW	7,801,660	106,494,250	114,295,910					10
6-954 ACSS/TW								11
6-954 ACSS/TW								12
6-954 ACSS/TW								13
6-954 ACSS/TW	600,490		600,490					14
6-954 ACSS/TW	4,894,568	65,839,990	70,734,558					15
6-954 ACSS/TW	730,515		730,515					16
6-954 ACSS/TW	8,996,117	112,135,762	121,131,880					17
6-954 ACSS/TW	5,088,059	36,151,383	41,239,442					18
6-954 ACSS/TW	6,358,912	37,681,201	44,040,113					19
6-954 ACSS/TW	73,757	27,002,133	27,075,890					20
6-954 ACSS/TW	3,747,000	61,234,196	64,981,197					21
6-954 ACSS/TW								22
6-954 ACSS/TW								23
6-795 kcmil ACSS		1,215,849	1,215,849					24
6-795 kcmil ACSS	13,748	933,240	946,988					25
6-954 ACSS/TW	582,207	76,846,400	77,428,607					26
6-954 ACSS/TW	5,001,569	10,969,295	15,970,864					27
6-795 kcmil ACSR		888,655	888,655					28
6-795 kcmil ACSR	401,128	2,587,137	2,988,265					29
6-795 kcmil ACSR								30
6-795 kcmil ACSR	2,319,556	12,563,142	14,882,698					31
6-954 kcmil ACSR								32
6-795 kcmil ACSR								33
6-795 kcmil ACSR								34
6-795 kcmil ACSR	2,273,876	4,469,860	6,743,736					35
	105,408,892	1,866,079,632	1,971,488,529	1,780,386	6,929,875	2,190,831	10,901,092	36

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
6-795 kcmil ACSR								1
6-954 kcmil ACSR	882,197	7,822,817	8,705,014					2
6-954 kcmil ACSR								3
6-954 kcmil ACSR								4
6-954 kcmil ACSR								5
6-795 kcmil ACSR	187,240	23,307,161	23,494,401					6
6-795 kcmil ACSR								7
6-954 kcmil ACSR								8
6-795 kcmil ACSR	5,394,714	13,782,883	19,177,597					9
6-954 kcmil ACSR								10
6-795 kcmil ACSR								11
6-954 kcmil ACSR								12
6-795 kcmil ACSR	24,099	872,818	896,916					13
6-795 kcmil ACSR								14
6-795 kcmil ACSR	1,348,745	26,470,089	27,818,834					15
6-795 kcmil ACSR								16
6-795 kcmil ACSR								17
6-795 kcmil ACSR								18
6-954 kcmil ACSR	667,056	9,634,576	10,301,633					19
6-795 kcmil ACSR								20
6-954 kcmil ACSR								21
6-795 kcmil ACSR								22
6-954 kcmil ACSR								23
6-954 kcmil ACSR	17,816	7,665,066	7,682,882					24
6-954 kcmil ACSR								25
6-954 kcmil ACSR								26
6-795 kcmil ACSR	661,692	6,976,971	7,638,662					27
6-795 kcmil ACSR								28
6-795 kcmil ACSR								29
6-954 kcmil ACSR								30
6-795 kcmil ACSR		2,942,385	2,942,385					31
6-795 kcmil ACSR								32
6-795 kcmil ACSR								33
6-954 kcmil ACSR								34
6-795 kcmil ACSR		478,209	478,209					35
	105,408,892	1,866,079,632	1,971,488,529	1,780,386	6,929,875	2,190,831	10,901,092	36

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
6-795 kcmil ACSR								1
6-795 kcmil ACSR	353,005	3,108,909	3,461,914					2
6-795 kcmil ACSR								3
6-795 kcmil ACSR								4
6-795 kcmil ACSR								5
6-954 kcmil ACSR		196,978	196,978					6
6-954 kcmil ACSR	472,775	3,455,294	3,928,069					7
6-954 kcmil ACSR								8
6-954 kcmil ACSR								9
6-954 kcmil ACSR		1,648,291	1,648,291					10
6-795 kcmil ACSR								11
6-795 kcmil ACSR								12
6-954 kcmil ACSR								13
6-954 kcmil ACSR		564,837	564,837					14
6-954 ACSS/TW	139,860	8,455,822	8,595,682					15
6-954 ACSS/TW								16
6-954 ACSS/TW		670,200	670,200					17
6-954 kcmil ACSS								18
3-795 kcmil ACSR	437,164	8,094,209	8,531,374					19
3-795 kcmil ACSR								20
3-795 kcmil ACSR								21
3-795 kcmil ACSR								22
3-795 kcmil ACSR	29,881	1,176,747	1,206,628					23
3-795 kcmil ACSR	57,863	6,002,680	6,060,544					24
3-795 kcmil ACSR	55,625	283,964	339,589					25
3-795 kcmil ACSR	31,735	834,626	866,361					26
3-795 kcmil ACSR								27
3-954 kcmil ACSR	57,281	2,870,969	2,928,250					28
3-795 kcmil ACSR	21,223	870,044	891,267					29
3-795 kcmil ACSR								30
3-954 kcmil ACSR	24,662	1,501,217	1,525,879					31
3-795 kcmil ACSS		605,867	605,867					32
3-795 kcmil ACSR	302,577	7,615,686	7,918,263					33
3-795 kcmil ACSR								34
3-954 kcmil ACSR	1,288,507	12,625,686	13,914,193					35
	105,408,892	1,866,079,632	1,971,488,529	1,780,386	6,929,875	2,190,831	10,901,092	36

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TRANSMISSION LINE STATISTICS (Continued)			
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
3-954 kcmil ACSR	1,288,507	12,625,686	13,914,193					1
3-1272 kcmil ACSR	407,857	6,519,456	6,927,313					2
3-1272 kcmil ACSR								3
3-795 kcmil ACSS	1,023,124	23,387,110	24,410,234					4
3-795 kcmil ACSS	884,508	9,194,724	10,079,232					5
6-954 ACSS/TW	13,514	9,000,687	9,014,201					6
3-477 kcmil ACSR	143,079	1,706,835	1,849,914					7
3-477 kcmil ACSR								8
3-477 kcmil ACSR	59,271	2,015,147	2,074,419					9
3-2312 kcmil ACSR								10
3-477 kcmil ACSR								11
3-795 kcmil ACSS	52,746	1,385,384	1,438,130					12
3000 kcmil CU								13
3-795 kcmil ACSS	477,246	6,134,098	6,611,344					14
3-795 kcmil ACSS	663,115	9,558,077	10,221,191					15
3-795 kcmil ACSS								16
								17
	18,755,555	567,621,599	586,377,155					18
								19
	4,443,297	204,395,299	208,838,596					20
								21
	15,920	26,364,466	26,380,386					22
								23
				1,780,386	6,929,875	2,190,831	10,901,092	24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	105,408,892	1,866,079,632	1,971,488,529	1,780,386	6,929,875	2,190,831	10,901,092	36

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Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 422 Line No.: 7 Column: a

(0954) QUARRY-ALEXANDRIA SWITCHING STATION: Xcel Energy owns 36.1000% (27.96 miles) of 77.45 miles of this line; remaining 63.9000% (49.49 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422 Line No.: 10 Column: a

(0955) ALEXANDRIA SWITCHING STATION-BISON: Xcel Energy owns 36.1000% (48.84 miles) of 135.3 miles of this line; remaining 63.9000% (86.46 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422 Line No.: 14 Column: a

(0956) LYON COUNTY-CEDAR MOUNTAIN: Xcel Energy owns 67.8174% (33.56 miles) of 49.49 miles of this line; remaining 32.1826% (15.93 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422 Line No.: 15 Column: a

(0957) LYON COUNTY-CEDAR MOUNTAIN: Xcel Energy owns 67.8174% (33.56 miles) of 49.49 miles of this line; remaining 32.1826% (15.93 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422 Line No.: 16 Column: a

(0958) CEDAR MOUNTAIN-HELENA: Xcel Energy owns 67.8174% (49.57 miles) of 73.1 miles of this line; remaining 32.1826% (23.53 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422 Line No.: 17 Column: a

(0959) CEDAR MOUNTAIN-HELENA: Xcel Energy owns 67.8174% (49.55 miles) of 73.06 miles of this line; remaining 32.1826% (23.51 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422 Line No.: 18 Column: a

(0960) HELENA-CHUB LAKE: Xcel Energy owns 67.8174% (14.15 miles) of 20.87 miles of this line; remaining 32.1826% (06.72 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422 Line No.: 19 Column: a

(0961) CHUB LAKE-HAMPTON: Xcel Energy owns 67.8174% (12.27 miles) of 18.1 miles of this line; remaining 32.1826% (05.83 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422 Line No.: 20 Column: a

(0962) LYON COUNTY-HAZEL CREEK (LINE #1): Xcel Energy owns 67.8174% (16.41 miles) of 24.2 miles of this line; remaining 32.1826% (07.79 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422 Line No.: 21 Column: a

NSM (0965) NORTH ROCHESTER-MISSISSIPPI RIVER: Xcel Energy owns 64.0000% (27.78 miles) of 43.4 miles of this line; remaining 36.0000% (15.62 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422 Line No.: 26 Column: a

(0972) BROOKINGS COUNTY-LYON COUNTY: Xcel Energy owns 67.8174% (39.88 miles) of 58.8 miles of this line; remaining 32.1826% (18.92 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422 Line No.: 27 Column: a

(0973) MONTICELLO-QUARRY: Xcel Energy owns 36.1000% (10.39 miles) of 28.77 miles of this line; remaining 63.9000% (18.38 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.3 Line No.: 4 Column: a

(0922) BOSWELL-CASS LAKE: Xcel Energy owns 26.2000%(13.38 miles) of 51.08 miles of this line; remaining 73.8000%(37.70 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.3 Line No.: 5 Column: a

(0923) CASS LAKE-WILTON: Xcel Energy owns 26.2000%(05.06 miles) of 19.32 miles of this line; remaining 73.8000%(14.26 miles) is owned by other members of the CapX2020 joint venture

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 422.3 Line No.: 6 Column: a

NSM (0963) HAZEL CREEK-MINNESOTA VALLEY (LINE #1): Xcel Energy owns 67.8174%(03.12 miles) of 4.6 miles of this line; remaining 32.1826%(01.48 miles) is owned by other members of the CapX2020 joint venture.

Schedule Page: 422.3 Line No.: 15 Column: a

(5310) NORTH ROCHESTER-NORTHERN HILLS: Xcel Energy owns 64.0000%(09.93 miles) of 15.51 miles of this line; remaining 36.0000%(05.58 miles) is owned by other members of the CapX2020 joint venture

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.

2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	(0955) ALEXANDRIA	BISON	14.68	2 POLE	6.00	1	2
2			113.93	SINGLE POLE	6.00	1	2
3			3.99	SPECIAL 1 POLE	6.00	1	2
4			6.18	SPECIAL 2 POLE	6.00	1	2
5	(0962) LYON COUNTY	HAZEL CREEK	24.54	SINGLE POLE	6.00	1	2
6	(0965) NORTH ROCHESTER	MISSISSIPPI RIVER	32.20	SINGLE POLE	5.00	1	2
7			3.12	SPECIAL 2 POLE	5.00	1	2
8			8.03	SPECIAL 3 POLE	5.00	1	2
9	(0972) BROOKINGS	LYON COUNTY	59.30	SINGLE POLE	5.00	1	2
10	(0982) BLUE LAKE	LAKEFIELD JUNCTION	0.62	H-FRAME	10.00	1	1
11			0.58	TOWER	10.00	1	1
12	(0963) HAZEL CREEK	MINNESOTA VALLEY	4.97	SINGLE POLE	6.00	1	2
13	(5556) SCOTT COUNTY	GRE INTER. (VICTORIA)	1.40	SINGLE POLE	15.00	1	1
14			3.88	Y-FRAME	15.00	1	1
15	(5559) WEST SIOUX FALLS	FALLS	3.70	SINGLE POLE	20.00	1	1
16	(5560) GOOSE LAKE	KOHLMAN LAKE	2.61	SINGLE POLE	10.00	2	2
17	(5568) SPLIT ROCK	FALLS	7.50	SINGLE POLE	15.00	1	1
18	(0733) MINNKOTA CONN.	MINNKOTA CONN. (NEAR	0.75	SINGLE POLE	48.00	2	2
19							
20							
21							
22							
23							
24							
25							
26							
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36							
37							
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39							
40							
41							
42							
43							
44	TOTAL		291.98		199.00	20	30

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
6-954kcmil	ACSS/TW	20/7	345	7,801,660	89,040,751	17,453,499		114,295,910	1
6-954kcmil	ACSS/TW	20/7	345						2
6-954kcmil	ACSS/TW	20/7	345						3
6-954kcmil	ACSS/TW	20/7	345						4
6-954kcmil	ACSS/TW	20/7	345	73,757	18,901,493	8,100,640		27,075,890	5
6-954kcmil	ACSS/TW	20/7	345	3,747,000	56,249,167	4,985,029		64,981,196	6
6-954kcmil	ACSS/TW	20/7	345						7
6-954kcmil	ACSS/TW	20/7	345						8
6-954kcmil	ACSS/TW	20/7	345	582,207	52,897,288	23,949,112		77,428,607	9
6-795kcmil	ACSR	26/7	345	1,348,745	17,720,562	8,749,527		27,818,834	10
6-795kcmil	ACSR	26/7	345						11
6-954kcmil	ACSS/TW	20/7	230	13,514	6,300,481	2,700,206		9,014,201	12
3-795kcmil	ACSS	26/7	115		7,571,602	1,972,709		9,544,311	13
3-795kcmil	ACSS	26/7	115						14
3-959.6kcm	ACSS/TW	22/7	115		9,180,464	1,918,849		11,099,313	15
3-795kcmil	ACSS	26/7	115		4,322,769	864,201		5,186,970	16
3-959.6kcm	ACSS	22/7	115		7,868,337	964,551		8,832,888	17
3-2/0 AWG	ACSR	6/1	69	70,768	2,457,663	779,584		3,308,015	18
									19
									20
									21
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									43
				13,637,651	272,510,577	72,437,907		358,586,135	44

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 424 Line No.: 1 Column: a

NSM (0955) ALEXANDRIA SWITCHING STATION-BISON: Xcel Energy owns 36.1000% (48.84 miles) of 135.3 miles of this line; remaining 63.9000% (86.46 miles) is owned by other members of the CapX2020 joint venture.

Schedule Page: 424 Line No.: 1 Column: c

Line construction less than 0.5 miles in length are not reported as they are considered non-significant per FERC instructions; exception: if entire line is newly constructed in reporting year.

Schedule Page: 424 Line No.: 5 Column: a

NSM (0962) LYON COUNTY-HAZEL CREEK (LINE #1): Xcel Energy owns 67.8174% (16.41 miles) of 24.2 miles of this line; remaining 32.1826% (07.79 miles) is owned by other members of the CapX2020 joint venture.

Schedule Page: 424 Line No.: 6 Column: a

NSM (0965) NORTH ROCHESTER-MISSISSIPPI RIVER: Xcel Energy owns 64.0000% (27.78 miles) of 43.4 miles of this line; remaining 36.0000% (15.62 miles) is owned by other members of the CapX2020 joint venture.

Schedule Page: 424 Line No.: 9 Column: a

NSM (0972) BROOKINGS COUNTY-LYON COUNTY: Xcel Energy owns 67.8174% (39.88 miles) of 58.8 miles of this line; remaining 32.1826% (18.92 miles) is owned by other members of the CapX2020 joint venture.

Schedule Page: 424 Line No.: 12 Column: a

NSM (0963) HAZEL CREEK-MINNESOTA VALLEY (LINE #1): Xcel Energy owns 67.8174% (03.12 miles) of 4.6 miles of this line; remaining 32.1826% (01.48 miles) is owned by other members of the CapX2020 joint venture.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	A.S.KING-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
2	ADAMS-TR09	UNATTENDED TRANSM	345.00	161.00	13.80
3	ADA-TR01	UNATTENDED DISTRIB	69.00	34.50	
4	AFTON-TR01	UNATTENDED DISTRIB	115.00	34.50	
5	AFTON-TR02	UNATTENDED DISTRIB	115.00	34.50	
6	AIR LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
7	AIR LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
8	AIRPORT-TR01	UNATTENDED DISTRIB	115.00	13.80	
9	AIRPORT-TR02	UNATTENDED DISTRIB	115.00	13.80	
10	ALBANY-TR02	UNATTENDED DISTRIB	69.00	12.50	
11	ALBANY-TR03	UNATTENDED DISTRIB	12.50	12.50	
12	ALDRICH-TR02	UNATTENDED DISTRIB	115.00	13.80	
13	ALDRICH-TR03	UNATTENDED DISTRIB	115.00	13.80	
14	ALDRICH-TR04	UNATTENDED DISTRIB	115.00	13.80	
15	ALEXANDRIA-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	34.50	12.50	
16	ALTURA-TR01	UNATTENDED DISTRIB	69.00	13.80	
17	ANNANDALE-TR01	UNATTENDED DISTRIB	69.00	13.80	
18	APACHE-TR01	UNATTENDED DISTRIB	115.00	13.80	
19	APACHE-TR02	UNATTENDED DISTRIB	115.00	13.80	
20	ARDEN HILLS-TR01	UNATTENDED DISTRIB	115.00	69.00	13.80
21	ARDEN HILLS-TR02	UNATTENDED DISTRIB	115.00	69.00	13.80
22	ARLINGTON-TR01	UNATTENDED DISTRIB	69.00	12.50	
23	ARTESIAN-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	34.50	12.50	
24	ATWATER-TR01	UNATTENDED DISTRIB	69.00	13.80	
25	AVERILL-TR01	UNATTENDED DISTRIB	69.00	23.00	
26	AVON-TR01	UNATTENDED DISTRIB	69.00	12.50	
27	BASSETT CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
28	BASSETT CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
29	BATTLE CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
30	BATTLE CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
31	BAYTOWN-TR01	UNATTENDED DISTRIB	118.00	13.80	
32	BECKER-TR01	UNATTENDED DISTRIB	69.00	13.80	
33	BECKER-TR02	UNATTENDED DISTRIB	69.00	34.50	
34	BELGRADE-TR01	UNATTENDED DISTRIB	69.00	12.50	
35	BELLE PLAINE-TR01	UNATTENDED DISTRIB	69.00	13.80	
36	BIRCH-TR01	UNATTENDED DISTRIB	69.00	34.50	
37	BIRD ISLAND-TR02	UNATTENDED DISTRIB	69.00	12.50	
38	BLUE HERON-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	BLUE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	BLUE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	BLUE LAKE-TR07	UNATTENDED TRANSM	230.00	115.00	13.80
2	BLUE LAKE-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
3	BLUFF CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
4	BROOKINGS COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
5	BROOKINGS COUNTY-TR10	UNATTENDED TRANSM	345.00	115.00	13.80
6	BROOKLYN PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
7	BROOKLYN PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
8	BROOK-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	34.50	12.50	
9	BROOTEN-TR01	UNATTENDED DISTRIB	69.00	12.50	
10	BROWNTON-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	BUFFALO LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
12	BUFFALO RIDGE-TR01	UNATTENDED TRANSM	115.00	34.50	13.80
13	BUFFALO RIDGE-TR02	UNATTENDED TRANSM	115.00	34.50	13.80
14	BURNSIDE-TR01	UNATTENDED DISTRIB	69.00	13.20	
15	BURNSIDE-TR02	UNATTENDED DISTRIB	69.00	13.80	
16	BUTTERFIELD-TR01	UNATTENDED DISTRIB	69.00	12.50	
17	CANISTOTA JUNCTION-TR01	UNATTENDED DISTRIB	69.00	13.80	
18	CANISTOTA-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	69.00	12.50	
19	CANNON FALLS TRANS-TR06	UNATTENDED DISTRIB	115.00	69.00	
20	CANNON FALLS TRANS-TR07	UNATTENDED TRANSM	115.00	69.00	13.80
21	CANNON FALLS-TR01	UNATTENDED DISTRIB	69.00	12.50	
22	CANOVA-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	34.50	12.50	
23	CANTON-TR01	UNATTENDED DISTRIB	69.00	13.80	
24	CANTON-TR02	UNATTENDED DISTRIB	71.00	13.80	
25	CARVER COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	34.50
26	CARVER COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	34.50
27	CASS COUNTY-TR01X,TR01Y	UNATTENDED TRANSM	115.00	23.00	2.50
28	CASS COUNTY-TR02	UNATTENDED DISTRIB	115.00	23.00	
29	CASTLE ROCK-TR01	UNATTENDED DISTRIB	69.00	4.00	
30	CEDAR LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
31	CEDAR LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
32	CEDARVALE-TR01	UNATTENDED DISTRIB	115.00	13.80	
33	CEDARVALE-TR02	UNATTENDED DISTRIB	115.00	13.80	
34	CENTERVILLE-TR01	UNATTENDED DISTRIB	69.00	4.00	
35	CHANARAMBIE-TR01	UNATTENDED TRANSM	115.00	34.50	13.80
36	CHANARAMBIE-TR02	UNATTENDED TRANSM	115.00	34.50	13.80
37	CHANARAMBIE-TR04	UNATTENDED TRANSM	115.00	34.50	13.80
38	CHEMOLITE-TR01	UNATTENDED DISTRIB	115.00	12.50	
39	CHEMOLITE-TR02	UNATTENDED DISTRIB	115.00	12.50	
40	CHERRY CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	CHERRY CREEK-TR03	UNATTENDED DISTRIB	115.00	34.50	
2	CHISAGO COUNTY-TR02	UNATTENDED DISTRIB	115.00	34.50	
3	CHISAGO COUNTY-TR06	UNATTENDED TRANSM	345.00	161.00	34.50
4	CHISAGO COUNTY-TR09A,TR09B,TR09C	UNATTENDED TRANSM	500.00	345.00	34.50
5	CHISAGO COUNTY-TR10SA,TR10B,TR10C	UNATTENDED TRANSM	500.00	345.00	34.50
6	CLARA CITY-TR01	UNATTENDED DISTRIB	69.00	12.50	
7	CLARA CITY-TR02	UNATTENDED DISTRIB	88.00	23.00	
8	CLARKS GROVE-TR01	UNATTENDED DISTRIB	69.00	12.50	
9	CLIFF AVENUE-TR01	UNATTENDED DISTRIB	69.00	12.50	
10	CLIFF AVENUE-TR02	UNATTENDED DISTRIB	69.00	13.80	
11	COKATO-TR01	UNATTENDED DISTRIB	69.00	13.80	
12	COLVILL-TR04	UNATTENDED TRANSM	115.00	69.00	13.80
13	COLVILL-TR05	UNATTENDED TRANSM	161.00	115.00	13.80
14	COON CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
15	COON CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
16	COON CREEK-TR09	UNATTENDED TRANSM	345.00	115.00	34.50
17	COON CREEK-TR10	UNATTENDED TRANSM	345.00	115.00	34.50
18	COTTAGE GROVE-TR01	UNATTENDED DISTRIB	115.00	13.80	
19	COTTAGE GROVE-TR02	UNATTENDED DISTRIB	115.00	13.80	
20	CREDIT RIVER-TR01	UNATTENDED DISTRIB	69.00	12.50	
21	CREDIT RIVER-TR02	UNATTENDED DISTRIB	69.00	12.50	
22	CROOKED LAKE-TR01	UNATTENDED DISTRIB	119.00	13.80	
23	CROOKED LAKE-TR02	UNATTENDED DISTRIB	119.00	13.80	
24	CROOKED LAKE-TR03	13	115.00	12.50	
25	CROOKED LAKE-TR65A,TR65B,TR65C	UNATTENDED DISTRIB	13.80	12.50	
26	CROSSROADS-TR01	UNATTENDED DISTRIB	115.00	13.80	
27	CROSSROADS-TR02	UNATTENDED DISTRIB	115.00	13.80	
28	CROSSROADS-TR03	UNATTENDED DISTRIB	115.00	13.80	
29	CRYSTAL FOODS-TR01	UNATTENDED DISTRIB	69.00	13.80	
30	DAHLGREN-TR01	UNATTENDED DISTRIB	115.00	13.80	
31	DANUBE-TR01	UNATTENDED DISTRIB	69.00	12.50	
32	DASSEL-TR01	UNATTENDED DISTRIB	69.00	13.80	
33	DAYTONS BLUFF-TR01	UNATTENDED DISTRIB	115.00	13.80	
34	DAYTONS BLUFF-TR02	UNATTENDED DISTRIB	115.00	13.80	
35	DAYTONS BLUFF-TR03	UNATTENDED DISTRIB	115.00	13.80	
36	DEEPHAVEN-TR01	UNATTENDED DISTRIB	69.00	13.80	
37	DEEPHAVEN-TR02	UNATTENDED DISTRIB	69.00	13.80	
38	DELANO-TR01X,TR01Y	UNATTENDED DISTRIB	69.00	7.20	
39	DELL RAPIDS-TR02	UNATTENDED DISTRIB	34.50	12.50	
40	DODGE CENTER-TR01	UNATTENDED DISTRIB	69.00	34.50	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	DODGE CENTER-TR02	UNATTENDED DISTRIB	69.00	12.50	
2	DODGE CENTER-TR03	UNATTENDED DISTRIB	69.00	13.80	
3	DOME PIPELINE-TR01	UNATTENDED DISTRIB	115.00	4.16	
4	DOUGLAS COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	34.50
5	DOUGLAS COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	34.50
6	DOUGLAS COUNTY-TR03	UNATTENDED DISTRIB	69.00	13.80	
7	DUNDAS-TR01	UNATTENDED DISTRIB	69.00	13.80	
8	DUNDAS-TR02	UNATTENDED DISTRIB	69.00	13.80	
9	EAGLE LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
10	EAST BLOOMINGTON-TR01	UNATTENDED DISTRIB	115.00	13.80	
11	EAST BLOOMINGTON-TR02	UNATTENDED DISTRIB	115.00	13.80	
12	EAST BLOOMINGTON-TR03	UNATTENDED DISTRIB	115.00	13.80	
13	EAST WINONA-TR01	UNATTENDED DISTRIB	69.00	12.50	
14	EASTWOOD-TR01	UNATTENDED DISTRIB	69.00	13.80	
15	EASTWOOD-TR02	UNATTENDED DISTRIB	69.00	13.80	
16	ECHO-TR01	UNATTENDED DISTRIB	23.00	12.50	
17	EDEN PRAIRIE-TR01	UNATTENDED DISTRIB	115.00	13.80	
18	EDEN PRAIRIE-TR03	UNATTENDED DISTRIB	115.00	13.80	
19	EDEN PRAIRIE-TR04	UNATTENDED DISTRIB	115.00	13.80	
20	EDEN PRAIRIE-TR09	UNATTENDED TRANSM	345.00	161.00	13.80
21	EDEN PRAIRIE-TR10	UNATTENDED TRANSM	345.00	161.00	13.80
22	EDGERTON-TR01	UNATTENDED DISTRIB	23.00	12.50	
23	EDINA-TR01	UNATTENDED DISTRIB	115.00	13.80	
24	EDINA-TR02	UNATTENDED DISTRIB	115.00	13.80	
25	EDINA-TR03	UNATTENDED DISTRIB	115.00	13.80	
26	ELLIOT PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
27	ELLIOT PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
28	ELLIOT PARK-TR03	UNATTENDED DISTRIB	115.00	13.80	
29	ELM CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
30	ELM CREEK-TR02	UNATTENDED DISTRIB	115.00	34.50	
31	ELM CREEK-TR03	UNATTENDED DISTRIB	115.00	13.80	
32	ELM CREEK-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
33	EMERY-TR01A,TR01B,TR01CC	UNATTENDED DISTRIB	34.50	2.40	
34	EMPIRE PARK-TR01	UNATTENDED DISTRIB	34.50	12.50	
35	EMPIRE PARK-TR02	UNATTENDED DISTRIB	34.50	12.50	
36	ESSIG-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	69.00	2.50	
37	EXCELSIOR-TR01	UNATTENDED DISTRIB	69.00	13.80	
38	FAIR PARK-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	FAIR PARK-TR02	UNATTENDED DISTRIB	69.00	13.80	
40	FARIBAULT-TR01	UNATTENDED DISTRIB	69.00	13.80	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

- Report below the information called for concerning substations of the respondent as of the end of the year.
- Substations which serve only one industrial or street railway customer should not be listed below.
- Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
- Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	FARIBAULT-TR02	UNATTENDED DISTRIB	69.00	13.80	
2	FARMINGTON-TR01	UNATTENDED DISTRIB	69.00	13.80	
3	FARMINGTON-TR02	UNATTENDED DISTRIB	69.00	13.80	
4	FENTON-TR01	UNATTENDED TRANSM	115.00	34.50	13.80
5	FENTON-TR02	UNATTENDED TRANSM	115.00	34.50	13.80
6	FENTON-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
7	FIESTA CITY-TR01	UNATTENDED DISTRIB	69.00	12.50	
8	FIFTH STREET-TR01	UNATTENDED DISTRIB	115.00	13.80	
9	FIFTH STREET-TR02	UNATTENDED DISTRIB	115.00	13.80	
10	FIFTH STREET-TR03	UNATTENDED DISTRIB	115.00	13.80	
11	FIFTH STREET-TR04	UNATTENDED DISTRIB	115.00	13.80	
12	FOLEY-TR01	UNATTENDED DISTRIB	34.50	12.50	
13	FORBES-TR09	UNATTENDED TRANSM	500.00	20.00	
14	FORT RIDGLEY-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
15	FRANKLIN-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
16	FRANKLIN-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
17	FRANKLIN-TR04	UNATTENDED DISTRIB	69.00	23.00	
18	FRANKLIN-TR07	UNATTENDED DISTRIB	69.00	23.00	
19	FRONTENAC-TR01	UNATTENDED DISTRIB	69.00	13.80	
20	GATEWAY-TR01	UNATTENDED DISTRIB	69.00	12.50	
21	GATEWAY-TR02	UNATTENDED DISTRIB	69.00	12.50	
22	GAYLORD-TR01	UNATTENDED DISTRIB	69.00	4.00	
23	GIBBON-TR01	UNATTENDED DISTRIB	69.00	12.50	
24	GLEASON LAKE-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
25	GLEASON LAKE-TR03	UNATTENDED DISTRIB	34.50	13.80	
26	GLEASON LAKE-TR04	UNATTENDED DISTRIB	115.00	34.50	
27	GLEASON LAKE-TR07	UNATTENDED DISTRIB	115.00	13.80	
28	GLEASON LAKE-TR08	UNATTENDED DISTRIB	115.00	13.80	
29	GLEN LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
30	GLEN LAKE-TR02	UNATTENDED DISTRIB	69.00	13.80	
31	GLENWOOD-TR01	UNATTENDED DISTRIB	69.00	13.80	
32	GLENWOOD-TR02	UNATTENDED DISTRIB	69.00	12.50	
33	GOODVIEW-TR01	UNATTENDED DISTRIB	69.00	12.50	
34	GOODVIEW-TR02	UNATTENDED DISTRIB	69.00	12.50	
35	GOOSE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
36	GOOSE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
37	GOPHER-TR01	UNATTENDED DISTRIB	115.00	13.80	
38	GOPHER-TR02	UNATTENDED DISTRIB	115.00	13.80	
39	GRANITE CITY-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	GRANITE CITY-TR02	UNATTENDED DISTRIB	115.00	13.80	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	GRANITE CITY-TR03	UNATTENDED DISTRIB	115.00	34.50	
2	GRANT-TR01	UNATTENDED TRANSM	115.00	69.00	2.40
3	GRANT-TR03	UNATTENDED DISTRIB	115.00	34.50	
4	GREEN ISLE-TR01	UNATTENDED DISTRIB	69.00	12.50	
5	GREENFIELD-TR01	UNATTENDED DISTRIB	69.00	12.50	
6	HADLEY-TR01	UNATTENDED DISTRIB	69.00	13.80	
7	HASSAN-TR01	UNATTENDED DISTRIB	115.00	34.50	
8	HASSAN-TR02	UNATTENDED DISTRIB	115.00	34.50	
9	HASTINGS-TR01	UNATTENDED DISTRIB	69.00	13.80	
10	HASTINGS-TR02	UNATTENDED DISTRIB	69.00	13.80	
11	HATFIELD-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	13.80	6.90	
12	HATTON-TR01	UNATTENDED DISTRIB	69.00	12.50	
13	HAZEL CREEK-TR09	UNATTENDED TRANSM	345.00	230.00	13.80
14	HECTOR-TR01	UNATTENDED DISTRIB	69.00	12.50	
15	HENDERSON-TR01	UNATTENDED DISTRIB	69.00	12.50	
16	HIAWATHA WEST-TR01	UNATTENDED DISTRIB	115.00	13.80	
17	HIGH BRIDGE-TR04	UNATTENDED DISTRIB	115.00	13.80	
18	HOLLYDALE-TR01	UNATTENDED DISTRIB	69.00	13.80	
19	HOLLYDALE-TR02	UNATTENDED DISTRIB	34.50	13.80	
20	HOWARD JUNCTION-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	34.50	12.50	
21	HOWARD LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
22	HUGO-TR01	UNATTENDED DISTRIB	115.00	34.50	
23	HUGO-TR02	UNATTENDED DISTRIB	115.00	34.50	
24	HYLAND LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
25	HYLAND LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
26	INDIANA-TR01	UNATTENDED DISTRIB	115.00	13.80	
27	INDIANA-TR02	UNATTENDED DISTRIB	115.00	13.80	
28	INDUSTRIAL-TR01	UNATTENDED DISTRIB	34.50	12.50	
29	INDUSTRIAL-TR02	UNATTENDED DISTRIB	34.50	12.50	
30	INVER GROVE-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
31	INVER GROVE-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
32	INVER HILLS-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
33	JORDAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
34	KASSON-TR01	UNATTENDED DISTRIB	69.00	12.50	
35	KASSON-TR02	UNATTENDED DISTRIB	69.00	12.50	
36	KEGAN LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
37	KENYON-TR01	UNATTENDED DISTRIB	69.00	12.50	
38	KIMBALL-TR01	UNATTENDED DISTRIB	69.00	12.50	
39	KOCH REFINERY-TR11	UNATTENDED DISTRIB	115.00	13.80	
40	KOCH REFINERY-TR12	UNATTENDED DISTRIB	115.00	13.80	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	KOCH REFINERY-TR13	UNATTENDED DISTRIB	115.00	13.80	
2	KOCH REFINERY-TR14	UNATTENDED DISTRIB	115.00	13.80	
3	KOCH REFINERY-TR15	UNATTENDED DISTRIB	118.00	13.80	
4	KOCH REFINERY-TR16	UNATTENDED DISTRIB	115.00	13.80	
5	KOHLMAN LAKE-TR01	UNATTENDED DISTRIB	115.00	34.50	
6	KOHLMAN LAKE-TR02	UNATTENDED DISTRIB	115.00	69.00	34.50
7	KOHLMAN LAKE-TR09	UNATTENDED TRANSM	115.00	69.00	13.80
8	KOHLMAN LAKE-TR10	UNATTENDED TRANSM	345.00	115.00	13.80
9	LA CRESENT-TR01	UNATTENDED DISTRIB	69.00	13.80	
10	LAFAYETTE-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	LAKE CITY-TR01	UNATTENDED DISTRIB	68.80	13.80	
12	LAKE CITY-TR02	UNATTENDED DISTRIB	68.80	13.80	
13	LAKE EMILY-TR01	UNATTENDED DISTRIB	69.00	13.80	
14	LAKE LILAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
15	LAKE PULASKI-TR03	UNATTENDED DISTRIB	115.00	34.50	
16	LAKE PULASKI-TR05	UNATTENDED TRANSM	115.00	69.00	34.50
17	LAKE PULASKI-TR06	UNATTENDED TRANSM	115.00	69.00	13.80
18	LAKE YANKTON-TR01	UNATTENDED TRANSM	115.00	69.00	2.50
19	LAKE YANKTON-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
20	LAKE YANKTON-TR03	UNATTENDED DISTRIB	69.00	13.80	
21	LARIMORE-TR01	UNATTENDED DISTRIB	69.00	12.50	
22	LAWRENCE CREEK-TR01	UNATTENDED DISTRIB	115.00	34.50	
23	LAWRENCE CREEK-TR04	UNATTENDED TRANSM	115.00	69.00	13.80
24	LAWRENCE CREEK-TR05	UNATTENDED TRANSM	161.00	115.00	13.80
25	LAWRENCE-TR01	UNATTENDED DISTRIB	115.00	34.50	
26	LAWRENCE-TR07	UNATTENDED TRANSM	115.00	69.00	13.80
27	LAWRENCE-TR08	UNATTENDED TRANSM	118.00	69.00	
28	LENNOX-TR01	UNATTENDED DISTRIB	69.00	13.80	
29	LESTER PRAIRIE-TR01	UNATTENDED DISTRIB	69.00	23.00	
30	LEXINGTON-TR01	UNATTENDED DISTRIB	115.00	13.80	
31	LEXINGTON-TR02	UNATTENDED DISTRIB	115.00	12.50	
32	LEXINGTON-TR03	UNATTENDED DISTRIB	115.00	34.50	
33	LEXINGTON-TR04	UNATTENDED DISTRIB	34.50	13.80	
34	LINCOLN CO-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
35	LINCOLN CO-TR07	UNATTENDED DISTRIB	115.00	13.80	
36	LINCOLN CO-TR08	UNATTENDED DISTRIB	115.00	12.50	
37	LINDE-TR01	UNATTENDED DISTRIB	115.00	13.80	
38	LINDSTROM-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	LINDSTROM-TR02	UNATTENDED DISTRIB	69.00	12.50	
40	LINN STREET-TR01	UNATTENDED DISTRIB	69.00	12.50	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	LINN STREET-TR02	UNATTENDED DISTRIB	69.00	12.50	
2	LONE OAK-TR01	UNATTENDED DISTRIB	115.00	13.80	
3	LONE OAK-TR02	UNATTENDED DISTRIB	115.00	13.80	
4	LONG LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
5	LONG LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
6	LOON LAKE-TR06	UNATTENDED TRANSM	115.00	69.00	13.80
7	LOUISE-TR01	UNATTENDED DISTRIB	115.00	13.80	
8	LOWRY-TR01	UNATTENDED DISTRIB	115.00	13.80	
9	LYON COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
10	LYON COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	34.50
11	M E INTERNATIONAL-TR01	UNATTENDED DISTRIB	115.00	13.80	
12	M E INTERNATIONAL-TR02	UNATTENDED DISTRIB	115.00	13.80	
13	M E INTERNATIONAL-TRBT	UNATTENDED DISTRIB	15.00	13.80	
14	MAIN STREET-TR01	UNATTENDED DISTRIB	115.00	13.80	
15	MAIN STREET-TR02	UNATTENDED DISTRIB	115.00	13.80	
16	MAPLE LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
17	MAPLE RIVER-TR05	UNATTENDED TRANSM	230.00	161.00	13.80
18	MAPLE RIVER-TR06	UNATTENDED TRANSM	230.00	115.00	13.80
19	MAPLETON-TR01	UNATTENDED DISTRIB	69.00	13.80	
20	MARION-TR01	UNATTENDED DISTRIB	23.00	12.50	
21	MARSHALL-TR01	UNATTENDED DISTRIB	13.20	12.50	
22	MAXWELL-TR01	UNATTENDED DISTRIB	115.00	4.13	
23	MAYHEW LAKE-TR01	UNATTENDED DISTRIB	115.00	34.50	
24	MAYNARD (TRANSMISSION STATION)-TR01	UNATTENDED DISTRIB	115.00	69.00	
25	MAYNARD-TR01	UNATTENDED DISTRIB	69.00	12.50	
26	MAYVILLE-TR01	UNATTENDED DISTRIB	69.00	12.50	
27	MAYVILLE-TR02	UNATTENDED DISTRIB	69.00	12.50	
28	MAZEPPA-TR01	UNATTENDED DISTRIB	69.00	12.50	
29	MEDFORD JCT-TR01	UNATTENDED DISTRIB	69.00	12.50	
30	MEDICINE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
31	MEDICINE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
32	MEDICINE LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
33	MEIRE GROVE-TR01	UNATTENDED DISTRIB	69.00	12.50	
34	MERIDAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
35	MERRIAM PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
36	MERRIAM PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
37	MERRIAM PARK-TR03	UNATTENDED DISTRIB	115.00	13.80	
38	MIDTOWN	UNATTENDED DISTRIB	115.00	13.80	
39	MINNEHAHA-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	MINNEHAHA-TR02	UNATTENDED DISTRIB	115.00	13.80	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	MINNESOTA LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
2	MINNESOTA PIPELINE-TR01	UNATTENDED DISTRIB	115.00	4.16	
3	MINNESOTA VALLEY-TR02	UNATTENDED DISTRIB	69.00	34.50	
4	MINNESOTA VALLEY-TR05	UNATTENDED TRANSM	230.00	115.00	13.80
5	MINNESOTA VALLEY-TR06	UNATTENDED TRANSM	230.00	115.00	13.80
6	MINNESOTA VALLEY-TR11	UNATTENDED TRANSM	115.00	69.00	13.80
7	MINNESOTA VALLEY-TR12	UNATTENDED TRANSM	115.00	69.00	13.80
8	MONTEVIDEO-TR01	UNATTENDED DISTRIB	69.00	12.50	
9	MONTEVIDEO-TR02	UNATTENDED DISTRIB	69.00	12.50	
10	MONTICELLO-TR06	UNATTENDED TRANSM	345.00	230.00	13.80
11	MONTICELLO-TR10	UNATTENDED TRANSM	345.00	161.00	13.80
12	MONTROSE-TR01	UNATTENDED DISTRIB	69.00	12.50	
13	MOORE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
14	MOORE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
15	MOORE LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
16	MORGAN-TR01	UNATTENDED DISTRIB	69.00	34.50	
17	MORRELL-TR01	UNATTENDED DISTRIB	69.00	12.50	
18	MORRISTOWN-TR01	UNATTENDED DISTRIB	69.00	12.50	
19	MOUND-TR01	UNATTENDED DISTRIB	69.00	13.80	
20	MOUND-TR02	UNATTENDED DISTRIB	69.00	13.80	
21	NERSTRAND-TR01X,TR01Y	UNATTENDED DISTRIB	69.00	12.50	
22	NINE MILE CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
23	NINE MILE CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
24	NOBLES COUNTY-TR01	UNATTENDED TRANSM	115.00	34.50	13.80
25	NOBLES COUNTY-TR02	UNATTENDED TRANSM	115.00	34.50	13.80
26	NOBLES COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	34.50
27	NOBLES COUNTY-TR10	UNATTENDED TRANSM	345.00	115.00	34.50
28	NORDIC-TR01	UNATTENDED DISTRIB	115.00	13.80	
29	NORDIC-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	NORTH BROADWAY-TR01	UNATTENDED DISTRIB	23.00	12.50	
31	NORTH BROADWAY-TR02	UNATTENDED DISTRIB	23.00	12.50	
32	NORTH ROCHESTER-TR09	UNATTENDED TRANSM	345.00	161.00	34.50
33	NORTH STAR STEEL-TR01	UNATTENDED DISTRIB	115.00	13.80	
34	NORTH STAR STEEL-TR02	UNATTENDED DISTRIB	115.00	13.80	
35	NORTH STAR STEEL-TR03	UNATTENDED DISTRIB	115.00	13.80	
36	NORTHFIELD-TR01	UNATTENDED DISTRIB	69.00	13.80	
37	NORTHFIELD-TR02	UNATTENDED DISTRIB	69.00	13.80	
38	OAK PARK-TR01	UNATTENDED TRANSM	115.00	23.00	13.80
39	OAK PARK-TR07	UNATTENDED DISTRIB	115.00	13.80	
40	OAK PARK-TR08	UNATTENDED DISTRIB	115.00	13.80	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	OAKDALE-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	OAKDALE-TR02	UNATTENDED DISTRIB	115.00	13.80	
3	ORONO-TR01	UNATTENDED DISTRIB	69.00	13.80	
4	OSAKIS-TR01	UNATTENDED DISTRIB	69.00	12.50	
5	OSSEO-TR01	UNATTENDED DISTRIB	115.00	13.80	
6	OSSEO-TR02	UNATTENDED DISTRIB	115.00	13.80	
7	PARKERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
8	PARKERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
9	PARKERS LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
10	PARKERS LAKE-TR09A,TR09B,TR09C	UNATTENDED TRANSM	345.00	115.00	13.80
11	PARKERS LAKE-TR10A,TR10B,TR10C	UNATTENDED TRANSM	345.00	115.00	13.80
12	PARK-TR01	UNATTENDED DISTRIB	69.00	12.50	
13	PAYNESVILLE TRANSM SUB-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
14	PAYNESVILLE TRANSM SUB-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
15	PAYNESVILLE TRANSM SUB-TR04	UNATTENDED DISTRIB	115.00	34.50	
16	PAYNESVILLE TRANSM SUB-TR09	UNATTENDED TRANSM	230.00	115.00	13.80
17	PAYNESVILLE-TR01	UNATTENDED DISTRIB	34.50	12.50	
18	PINE BEND-TR01	UNATTENDED DISTRIB	69.00	12.50	
19	PINE BEND-TR02	UNATTENDED DISTRIB	69.00	12.50	
20	PINE BEND-TR03	UNATTENDED DISTRIB	69.00	13.80	
21	PINE ISLAND-TR01	UNATTENDED DISTRIB	69.00	12.50	
22	PINE ISLAND-TR02	UNATTENDED DISTRIB	69.00	12.50	
23	PIPESTONE-TR01	UNATTENDED DISTRIB	69.00	12.50	
24	PIPESTONE-TR02	UNATTENDED DISTRIB	69.00	12.50	
25	PIPESTONE-TR03	UNATTENDED DISTRIB	69.00	34.50	
26	PIPESTONE-TR05	UNATTENDED TRANSM	115.00	69.00	2.50
27	PIPESTONE-TR06	UNATTENDED TRANSM	115.00	69.00	13.80
28	PLATO-TR01	UNATTENDED DISTRIB	69.00	12.50	
29	PRAIRIE ISLAND-TR10	UNATTENDED TRANSM	345.00	161.00	13.80
30	PRAIRIE-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
31	PRAIRIE-TR03	UNATTENDED TRANSM	115.00	69.00	13.80
32	PRAIRIE-TR05	UNATTENDED TRANSM	230.00	115.00	13.80
33	PRAIRIE-TR06	UNATTENDED TRANSM	230.00	115.00	13.80
34	PRIOR-TR01	UNATTENDED DISTRIB	115.00	13.80	
35	QUARRY-TR09	UNATTENDED TRANSM	345.00	115.00	34.50
36	RAMSEY-TR01	UNATTENDED DISTRIB	115.00	13.80	
37	RAMSEY-TR02	UNATTENDED DISTRIB	115.00	13.80	
38	RAPIDAN-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	RED RIVER-TR01	UNATTENDED TRANSM	115.00	23.00	13.80
40	RED RIVER-TR02	UNATTENDED DISTRIB	115.00	23.00	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	RED RIVER-TR03	UNATTENDED TRANSM	115.00	23.00	4.80
2	RED ROCK-TR01	UNATTENDED DISTRIB	115.00	13.80	
3	RED ROCK-TR02	UNATTENDED DISTRIB	115.00	13.80	
4	RED ROCK-TR03	UNATTENDED DISTRIB	115.00	13.80	
5	RED ROCK-TR05	UNATTENDED TRANSM	345.00	230.00	13.80
6	RED ROCK-TR09	UNATTENDED TRANSM	345.00	161.00	13.80
7	RED ROCK-TR10	UNATTENDED TRANSM	345.00	161.00	13.80
8	RED WING-TR01	UNATTENDED DISTRIB	69.00	13.80	
9	RED WING-TR02	UNATTENDED DISTRIB	69.00	13.80	
10	RENVILLE-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	REYNOLDS-TR01	UNATTENDED DISTRIB	69.00	12.50	
12	RICH SPRING-TR01	UNATTENDED DISTRIB	69.00	13.80	
13	RICH VALLEY-TR01	UNATTENDED DISTRIB	115.00	13.80	
14	RICHMOND-TR01	UNATTENDED DISTRIB	69.00	34.50	
15	RIVERSIDE-TR01	UNATTENDED DISTRIB	115.00	13.80	
16	RIVERSIDE-TR02	UNATTENDED DISTRIB	115.00	13.80	
17	RIVERWOOD-TR01	UNATTENDED DISTRIB	115.00	13.80	
18	RIVERWOOD-TR02	UNATTENDED DISTRIB	115.00	13.80	
19	ROCK RIVER-TR01	UNATTENDED DISTRIB	69.00	23.00	
20	ROGERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
21	ROGERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
22	ROSE PLACE-TR01	UNATTENDED DISTRIB	115.00	13.80	
23	ROSE PLACE-TR02	UNATTENDED DISTRIB	115.00	13.80	
24	ROSEMOUNT-TR01	UNATTENDED DISTRIB	115.00	34.50	
25	RUTHTON-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	14.30	7.50	
26	SACRED HEART-TR01	UNATTENDED TRANSM	69.00	13.80	4.36
27	SALEM-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	69.00	34.50	
28	SALEM-TR02	UNATTENDED DISTRIB	69.00	12.50	
29	SALIDA CROSSING-TR01	UNATTENDED DISTRIB	115.00	23.00	
30	SARTELL-TR01	UNATTENDED DISTRIB	34.50	12.50	
31	SAUK RIVER-TR01	UNATTENDED DISTRIB	115.00	34.50	
32	SAVAGE-TR01	UNATTENDED DISTRIB	115.00	13.80	
33	SAVAGE-TR02	UNATTENDED DISTRIB	115.00	13.80	
34	SCANDIA-TR01	UNATTENDED DISTRIB	69.00	34.50	
35	SCOTT COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
36	SCOTT COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
37	SEDAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
38	SHAKOPEE-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	SHAKOPEE-TR02	UNATTENDED DISTRIB	69.00	13.80	
40	SHEAS LAKE-TR05	UNATTENDED TRANSM	115.00	69.00	13.80

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	SHEAS LAKE-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
2	SHEPARD-TR01	UNATTENDED DISTRIB	115.00	13.80	
3	SHEPARD-TR02	UNATTENDED DISTRIB	115.00	13.80	
4	SHERCO-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
5	SHEYENNE-TR05	UNATTENDED TRANSM	230.00	161.00	13.80
6	SHEYENNE-TR06	UNATTENDED TRANSM	230.00	115.00	13.80
7	SIBLEY PARK-TR01	UNATTENDED DISTRIB	69.00	13.80	
8	SIBLEY PARK-TR02	UNATTENDED DISTRIB	69.00	13.80	
9	SIOUX FALLS-TR07	UNATTENDED DISTRIB	69.00	13.80	
10	SIOUX FALLS-TR08	UNATTENDED DISTRIB	69.00	13.80	
11	SLAYTON WEST-TR01	UNATTENDED DISTRIB	69.00	13.80	
12	SOURIS-TR01	UNATTENDED DISTRIB	115.00	13.80	
13	SOURIS-TR02	UNATTENDED DISTRIB	115.00	13.80	
14	SOURIS-TR03	UNATTENDED DISTRIB	115.00	13.80	
15	SOUTH BEND-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
16	SOUTH BEND-TR06	UNATTENDED TRANSM	161.00	115.00	13.80
17	SOUTH HAVEN-TR01	UNATTENDED DISTRIB	69.00	34.50	
18	SOUTH RIDGE-TR01	UNATTENDED DISTRIB	69.00	34.50	
19	SOUTH SIOUX FALLS-TR01	UNATTENDED DISTRIB	69.00	12.50	
20	SOUTH SIOUX FALLS-TR02	UNATTENDED DISTRIB	69.00	12.50	
21	SOUTH SIOUX FALLS-TR03	UNATTENDED DISTRIB	69.00	13.80	
22	SOUTH SIOUX FALLS-TR04	UNATTENDED DISTRIB	69.00	13.80	
23	SOUTHTOWN-TR01	UNATTENDED DISTRIB	115.00	13.80	
24	SOUTHTOWN-TR02	UNATTENDED DISTRIB	115.00	13.80	
25	SOUTHTOWN-TR03	UNATTENDED DISTRIB	115.00	13.80	
26	SOUTH-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	69.00	2.40	
27	SPLIT ROCK-TR06	UNATTENDED TRANSM	161.00	115.00	34.50
28	SPLIT ROCK-TR07	UNATTENDED TRANSM	230.00	161.00	13.80
29	SPLIT ROCK-TR10	UNATTENDED TRANSM	345.00	161.00	13.80
30	SPLIT ROCK-TR11	UNATTENDED TRANSM	345.00	161.00	13.80
31	ST JAMES-TR01	UNATTENDED DISTRIB	69.00	12.50	
32	ST JOHNS-TR01	UNATTENDED DISTRIB	69.00	12.50	
33	ST. CLAIRE-TR01	UNATTENDED DISTRIB	13.20	12.50	
34	ST. CLAIRE-TR02	UNATTENDED DISTRIB	13.20	12.50	
35	ST. CLOUD-TR01	UNATTENDED DISTRIB	115.00	34.50	
36	ST. CLOUD-TR02	UNATTENDED DISTRIB	115.00	34.50	
37	ST. JOSEPH-TR01	UNATTENDED DISTRIB	69.00	12.50	
38	ST. LOUIS PARK-TR02	UNATTENDED DISTRIB	115.00	34.50	
39	ST. LOUIS PARK-TR04	UNATTENDED DISTRIB	115.00	13.80	
40	ST. LOUIS PARK-TR05	UNATTENDED DISTRIB	115.00	13.80	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

- Report below the information called for concerning substations of the respondent as of the end of the year.
- Substations which serve only one industrial or street railway customer should not be listed below.
- Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
- Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	ST. LOUIS PARK-TR06	UNATTENDED DISTRIB	115.00	13.80	
2	ST. PAUL WATER DEPT-TR01	UNATTENDED DISTRIB	23.00	12.50	
3	STEWART-TR01	UNATTENDED DISTRIB	69.00	12.50	
4	STOCKYARDS-TR01	UNATTENDED DISTRIB	115.00	13.80	
5	STOCKYARDS-TR02	UNATTENDED DISTRIB	118.00	13.80	
6	SUMMIT AVENUE-TR01	UNATTENDED DISTRIB	115.00	23.00	
7	SUMMIT AVENUE-TR02	UNATTENDED DISTRIB	115.00	13.80	
8	SWAN LAKE-TR01	UNATTENDED DISTRIB	115.00	12.50	
9	TANNERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
10	TANNERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
11	TANNERS LAKE-TR23A1,TR23B1,TR23C1	UNATTENDED DISTRIB	13.80	12.50	
12	TANNERS LAKE-TR23A2,TR23B2,TR23C2	UNATTENDED DISTRIB	13.80	12.50	
13	TANNERS LAKE-TR32A1,TR32B1,TR32C1	UNATTENDED DISTRIB	13.80	12.50	
14	TANNERS LAKE-TR32A2,TR32B2,TR32C2	UNATTENDED DISTRIB	13.80	12.50	
15	TANNERS LAKE-TR34A1,TR34B1,TR34C1	UNATTENDED DISTRIB	13.80	12.50	
16	TANNERS LAKE-TR34A2,TR34B2,TR34C2	UNATTENDED DISTRIB	13.80	12.50	
17	TERMINAL-TR01	UNATTENDED DISTRIB	115.00	13.80	
18	TERMINAL-TR02	UNATTENDED DISTRIB	115.00	13.80	
19	TERMINAL-TR03	UNATTENDED DISTRIB	115.00	13.80	
20	TERMINAL-TR09	UNATTENDED TRANSM	345.00	115.00	34.50
21	TERMINAL-TR10	UNATTENDED TRANSM	345.00	115.00	34.50
22	THOMPSON-TR01	UNATTENDED DISTRIB	69.00	12.50	
23	TRACY SW STA-TR01	UNATTENDED DISTRIB	69.00	13.80	
24	TRACY-TR01	UNATTENDED DISTRIB	69.00	12.50	
25	TWIN LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
26	TWIN LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
27	TWIN LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
28	UPPER LEVEE-TR01	UNATTENDED DISTRIB	115.00	23.00	
29	UPPER LEVEE-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	UPPER LEVEE-TR03	UNATTENDED DISTRIB	115.00	13.80	
31	VERMILLION RIVER-TR03	UNATTENDED DISTRIB	115.00	13.80	
32	VERMILLION-TR01	UNATTENDED DISTRIB	23.00	12.50	
33	VESELI-TR01	UNATTENDED DISTRIB	69.00	13.80	
34	VILLARD-TR01	UNATTENDED DISTRIB	69.00	12.50	
35	WABASHA-TR01	UNATTENDED DISTRIB	69.00	13.80	
36	WABASHA-TR02	UNATTENDED DISTRIB	69.00	2.40	
37	WACONIA-TR01	UNATTENDED DISTRIB	69.00	13.80	
38	WAKEFIELD-TR02	UNATTENDED DISTRIB	115.00	34.50	2.00
39	WAKEFIELD-TR02A,TR02B,TR02C	UNATTENDED DISTRIB	34.50	13.80	
40	WAKEFIELD-TR06	UNATTENDED TRANSM	115.00	69.00	13.80

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	WALDORF-TR01	UNATTENDED DISTRIB	23.00	12.50	
2	WASECA-TR03	UNATTENDED DISTRIB	69.00	23.00	
3	WASECA-TR02	UNATTENDED DISTRIB	69.00	23.00	
4	WASECA-TR04	UNATTENDED DISTRIB	69.00	34.50	
5	WATAB RIVER-TR01	UNATTENDED DISTRIB	69.00	12.50	
6	WATERTOWN-TR01	UNATTENDED DISTRIB	69.00	13.80	
7	WATERVILLE-TR01	UNATTENDED DISTRIB	69.00	34.50	
8	WATERVILLE-TR02	UNATTENDED DISTRIB	69.00	12.50	
9	WATERVILLE-TR03	UNATTENDED DISTRIB	69.00	13.20	
10	WATKINS-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	WAVERLY-TR01	UNATTENDED DISTRIB	69.00	12.50	
12	WELLS CREEK-TR01	UNATTENDED DISTRIB	69.00	12.50	
13	WESCOTT NATURAL GAS-TR01	UNATTENDED DISTRIB	69.00	2.40	
14	WEST BYRON-TR01	UNATTENDED DISTRIB	69.00	12.50	
15	WEST COON RAPIDS-TR01	UNATTENDED DISTRIB	115.00	34.50	
16	WEST COON RAPIDS-TR02	UNATTENDED DISTRIB	115.00	34.50	
17	WEST COON RAPIDS-TR03	UNATTENDED DISTRIB	34.50	23.00	
18	WEST FARIBAULT-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
19	WEST FARIBAULT-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
20	WEST FARIBAULT-TR03	UNATTENDED DISTRIB	69.00	13.80	
21	WEST FARIBAULT-TR07	UNATTENDED DISTRIB	69.00	13.80	
22	WEST HASTINGS-TR01	UNATTENDED DISTRIB	115.00	12.50	
23	WEST HASTINGS-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
24	WEST NEW ULM-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
25	WEST RIVER RD-TR01	UNATTENDED DISTRIB	115.00	13.80	
26	WEST RIVER RD-TR02	UNATTENDED DISTRIB	115.00	13.80	
27	WEST RIVER RD-TR03	UNATTENDED DISTRIB	115.00	13.80	
28	WEST SIOUX FALLS-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
29	WEST SIOUX FALLS-TR07	UNATTENDED DISTRIB	115.00	13.80	
30	WEST SIOUX FALLS-TR08	UNATTENDED DISTRIB	115.00	13.80	
31	WEST WACONIA-TR01	UNATTENDED DISTRIB	115.00	34.50	
32	WEST WACONIA-TR02	UNATTENDED DISTRIB	115.00	13.80	
33	WESTERN-TR01	UNATTENDED DISTRIB	115.00	13.80	
34	WESTERN-TR02	UNATTENDED DISTRIB	115.00	13.80	
35	WESTGATE-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
36	WESTGATE-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
37	WESTGATE-TR03	UNATTENDED DISTRIB	115.00	13.80	
38	WESTGATE-TR04	UNATTENDED DISTRIB	115.00	13.80	
39	WESTGATE-TR05	UNATTENDED DISTRIB	115.00	34.50	
40	WESTGATE-TR06	UNATTENDED DISTRIB	115.00	34.50	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	WESTPORT-TR01X,TR01Y	UNATTENDED DISTRIB	69.00	7.50	
2	WILLIAMS BROS PIPE-TR01	UNATTENDED DISTRIB	115.00	13.80	
3	WILLIAMS BROS PIPE-TR02	UNATTENDED DISTRIB	23.00	4.00	
4	WILLIAMS BROS PIPE-TR03	UNATTENDED DISTRIB	115.00	23.00	
5	WILLIAMS BROS PIPE-TR01B	UNATTENDED DISTRIB	15.00	13.80	
6	WILMARTH-TR06	UNATTENDED TRANSM	115.00	69.00	13.80
7	WILMARTH-TR07	UNATTENDED TRANSM	115.00	69.00	13.80
8	WILMARTH-TR08	UNATTENDED TRANSM	115.00	69.00	13.80
9	WILMARTH-TR09	UNATTENDED TRANSM	345.00	161.00	13.80
10	WILMARTH-TR10	UNATTENDED TRANSM	345.00	115.00	13.80
11	WILSON-TR03	UNATTENDED DISTRIB	115.00	13.80	
12	WILSON-TR04	UNATTENDED DISTRIB	115.00	13.80	
13	WILSON-TR05	UNATTENDED DISTRIB	115.00	13.80	
14	WINONA-TR01	UNATTENDED DISTRIB	69.00	13.80	
15	WINONA-TR02	UNATTENDED DISTRIB	69.00	13.80	
16	WINONA-TR03	UNATTENDED DISTRIB	69.00	13.80	
17	WINSTED-TR01	UNATTENDED DISTRIB	69.00	69.00	13.80
18	WINTHROP-TR01	UNATTENDED DISTRIB	69.00	12.50	
19	WOBEGON TRAIL-TR01	UNATTENDED DISTRIB	69.00	12.50	
20	WOODBURY-TR01	UNATTENDED DISTRIB	115.00	34.50	
21	WOODBURY-TR02	UNATTENDED DISTRIB	115.00	34.50	
22	WYOMING-TR01	UNATTENDED DISTRIB	115.00	12.50	
23	WYOMING-TR02	UNATTENDED DISTRIB	115.00	12.50	
24	YANKEE-TR01	UNATTENDED TRANSM	115.00	34.50	13.80
25	YANKEE-TR02	UNATTENDED TRANSM	115.00	34.50	13.80
26	YELLOW MEDICINE-TR01	UNATTENDED DISTRIB	69.00	34.50	
27	YOUNG AMERICA-TR01	UNATTENDED DISTRIB	69.00	13.80	
28	YOUNG AMERICA-TR02	UNATTENDED DISTRIB	69.00	13.80	
29	ZUMBRO FALLS-TR01	UNATTENDED DISTRIB	69.00	12.50	
30	ZUMBROTA-TR01	UNATTENDED DISTRIB	69.00	12.50	
31					
32					
33	Count TTL Transformer Banks	590			
34	Count TTL Transformers In Service	642			
35	TTL MVA In Service	39,739			
36	Count TTL Substations with Transformers	321			
37	Count TTL Substations without Transformer	28			
38	Count TTL Substations	349			
39	Count TTL Spares	35			
40					

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Spare Transformers				
2					
3	BROOK-TRSPR	N/A	34.50	4.16	
4	CLARKS GROVE-TRSPR	N/A	69.00	2.40	
5	CANISTOTA JUNCTION-TRST04	N/A	13.80	12.50	
6	EDINA-TRS013	N/A	13.80	0.48	
7	EDINA-TRS014	N/A	13.80	0.48	
8	EDINA-TRS015	N/A	13.80	0.48	
9	EDINA-TRS021	N/A	13.80	0.21	
10	EDINA-TRS022	N/A	13.80	0.21	
11	EDINA-TRS031	N/A	13.80	0.21	
12	EDINA-TRS032	N/A	13.80	0.21	
13	EDINA-TRS041	N/A	13.80	0.48	
14	EDINA-TRS042	N/A	13.80	0.48	
15	EMERY-TRSPR	N/A	34.50	4.36	
16	GLENWOOD-TRSPR1	N/A	34.50	2.45	
17	HUGO-TRG-CTR	N/A	115.00	14.00	
18	LINDE	N/A	115.00	14.00	
19	MAPLE GROVE	N/A	345.00	161.00	14.00
20	MAPLE GROVE	N/A	345.00	115.00	35.00
21	MAPLE GROVE	N/A	161.00	115.00	14.00
22	MAPLE GROVE	N/A	115.00	35.00	
23	MAPLE GROVE	N/A	69.00	14.00	
24	MAPLE GROVE	N/A	69.00	14.00	
25	MAPLE GROVE	N/A	69.00	14.00	
26	MAPLE GROVE	N/A	69.00	13.00	
27	MAPLE GROVE	N/A	69.00	13.00	
28	MAPLE GROVE	N/A	14.00	5.00	
29	MINNESOTA VALLEY-TRSPR	N/A	69.00	13.80	
30	MINNESOTA VALLEY	N/A	230.00	115.00	15.00
31	MINNESOTA VALLEY	N/A	230.00	115.00	15.00
32	MINNESOTA VALLEY	N/A	230.00	115.00	15.00
33	PAYNESVILLE TRANSM SUB-TRSPR	N/A	34.50	12.50	
34	PAYNESVILLE TRANSM SUB	N/A	115.00	69.00	13.00
35	PAYNESVILLE TRANSM SUB	N/A	115.00	69.00	13.00
36	PORTAL PIPELINE (MINOT)	N/A	14.00	5.00	
37	RED RIVER	N/A	115.00	25.00	
38					
39					
40					

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SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
448	1					1
300	1					2
14	1					3
70	1					4
70	1					5
25	1					6
25	1					7
47	1					8
47	1					9
11	1					10
6	1					11
70	1					12
70	1					13
70	1					14
2	3					15
7	1					16
14	1					17
70	1					18
70	1					19
70	1					20
70	1					21
6	1					22
1	3					23
14	1					24
4	1					25
14	1					26
28	1					27
25	1					28
48	1					29
48	1					30
28	1					31
6	1					32
5	1					33
4	1					34
7	1					35
10	1					36
3	1					37
9	1					38
25	1					39
25	1					40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
336	1					1
336	1					2
47	1					3
448	1					4
448	1					5
28	1					6
25	1					7
3	3					8
6	1					9
1	1					10
3	1					11
120	1					12
120	1					13
7	1					14
11	1					15
2	1					16
8	1					17
3	3					18
11	1					19
11	1					20
5	1					21
1	3					22
14	1					23
14	1					24
70	1					25
70	1					26
50	2					27
47	1					28
1	1					29
47	1					30
47	1					31
20	1					32
23	1					33
2	1					34
120	1					35
120	1					36
120	1					37
25	1					38
25	1					39
37	1					40

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
70	1					1
47	1					2
448	1					3
1203	3					4
1203	3					5
7	1					6
14	1					7
3	1					8
7	1					9
11	1					10
9	1					11
112	1					12
187	1					13
25	1					14
47	1					15
672	1					16
672	1					17
47	1					18
47	1					19
14	1					20
14	1					21
47	1					22
47	1					23
28	1					24
10	3					25
28	1					26
25	1					27
22	1					28
14	1					29
14	1					30
7	1					31
6	1					32
63	1					33
63	1					34
63	1					35
28	1					36
28	1					37
	2					38
11	1					39
5	1					40

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SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
14	1					1
8	1					2
8	1					3
47	1					4
70	1					5
47	1					6
12	1					7
28	1					8
5	1					9
47	1					10
47	1					11
47	1					12
11	1					13
28	1					14
28	1					15
1	1					16
47	1					17
47	1					18
51	1					19
448	1					20
448	1					21
2	1					22
70	1					23
70	1					24
70	1					25
70	1					26
70	1					27
47	1					28
25	1					29
70	1					30
47	1					31
448	1					32
2	3					33
7	1					34
7	1					35
	3					36
19	1					37
11	1					38
14	1					39
14	1					40

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
14	1					1
14	1					2
11	1					3
120	1					4
120	1					5
28	1					6
11	1					7
84	1					8
84	1					9
84	1					10
84	1					11
3	1					12
168	1					13
70	1					14
47	1					15
47	1					16
5	1					17
2	1					18
4	1					19
28	1					20
28	1					21
5	1					22
3	1					23
112	1					24
28	1					25
70	1					26
47	1					27
70	1					28
28	1					29
28	1					30
14	1					31
5	1					32
28	1					33
28	1					34
47	1					35
47	1					36
47	1					37
47	1					38
47	1					39
47	1					40

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
70	1					1
12	1					2
47	1					3
2	1					4
5	1					5
4	1					6
70	1					7
70	1					8
28	1					9
28	1					10
	3					11
2	1					12
336	1					13
3	1					14
3	1					15
42	1					16
47	1					17
25	1					18
28	1					19
1	3					20
14	1					21
70	1					22
70	1					23
47	1					24
47	1					25
47	1					26
47	1					27
6	1					28
6	1					29
63	1					30
63	1					31
550	1					32
14	1					33
14	1					34
14	1					35
14	1					36
3	1					37
2	1					38
47	1					39
47	1					40

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
47	1					1
47	1					2
47	1					3
47	1					4
47	1					5
50	1					6
448	1					7
450	1					8
11	1					9
1	1					10
28	1					11
28	1					12
7	1					13
4	1					14
28	1					15
47	1					16
46	1					17
15	1					18
15	1					19
11	1					20
5	1					21
28	1					22
70	1					23
336	1					24
70	1					25
112	1					26
67	1					27
14	1					28
9	1					29
47	1					30
47	1					31
70	1					32
47	1					33
42	1					34
50	1					35
30	1					36
50	1					37
11	1					38
8	1					39
11	1					40

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
11	1					1
47	1					2
47	1					3
12	1					4
28	1					5
47	1					6
28	1					7
4	1					8
70	1					9
270	1					10
13	1					11
47	1					12
3	1					13
70	1					14
70	1					15
7	1					16
187	1					17
187	1					18
6	1					19
4	1					20
5	1					21
28	1					22
70	1					23
47	1					24
3	1					25
6	1					26
5	1					27
5	1					28
4	1					29
70	1					30
70	1					31
70	1					32
2	1					33
3	1					34
63	1					35
63	1					36
63	1					37
70	1					38
	1					39
28	1					40

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
2	1					1
8	1					2
14	1					3
100	1					4
167	1					5
47	1					6
47	1					7
6	1					8
5	1					9
336	1					10
300	1					11
5	1					12
70	1					13
70	1					14
47	1					15
14	1					16
9	1					17
5	1					18
28	1					19
28	1					20
3	2					21
47	1					22
47	1					23
120	1					24
120	1					25
672	1					26
672	1					27
47	1					28
47	1					29
5	1					30
5	1					31
672	1					32
25	1					33
28	1					34
50	1					35
28	1					36
17	1					37
28	1					38
47	1					39
47	1					40

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
47	1					1
47	1					2
12	1					3
3	1					4
70	1					5
70	1					6
25	1					7
25	1					8
47	1					9
240	3					10
240	3					11
9	1					12
70	1					13
47	1					14
47	1					15
336	1					16
3	1					17
5	1					18
5	1					19
14	1					20
7	1					21
7	1					22
9	1					23
9	1					24
6	1					25
25	1					26
25	1					27
4	1					28
224	1					29
70	1					30
70	1					31
336	1					32
336	1					33
28	1					34
448	1					35
38	1					36
38	1					37
3	1					38
47	1					39
91	1					40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
91	1					1
25	1					2
15	1					3
47	1					4
336	1					5
448	1					6
448	1					7
17	1					8
17	1					9
7	1					10
6	1					11
14	1					12
28	1					13
5	1					14
47	1					15
47	1					16
15	1					17
15	1					18
8	1					19
47	1					20
47	1					21
47	1					22
47	1					23
70	1					24
	3					25
5	1					26
4	3					27
3	1					28
14	1					29
7	1					30
70	1					31
15	1					32
28	1					33
14	1					34
38	1					35
38	1					36
	1					37
28	1					38
28	1					39
112	1					40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
336	1					1
15	1					2
15	1					3
448	1					4
187	1					5
187	1					6
25	1					7
28	1					8
28	1					9
28	1					10
14	1					11
47	1					12
47	1					13
28	1					14
47	1					15
100	1					16
1	1					17
7	1					18
7	1					19
6	1					20
28	1					21
28	1					22
70	1					23
70	1					24
38	1					25
1	3					26
112	1					27
336	1					28
448	1					29
448	1					30
14	1					31
4	1					32
5	1					33
5	1					34
42	1					35
42	1					36
4	1					37
70	1					38
70	1					39
70	1					40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
70	1					1
5	1					2
6	1					3
47	1					4
47	1					5
28	1					6
47	1					7
11	1					8
70	1					9
70	1					10
10	3					11
10	3					12
10	3					13
10	3					14
10	3					15
10	3					16
47	1					17
47	1					18
47	1					19
672	1					20
672	1					21
4	1					22
5	1					23
5	1					24
70	1					25
70	1					26
70	1					27
70	1					28
70	1					29
70	1					30
28	1					31
	1					32
4	1					33
3	1					34
11	1					35
15	1					36
22	1					37
10	1					38
2	3					39
38	1					40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
2	1					1
28	1					2
14	1					3
28	1					4
7	1					5
11	1					6
5	1					7
2	1					8
3	1					9
2	1					10
4	1					11
5	1					12
6	1					13
11	1					14
70	1					15
70	1					16
28	1					17
70	1					18
67	1					19
22	1					20
7	1					21
28	1					22
112	1					23
112	1					24
70	1					25
70	1					26
70	1					27
38	1					28
70	1					29
70	1					30
	1					31
42	1					32
70	1					33
70	1					34
42	1					35
25	1					36
70	1					37
70	1					38
70	1					39
70	1					40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
	2					1
8	1					2
9	1					3
9	1					4
3	1					5
38	1					6
38	1					7
70	1					8
448	1					9
448	1					10
70	1					11
70	1					12
42	1					13
22	1					14
22	1					15
25	1					16
11	1					17
6	1					18
5	1					19
47	1					20
47	1					21
28	1					22
28	1					23
120	1					24
120	1					25
14	1					26
9	1					27
11	1					28
4	1					29
14	1					30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
						1
						2
1		1				3
2		1				4
5		1				5
2		1				6
2		1				7
2		1				8
1		1				9
1		1				10
1		1				11
1		1				12
1		1				13
1		1				14
1		1				15
3		1				16
3		1				17
7		1				18
336		1				19
448		1				20
187		1				21
70		1				22
22		1				23
11		1				24
4		1				25
4		1				26
14		1				27
5		1				28
4		1				29
112		1				30
50		1				31
50		1				32
3		1				33
47		1				34
47		1				35
5		1				36
47		1				37
						38
						39
						40

Name of Respondent Northern States Power Company (Minnesota)		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report (Mo, Da, Yr) 04/11/2016		Year/Period of Report End of 2015/Q4	
TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES							
1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies. 2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general". 3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.							
Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)			
1	Non-power Goods or Services Provided by Affiliated						
2	Company labor, benefits, and related payments	NSP Wisconsin	see note	167,933			
3	Interchange agreement	NSP Wisconsin	557 and 566	163,254,945			
4	Services provided by Xcel Energy Services Inc.	Xcel Energy Services Inc.	see note				
5	Advances from Affiliates	NSP Nuclear Corp.	233	-90,000			
6	Insurance premium payments for primary casualty	Xcel Energy Services Inc.	see note	22,557,646			
7	general liability, primary property, workers						
8	compensation, and global property						
9	Receipts from Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	-385,900,000			
10	Contribution of capital	Xcel Energy Inc.	207	-347,304,401			
11	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	-294,500,000			
12							
13							
14							
15							
16							
17							
18							
19							
20	Non-power Goods or Services Provided for Affiliate						
21	Company labor, benefits, and related payments	NSP Wisconsin	see note	-13,792,711			
22	Interchange agreement	NSP Wisconsin	456	-473,098,693			
23	Transformers	NSP Wisconsin	E107	-304,493			
24	Repayments under Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	294,500,000			
25	Investments in Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	385,900,000			
26	Dividends on common stock	Xcel Energy Inc.	215/216	259,140,525			
27	Advances to Affiliates	NSP Nuclear Corp.	233	140,000			
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 2 Column: c

107	\$	113,144
108		15,620
408.1		2,430
542		6,176
543		1,588
544		11,213
553		790
903		135
920		6,476
925		274
926		10,087
	\$	<u>167,933</u>

Schedule Page: 429 Line No.: 4 Column: c

Service Function Group	FERC Group	Total
Accounting, Financial Reporting & Taxes	107-CWIP	2,409,499
	163-Stores Exp	158,810
	184-Clearing	1,473
	186-Misc Deferred Debits	98,469
	408-409-Taxes	1,259,007
	417-421-Other Income	(44,211)
	426.1-426.5-Other Income Deductions	(18,590)
	430-431-Interest Charges	187,277
	500-514-Steam Power Generation	167,897
	517-532-Nuclear Power Generation	16,015
	535-545-Hydraulic Power Generation	351
	546-557-Other Power Generation	111,910
	560-573-Transmission Expenses	336,140
	580-598-Distribution Expenses	16,485
	710-742-Manufactured Gas Production	4,165
	807-813-Other Gas Supply Expenses	37,302
	850-870-Transmission Expenses	175
	871-893-Distribution Expenses	35,494
	920-935-Administrative and General Expense	15,489,341
Accounting, Financial Reporting & Taxes Total		20,267,009
Aviation Services	408-409-Taxes	25,429
	560-573-Transmission Expenses	332
	920-935-Administrative and General Expense	2,116,036
Aviation Services Total		2,141,797
Business Systems	107-CWIP	85,856,823
	108-Accum Dep	8,323
	182.3-Reg Assets	825,360
	408-409-Taxes	893,835
	417-421-Other Income	77,547
	426.1-426.5-Other Income Deductions	30,262

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

	500-514-Steam Power Generation	1,700,849
	517-532-Nuclear Power Generation	5,613,687
	535-545-Hydraulic Power Generation	4,683
	546-557-Other Power Generation	346,473
	560-573-Transmission Expenses	5,133,000
	580-598-Distribution Expenses	3,124,556
	807-813-Other Gas Supply Expenses	3,124
	814-826-Underground Storage Expenses	9,264
	840-843.9-Other Storage Expenses	24,066
	850-870-Transmission Expenses	122,351
	871-893-Distribution Expenses	1,471,983
	901-905-Customer Accounts Expenses	6,366,436
	908-909-Customer Service and Informational Expenses	38,581
	912 Sales Expenses	23
	920-935-Administrative and General Expense	91,613,772
Business Systems Total		203,264,998
Claims Services	408-409-Taxes	38,429
	920-935-Administrative and General Expense	733,493
Claims Services Total		771,922
Corporate Communications	107-CWIP	5,637
	182.3-Reg Assets	584,785
	186-Misc Deferred Debits	117
	254-Reg Liab	185
	408-409-Taxes	88,212
	417-421-Other Income	1,013
	426.1-426.5-Other Income Deductions	2,780
	500-514-Steam Power Generation	61
	517-532-Nuclear Power Generation	7
	560-573-Transmission Expenses	(44)
	580-598-Distribution Expenses	231
	710-742-Manufactured Gas Production	5,924
	850-870-Transmission Expenses	73
	901-905-Customer Accounts Expenses	340
	908-909-Customer Service and Informational Expenses	550,770
	920-935-Administrative and General Expense	4,544,657
Corporate Communications Total		5,784,748
Corporate Strategy & Business Development	408-409-Taxes	58,286
	426.1-426.5-Other Income Deductions	113
	546-557-Other Power Generation	13,878
	920-935-Administrative and General Expense	1,301,795
Corporate Strategy & Business Development Total		1,374,072
Customer Service	182.3-Reg Assets	1,250,444
	254-Reg Liab	489,467

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Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

	408-409-Taxes	981,069
	417-421-Other Income	1,574
	426.1-426.5-Other Income Deductions	23,067
	901-905-Customer Accounts Expenses	14,669,204
	908-909-Customer Service and Informational Expenses	372,503
	920-935-Administrative and General Expense	3,782,838
Customer Service Total		21,570,166
Employee Communications	107-CWIP	67,082
	408-409-Taxes	63,036
	426.1-426.5-Other Income Deductions	46
	908-909-Customer Service and Informational Expenses	33
	920-935-Administrative and General Expense	1,297,684
Employee Communications Total		1,427,881
Energy Delivery - Engineering/Design	107-CWIP	26,111,617
	108-Accum Dep	65,663
	408-409-Taxes	418,169
	417-421-Other Income	16,077
	426.1-426.5-Other Income Deductions	8,156
	500-514-Steam Power Generation	13,776
	546-557-Other Power Generation	5,484
	560-573-Transmission Expenses	6,599,679
	580-598-Distribution Expenses	1,473,610
	850-870-Transmission Expenses	996,300
	871-893-Distribution Expenses	17,177
	901-905-Customer Accounts Expenses	(6)
	908-909-Customer Service and Informational Expenses	22
	920-935-Administrative and General Expense	1,851,529
Energy Delivery - Engineering/Design Total		37,577,253
Energy Delivery Construction, Operations & Maintenance (COM)	107-CWIP	3,514,622
	408-409-Taxes	510,335
	426.1-426.5-Other Income Deductions	67,178
	560-573-Transmission Expenses	5,304,768
	580-598-Distribution Expenses	1,891,784
	840-843.9-Other Storage Expenses	18,476
	850-870-Transmission Expenses	680,765
	871-893-Distribution Expenses	366,180
	901-905-Customer Accounts Expenses	1,251
	908-909-Customer Service and Informational Expenses	239
	920-935-Administrative and General Expense	2,934,671
Energy Delivery Construction, Operations & Maintenance (COM) Total		15,290,269
Energy Delivery Marketing	408-409-Taxes	10,864

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

	560-573-Transmission Expenses	9,387
	580-598-Distribution Expenses	147,088
	920-935-Administrative and General Expense	39,460
Energy Delivery Marketing Total		206,799
Energy Markets - Fuel Procurement	408-409-Taxes	83,368
	500-514-Steam Power Generation	742,797
	546-557-Other Power Generation	101,987
	807-813-Other Gas Supply Expenses	293,566
	920-935-Administrative and General Expense	588,691
Energy Markets - Fuel Procurement Total		1,810,409
Energy Markets Regulated Trading & Marketing	107-CWIP	25,790
	408-409-Taxes	341,334
	426.1-426.5-Other Income Deductions	12,019
	535-545-Hydraulic Power Generation	1,545
	546-557-Other Power Generation	4,006,573
	560-573-Transmission Expenses	464,847
	575.1-575.8-Regional Market Expenses	314,475
	901-905-Customer Accounts Expenses	324
	908-909-Customer Service and Informational Expenses	11,211
	920-935-Administrative and General Expense	2,220,611
Energy Markets Regulated Trading & Marketing Total		7,398,729
Energy Supply Business Resources	107-CWIP	1,287,341
	108-Accum Dep	18,222
	408-409-Taxes	667,527
	426.1-426.5-Other Income Deductions	6,435
	500-514-Steam Power Generation	9,800,831
	517-532-Nuclear Power Generation	323,917
	535-545-Hydraulic Power Generation	11,734
	546-557-Other Power Generation	554,222
	560-573-Transmission Expenses	1,396
	580-598-Distribution Expenses	183
	920-935-Administrative and General Expense	4,028,666
Energy Supply Business Resources Total		16,700,474
Energy Supply Engineering & Environmental	107-CWIP	(27,371,095)
	108-Accum Dep	844,529
	182.3-Reg Assets	1,310,997
	408-409-Taxes	239,719
	417-421-Other Income	775
	426.1-426.5-Other Income Deductions	17,119
	500-514-Steam Power Generation	3,000,524
	517-532-Nuclear Power Generation	139,936
	535-545-Hydraulic Power Generation	1,744
	546-557-Other Power Generation	133,876

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

	560-573-Transmission Expenses	50,323
	580-598-Distribution Expenses	125,804
	710-742-Manufactured Gas Production	23,699
	850-870-Transmission Expenses	11,144
	871-893-Distribution Expenses	44,135
	901-905-Customer Accounts Expenses	4
	920-935-Administrative and General Expense	1,912,778
Energy Supply Engineering & Environmental Total		(19,513,989)
Executive Management Services	107-CWIP	(2)
	408-409-Taxes	164,342
	426.1-426.5-Other Income Deductions	268,483
	500-514-Steam Power Generation	3
	546-557-Other Power Generation	177,948
	580-598-Distribution Expenses	3
	850-870-Transmission Expenses	187,580
	871-893-Distribution Expenses	13,351
	901-905-Customer Accounts Expenses	18
	908-909-Customer Service and Informational Expenses	1,168
	920-935-Administrative and General Expense	5,970,980
Executive Management Services Total		6,783,874
Facilities & Real Estate	107-CWIP	616,527
	184-Clearing	13,997,950
	408-409-Taxes	49,431
	426.1-426.5-Other Income Deductions	22,013
	500-514-Steam Power Generation	168,328
	517-535-Nuclear Power Generation	131
	535-545-Hydraulic Power Generation	593
	546-557-Other Power Generation	185,873
	560-573-Transmission Expenses	573,623
	580-598-Distribution Expenses	183,712
	850-870-Transmission Expenses	9,199
	871-893-Distribution Expenses	101,726
	920-935-Administrative and General Expense	11,313,913
Facilities & Real Estate Total		27,223,019
Facilities Administrative Services	107-CWIP	4,933
	184-Clearing	435,857
Facilities Administrative Services Total		440,790
Finance & Treasury	107-CWIP	398
	182.3-Reg Assets	12,102
	184-Clearing	(3,026)
	408-409-Taxes	225,362
	417-421-Other Income	(67,764)
	426.1-426.5-Other Income Deductions	3,763
	430-431-Interest Charges	24,123

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

	546-557-Other Power Generation	249,225
	920-935-Administrative and General Expense	12,155,069
Finance & Treasury Total		12,599,252
Fleet	107-CWIP	88,058
	163-Stores Exp	269
	184-Clearing	917,607
	920-935-Administrative and General Expense	152,431
Fleet Total		1,158,365
Government Affairs	408-409-Taxes	63,970
	426.1-426.5-Other Income Deductions	623,689
	920-935-Administrative and General Expense	1,323,166
Government Affairs Total		2,010,825
Human Resources	107-CWIP	800,533
	108-Accum Dep	106,001
	408-409-Taxes	582,967
	426.1-426.5-Other Income Deductions	44,655
	500-514-Steam Power Generation	6,768
	517-532-Nuclear Power Generation	932,270
	560-573-Transmission Expenses	294,608
	580-598-Distribution Expenses	762,049
	850-870-Transmission Expenses	611,101
	908-909-Customer Service and Informational Expenses	200,030
	920-935-Administrative and General Expense	26,055,043
Human Resources Total		30,396,025
Internal Audit	254-Reg Liab	15
	408-409-Taxes	50,104
	426.1-426.5-Other Income Deductions	132
	920-935-Administrative and General Expense	1,417,993
Internal Audit Total		1,468,244
Investor Relations	408-409-Taxes	15,648
	426.1-426.5-Other Income Deductions	2,082
	920-935-Administrative and General Expense	1,085,022
Investor Relations Total		1,102,752
Legal	107-CWIP	120,740
	186-Misc Deferred Debits	2,491
	408-409-Taxes	304,786
	426.1-426.5-Other Income Deductions	28,327
	500-514-Steam Power Generation	213
	517-532-Nuclear Power Generation	241,088
	546-557-Other Power Generation	1,588
	560-573-Transmission Expenses	(374)
	580-598-Distribution Expenses	838
	710-742-Manufactured Gas Production	71,522
	920-935-Administrative and General Expense	7,310,329
Legal Total		8,081,548

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Marketing & Sales	182.3-Reg Assets	12,341,772
	186-Misc Deferred Debits	44,334
	408-409-Taxes	127,410
	417-421-Other Income	3,635
	426.1-426.5-Other Income Deductions	68,629
	901-905-Customer Accounts Expenses	3,137
	908-909-Customer Service and Informational Expenses	1,726,211
	920-935-Administrative and General Expense	3,480,411
Marketing & Sales Total		17,795,539
Payment & Reporting	408-409-Taxes	20,322
	920-935-Administrative and General Expense	595,692
Payment & Reporting Total		616,014
Payroll	107-CWIP	3,580
	408-409-Taxes	50,335
	426.1-426.5-Other Income Deductions	5,054
	517-532-Nuclear Power Generation	3,023
	920-935-Administrative and General Expense	1,047,976
Payroll Total		1,109,968
Rates & Regulation	107-CWIP	36,199
	408-409-Taxes	169,694
	426.1-426.5-Other Income Deductions	2,647
	901-905-Customer Accounts Expenses	161
	920-935-Administrative and General Expense	3,309,438
Rates & Regulation Total		3,518,139
Receipts Processing	182.3-Reg Assets	480
	408-409-Taxes	20,849
	901-905-Customer Accounts Expenses	369,920
	920-935-Administrative and General Expense	211,215
Receipts Processing Total		602,464
Supply Chain	107-CWIP	1,641,257
	108-Accum Dep	186,843
	163-Stores Exp	5,343,572
	184-Clearing	978,434
	408-409-Taxes	6,161
	426.1-426.5-Other Income Deductions	56,528
	517-532-Nuclear Power Generation	248
	560-573-Transmission Expenses	52,919
	580-598-Distribution Expenses	4,194
	850-870-Transmission Expenses	1,747
	871-893-Distribution Expenses	1,837
	920-935-Administrative and General Expense	102,269
Supply Chain Total		8,376,009
Grand Total		439,355,364

Name of Respondent	This Report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2016	Year/Period of Report 2015/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Services provided by Xcel Energy Services, Inc. are directly charged when only one company is benefiting from the service provided from the service provided. Otherwise, expenses are allocated based on methodologies described in FERC Form 60.

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165	\$ 15,391,555
232	5,409,270
253	912,196
107	393,680
124	329,059
143	104,386
925	17,500
	<u>\$ 22,557,646</u>

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107	\$ (13,358,265)
108	(87,474)
163	(22,526)
184	(92,793)
408.1	(10,306)
500	(127)
501	(17,355)
506	(8,345)
511	(4,759)
512	(98,533)
513	(3,085)
514	(31,075)
539	(13,922)
544	(307)
548	6
553	(2,112)
560	(46)
570	(3,999)
580	(7)
582	(13,744)
588	(4,825)
841	(10,622)
874	(981)
903	(7)
908	(277)
925	(2,018)
926	(5,207)
	<u>\$ (13,792,711)</u>

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