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DIRECT TESTIMONY AND SCHEDULES
DR. KARL A. MCDERMOTT

DIRECT TESTIMONY OF
KARL A. MCDERMOTT, PH.D

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company,
a Minnesota Corporation and Wholly Owned Subsidiary of Xcel Energy Inc.
For the Authority to Increase Rates for
Natural Gas Service in North Dakota

December 15, 2006

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1 Before co-founding the CRS, I worked in numerous capacities including positions on the
2 staff of the ICC, the NARUC-sponsored National Regulatory Research Institute (NRRI) at
3 the Ohio State University and Argonne National Laboratory. I have also taught graduate
4 and undergraduate level economics courses, including regulatory economics, at Illinois
5 State University and undergraduate economics courses at the Ohio State University, the
6 University of Illinois at Urbana-Champaign and Parkland College in Champaign, Illinois.

7 I am currently on the faculty of the Institute for Public Utilities at Michigan State
8 University where I am an invited lecturer at the Institute's annual Regulatory Studies
9 Program. I have also been an invited lecturer on rate-of-return issues at NARUC and
10 numerous other regulatory and public utility finance conferences around the country. I
11 have testified before several state regulatory commissions, as well as before the Federal
12 Energy Regulatory Commission, the Federal Communications Commission and the Iowa
13 and Illinois General Assemblies on issues concerning public utility regulation.

14 I received a B.A. in Economics from Indiana University of Pennsylvania, an M.A. in Public
15 Utility Economics at the University of Wyoming, and a Ph.D. in Economics at the
16 University of Illinois at Urbana-Champaign.

17 Q. Have you ever testified in North Dakota before?

18 A. Yes. I previously testified on behalf of Northern States Power Company, ("Xcel Energy" or
19 "the Company"), a Minnesota corporation and wholly owned subsidiary of Xcel Energy
20 Inc. in its last general natural gas rate case concerning the appropriate cost of equity (Case
21 No. PU-400-04-578). I also testified in Case Nos. PU-400-04-578, PU-400-00-195 and PU-
22 401-00-36 on behalf of the Company as well as Otter Tail Power Company regarding
23 performance-based-ratemaking mechanisms for their electric utility operations in North
24 Dakota.

25 Q. Please describe your practice at NERA.

26 A. Since joining NERA in 1999, I have been retained by both public and private interests to
27 provide my expert analysis of numerous public policy issues that face regulators and
28 utilities. My domestic practice consists of advisory work for clients on issues pertaining to

1 regulation and market conditions and providing expert opinion on issues of public policy
2 toward regulated utilities. My international practice consists of advising governments and
3 utilities on the appropriate course for public policy through the transition from centralized
4 planning toward a more liberalized economy and utility industry. This includes training
5 newly-formed regulatory commission staff and commissioners in best practices of
6 regulation. My practice has allowed me to address issues from electric restructuring, firm
7 governance and mergers, rate design and the applications of competitive principles toward
8 regulated utilities. A more detailed description of my academic and professional
9 experience can be found in my curriculum vitae attached to this testimony as Exhibit ____
10 (KAM-1), Schedule 1.

11 Q. What is the purpose of your testimony?

12 A. I have been asked by the Company to conduct an independent assessment of the fair and
13 reasonable return on common equity capital employed in the natural gas utility operations
14 of Xcel Energy in North Dakota. In forming my professional opinion on this issue, I have
15 taken into account the need to balance the fair treatment of ratepayers and the need to
16 attract capital and maintain financial integrity. In order to achieve these goals, the fair rate
17 of return on equity capital must be commensurate with the returns earned by firms with
18 comparable investment risk.

19 Q. What is your conclusion after your review of the facts and circumstances in this case?

20 A. As summarized on Exhibit____(KAM-1), Schedule 2, it is my opinion that a just and
21 reasonable return on common equity of 11.32 percent should be used in establishing Xcel
22 Energy's revenue requirement in this case. This ROE recommendation is based on the mid-
23 point of a range established using a four-company comparable group. This recommendation
24 is 29 basis points below the mid-point of a range established using a five-company
25 comparable group which includes Cascade Natural Gas. My recommendation is determined
26 through the use of both a discounted cash flow ("DCF") and a capital asset pricing model
27 ("CAPM") analysis.

28

1 Q. Please describe how your testimony is organized.

2 A. My testimony is organized as follows. In **Section II**, I discuss the theory and practice of
3 estimating the cost of capital, reviewing the appropriate standards for setting and describing
4 my rationale for employing the DCF and CAPM approaches. In **Section III**, I summarize
5 my findings and recommendation.

6 **II. COST OF CAPITAL ANALYSIS**

7 **A. Regulatory Principles**

8 Q. What is a utility's overall cost of capital?

9 A. A utility's overall cost of capital is the weighted average cost of capital (WACC). The
10 WACC is the sum of the costs of the components in the capital structure, *i.e.*, long term
11 debt, short term debt (if used in a utility's capital structure in the particular regulatory
12 jurisdiction), preferred stock, if any, and common equity, after each component is weighted
13 by its respective proportion of the utility's total capitalization. The Company's proposed
14 capital structure is discussed by Company witness Jeffrey Robinson.

15 Q. What is meant by the term fair rate of return?

16 A. Any business, whether regulated or unregulated, must be expected to earn enough profit to
17 compensate present investors for the risks incurred by providing capital to the firm if new
18 capital is to be attracted on reasonable terms. If new capital cannot be attracted on
19 reasonable terms, a business will have difficulty providing reliable and adequate service.
20 For a regulated utility, this opportunity to earn a fair return is critical as it has an obligation
21 to serve customers and, generally, is regulated with respect to exiting the business. In order
22 to compete in the global capital market, a utility must have the ability to pay investors their
23 opportunity cost of investing. If a utility cannot meet these requirements, investors will
24 simply put their money in an alternative investment.

25 Q. Please define the opportunity cost of capital.

1 A. The opportunity cost of capital is the future compensation that investors expect for taking
2 on the risks associated with a particular investment. This is also referred to as the investor's
3 required return. Investors have many opportunities or alternative investments of equal or
4 varying risk in which to invest their capital. Therefore, the opportunity cost of capital is
5 influenced by the competition for the limited capital funds between **all** potential users of
6 capital. Since the opportunity cost of capital is an expectation, one cannot directly observe
7 investors' required return; rather, it must be estimated based on market data.

8 Q. In setting rates, what is the allowed rate of return for a public utility?

9 A. The allowed rate of return is the allowed overall cost of capital (i.e., the allowed WACC)
10 that the Commission authorizes a utility to recover through rates. Note that the regulator
11 does not guarantee that the utility will recover the allowed rate of return; rather it is the
12 level that the utility has an opportunity to recover without the Commission resetting its rates
13 if its costs and sales reflect test year levels. The overall cost of capital should be based on
14 an appropriate capital structure and appropriate equity, preferred stock (if any), and debt
15 costs which, as I noted earlier, is discussed by Company witness Jeffrey Robinson.

16 Q. Why is it necessary to determine an appropriate overall cost of capital for a public utility?

17 A. Capital costs are similar to any other cost of doing business and must be recoverable
18 through the rates approved by the Commission. Allowing a utility the opportunity to
19 recover its appropriate capital costs will properly balance the interests of ratepayers and
20 investors. If the cost of capital is set too high, ratepayers will be burdened with excessive
21 rates. Conversely, if it is set too low, a utility's financial condition and its ability to provide
22 efficient, safe, adequate, and reliable service will be adversely affected. This will also
23 negatively affect ratepayers through reduced service quality. Therefore, ratepayers' and
24 investors' interests are best served by setting the allowed rate of return on rate base equal to
25 an appropriate overall cost of capital. As discussed above, Mr. Robinson provides
26 testimony describing the Company's test year capital structure and proposed overall cost of
27 capital.

1 **B. Cost of Equity Analysis**

2 **1. Overview**

3 Q. What regulatory principles should be followed in determining an appropriate cost of
4 common equity?

5 A. The determination of the cost of equity has been a central point of contention during the
6 evolution of modern regulation. The U.S. Supreme Court in the *Hope*¹ decision initiated the
7 period of modern regulation. In that case the Court established the traditional and current
8 standard for a fair and reasonable return stating:

9 ...the return to the equity owner should be *commensurate with returns on*
10 *investments in other enterprises having corresponding risks.* That return,
11 moreover, should be sufficient to assure confidence in the financial integrity of
12 the enterprise, so as to *maintain its credit and attract capital.* (Emphasis
13 added.)²

14 The Court, in effect, established two criteria which are inherently related. In order for a
15 firm to attract capital and maintain its financial integrity it must be able to offer the owners
16 of equity an opportunity to earn a return commensurate with firms of similar risks.
17 Otherwise the capital markets will direct their flow of capital to firms with lower risk but
18 the same return as the utility or to firms with a higher return and the same risk. This legal
19 concept is similar to the economic concept of opportunity cost that I discussed above. That
20 is, the Court recognized that there is an opportunity cost of investing money in a utility and
21 investors will require that the utility be allowed the opportunity to provide that level of
22 return or they will simply put their money elsewhere. Just as a firm pays the market wage to
23 obtain labor services (or any other inputs it must procure) it must pay the going market rate
24 (i.e., opportunity cost) for the use of investor's money if it is to attract the capital necessary
25 to operate its business.

¹ *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944).

² *Id.* at 603

1 Q. Are there any special characteristics of obtaining capital that make ascertaining its cost more
2 difficult?

3 A. As the *Hope* decision enumerated, the expected return that investors require to bear the risk
4 of investing in a utility must be identified. The appropriateness of a utility's cost of equity
5 is dependent upon company-specific factors such as an appropriate capital structure,
6 company-specific risk factors, and the financial condition of the Company. These
7 company-specific factors comprise a utility's business and financial risk. Business risk is a
8 term that refers to the uncertainty of income flows caused by the nature of a firm's
9 business, while financial risk refers to the uncertainty introduced by the method of
10 financing an investment (*e.g.*, debt usually requires fixed payments so having more debt
11 increases a firm's financial risk).³

12 The evolution of this "cost of capital" standard codified in *Hope* was clearly expounded by
13 Justice Brandeis in *Southwestern Bell*⁴ as early as 1923 where he noted:

14 The compensation which the Constitution guarantees an opportunity to earn is
15 the reasonable cost of conducting the business. Cost includes not only operating
16 expenses, but also capital charges. Capital charges cover the allowance, by way
17 of interest, for the use of the capital, whatever the nature of the security issued
18 therefore; the allowance for risk incurred; and enough more to attract capital.⁵

19 Thus, the compensation for the use of capital must recognize the risks⁶ and the ability to
20 attract capital in the competitive capital markets. And, since these capital markets are
21 competitive what we need to understand is the investor's perception of the opportunity

³ Frank. K. Reilly, *Investment Analysis and Portfolio Management*, 2nd ed. (Dryden Press: Chicago, 1985), p. 14

⁴ Missouri ex rel. *Southwestern Bell Tel. Co. v. Public Serv. Comm'n* 262 U.S. 276 (1923).

⁵ *Id.* at 291.

⁶ This recognition by the Supreme Court that risk must be compensated actually stretches back to at least 1909 in the *Willcox v. Consolidated Gas Co.* Case 212 U.S. 19 (1909) where the court said "Such compensation must depend greatly upon circumstance and locality; among other things, the amount of risk in the business is a most important factor... the rate expected and usually realized there upon investments of a somewhat similar nature with regard to the risks attending them." 212 U.S. at 48

1 costs of parting with his or her money. At roughly that same time the Court delineates what
2 it meant by this standard in the *Bluefield* case.⁷

3 In the *Bluefield* case, the U.S. Supreme Court defined the proper rate of return as follows:

4 A public utility is entitled to such rates as will permit it to earn a return on the
5 value of the property which it employs for the convenience of the public equal to
6 that generally being made at the same time and in the same general part of the
7 country on investments in other business undertakings which are attended by
8 corresponding risks and uncertainties, but it has no constitutional right to profits
9 such as are realized or anticipated in highly profitable enterprises or speculative
10 ventures. The return should be reasonably sufficient to assure confidence in the
11 financial soundness of the utility, and should be adequate under efficient and
12 economical management, to maintain and support its credit and enable it to raise
13 the money necessary for the proper discharge of its public duties.

14 The standards of *Bluefield* and *Hope* have been more recently affirmed by the Court in
15 *Duquesne*.⁸

16 Thus, investors' required returns create the basis by which the Commission should establish
17 a utility's allowed cost of equity. This can be established by examining the market-based
18 cost of common equity, as determined through an analysis of a group of companies that are
19 of comparable risk to Xcel Energy's regulated natural gas local distribution company
20 (LDC) operations in North Dakota. A return based on this comparable analysis should be
21 accepted as the allowed fair rate of return on common equity. As a result, rates for Xcel
22 Energy's customers will be established based on an approach that is consistent with sound
23 regulatory and financial principles.

24 In order to measure the opportunity cost of equity that is applicable to Xcel Energy's
25 regulated natural gas LDC operations in North Dakota, it is necessary to assemble a group
26 of gas utilities with publicly-traded stock that are representative, on average, of the business

⁷ *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia* (262 U.S. 679, 692-3, 1923)

⁸ *Duquesne Light Company v. Barasch*, 98 PUR 4th 253 (1989).

1 and financial risk faced by Xcel Energy’s regulated natural gas LDC operations in North
2 Dakota.

3 Q. Please describe the difficulties associated with cost of equity estimation?

4 A. Estimating the cost of equity has always been one of the most controversial issues in utility
5 ratemaking. This arises in part because, as noted above, the actual investor requirements are
6 not directly observable. Thus, it is very important to use financial methods, based on the
7 sound application of financial theory, which let the market “do the talking” as much as
8 possible.

9 Q. What methodologies did you employ to determine the cost of common equity?

10 A. For the purposes of determining the cost of common equity in this case, I will rely on both a
11 DCF and CAPM analysis as described in **Section II** of this testimony. I use the DCF and
12 CAPM analysis because the use of these two methodologies provides added assurance
13 regarding the appropriateness of my results.

14 To determine the appropriate cost of common equity, I first identified a peer group of
15 companies that are similar in risk to Xcel Energy’s regulated natural gas LDC operations in
16 North Dakota. I selected this group from the publicly-traded natural gas utilities that are
17 followed by Value Line. I then performed my cost of equity analysis on this group of
18 companies.

19 **2. Comparable Group**

20 Q. Why did you use a group of comparable companies in your cost of equity analysis?

21 A. The purpose of my testimony is to determine the cost of common equity of the Company’s
22 natural gas LDC operations in North Dakota. Xcel Energy’s North Dakota LDC operations
23 have no separate publicly traded common stock. It is therefore not possible to analyze
24 directly the opportunity cost of equity of Xcel Energy’s regulated natural gas LDC
25 operations in North Dakota. Also, a direct analysis of Xcel Energy’s regulated natural gas
26 LDC operations in North Dakota would raise the question of *circularity*: the outcome of a
27 rate case can have a meaningful effect on a regulated utility’s cash flows, which would

1 affect the valuation of the regulated utility's stock, which would affect its cost of equity
2 capital.⁹

3 A proxy group of comparable companies is used to estimate *indirectly* the cost of equity of
4 Xcel Energy's natural gas LDC operations in North Dakota. The use of a group of
5 companies that are comparable in terms of business and financial risk is consistent with the
6 *Hope* decision and provides a more reliable and objective estimate of the return on equity
7 required by the capital markets.

8 The DCF method renders a cost of capital estimate using the results for each company in
9 the proxy group. The results of any one company in the proxy group may be somewhat
10 high or low, but the use of an averaging process can develop a reasonable estimate of
11 market conditions.

12 A cost of equity estimate for a group of gas utilities that have comparable risk provides a
13 data source by which to determine a cost of equity estimate for these companies, or any
14 other company that is being analyzed. Exhibit ____ (KAM-1), Schedule 3 illustrates my
15 method for obtaining the comparable companies. This Schedule lists all of the publicly-
16 traded natural gas LDCs that are followed by Value Line and that:

- 17 1. Have not eliminated or reduced their common dividend during the most recent
18 eight quarters. A history of paying a common dividend is necessary for my DCF
19 analysis.
- 20 2. Receive 80 percent or more of their revenues from regulated utility operations.
21 Xcel Energy is a regulated gas LDC in North Dakota and therefore companies
22 that are highly diversified into non-regulated areas are screened out.
- 23 3. Have less than \$10 billion of equity capital.
- 24 4. Are not involved in a merger.

⁹ Roger Morin explains that "[t]he net result is that the cost of equity depends in part on anticipated regulatory action, since both components of K, yield and growth, are influenced by the regulatory process." See: Roger A. Morin, *Utilities' Cost of Capital* (Arlington, VA: PUR, 1984), pp 143-144.

1 A set of companies which passes these screens are appropriate for use in determining the
2 cost of common equity of Xcel Energy’s regulated natural gas LDC operations in North
3 Dakota and therefore are used in both my DCF and CAPM analyses.

4 Q. Previously you testified that Cascade Natural Gas (Cascade) should be included in the
5 comparable group for the Company (McDermott Direct, Case No. PU-400-04-578). Is
6 Cascade included in your final recommendation in this case?

7 A. I have included Cascade in one of my comparable groups reported in Exhibit____(KAM-1),
8 Schedule 2 Cascade is being acquired by MDU Resources Group. I generally exclude
9 merging companies from the comparable group because the stock price, growth rates and
10 other inputs to the DCF model may be distorted due to the merger. However, the Cascade
11 merger was announced on July 9, 2006 and the Value Line for Cascade was released shortly
12 thereafter on September 15, 2006. Further, Value Line’s most recent survey suggests that it
13 is treating Cascade as a stand alone entity (as not being affected by the merger), as shown in
14 **Table 1.**¹⁰

Table 1: The most recent Value Line edition for Cascade does not reflect the recent merger

Value Line Edition	2005	2009-2011	Average Growth (Percent)
June 16, 2006	\$ 0.82	\$ 1.60	14.30%
Merger Announced on July 9, 2006			
September 15, 2006	\$ 0.82	\$ 1.60	14.30%

Source: Value Line Investment Survey

15

16 Further, any increase in the price of the Cascade stock (in anticipation of the merger) would
17 have the effect of reducing the dividend yield and would thus not introduce an upward bias
18 in the cost of equity determination under the DCF model. Therefore, the concerns that

¹⁰ Value Line Investment Survey, Industry Report, September 15, 2006

1 typically apply to a company involved in a merger do not appear to be applicable to
2 Cascade. In Exhibit____(KAM-1), Schedule 2, I report results based on both including and
3 excluding Cascade. However, as indicated below, I have chosen to recommend an
4 appropriate cost of equity based on a comparable group that excludes Cascade. I report the
5 results of my analysis utilizing the comparable group including Cascade as a source of
6 additional information to support my recommendation.

7 Q. You had also included KeySpan, in your previous testimony concerning the appropriate
8 comparable group for the Company. Would you please explain why you did not include
9 KeySpan in this testimony?

10 A. The KeySpan merger was announced on February 27, 2006. Therefore, the most recent
11 Value Line for KeySpan reflects the consequences of the KeySpan merger, so I have not
12 included KeySpan in my analyses in this case.

13 **3. DCF Analysis**

14 Q. Please describe the DCF model used in determining the cost of common equity capital.

15 A. The DCF model provides a conceptually correct and straightforward approach for
16 determining the cost of equity capital. The DCF model is based on the fundamental
17 principle that the value of an asset is equal to the expected cash flows generated by that
18 asset, discounted by the investor-required rate of return. Specifically, the market value of
19 common stock is equal to the present value of the expected stream of future dividends.
20 While there are several forms of the DCF model, all versions of the DCF model are based
21 on the price of the stock today being determined by investors' expectations regarding future
22 cash flows. (Investors' expectations are formulated based on available public information
23 and therefore this theory is consistent with the semi-strong version of the EMH discussed
24 below.) Furthermore, the DCF model directly establishes a cost of equity capital based on
25 the investors' required rate of return rather than on historical earned returns.

26

27

1 Q. How are stock prices evaluated by investors?

2 A. Investors generally operate on the principle concept that a stock’s price should represent the
3 present value or discounted value of all future dividends that investors expect to receive. In
4 effect investors are taking into account the time value of money. In its most general form, a
5 discounted cash flow model captures this in the following formula:

6
$$P_o = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \dots + \frac{D_\infty}{(1+k)^\infty} \quad (1)$$

7 Where, P_o is today’s stock price; D_1 , D_2 , etc. are all future dividends and k is the discount
8 rate, or the investor’s required rate of return on equity. Equation (1) is simply a routine
9 present value calculation based on the assumption that the stock’s price is the present value
10 of all dividends expected to be paid in the future. If I make an additional assumption that
11 dividends are expected to grow at a constant rate g and further assume that k is strictly
12 greater than g , then equation (1) can be solved for k :

13
$$k = \frac{D_1}{P_o} + g \quad (2)$$

14 This equation is the familiar constant growth version of the DCF model for cost of equity
15 that I will employ in this testimony.

16 Q. Please describe the annual DCF model.

17 A. Exhibit____(KAM-1), Schedule 4 demonstrates that the annual required rate of return on
18 common equity for a firm that pays dividends annually may be determined by solving for
19 K_e in the following equation:

20
$$K_e = \frac{D_o(1+g)}{P_o} + g \quad (3)$$

21 Where:

22
23 $K_e \equiv$ the required rate of return on common equity;

24
25 $D_o \equiv$ the current annual dividend;

26

1 $P_0 \equiv$ the current market price; and,

2
3 $g \equiv$ the expected annual growth rate in dividends.
4

5 Q. Do utilities typically pay dividends on an annual basis?

6 A. No, they do not. Most U.S. utilities pay dividends on a quarterly basis, although dividend
7 increases typically occur no more than once per year.

8 Q. Is a quarterly DCF model, which reflects quarterly dividend payments and annual, if any,
9 dividend changes, necessary to properly estimate the cost of capital?

10 A. Yes. The DCF model used should properly reflect the known circumstances, that is, the
11 time value of different cash flows; otherwise, the resulting cost of capital estimate could be
12 distorted.

13 Q. Have you used a quarterly DCF model to determine the required rate of return for the firms
14 in your analysis and, if so, why?

15 A. Yes, I have performed a cost of equity analysis using the quarterly DCF model discussed on
16 Schedule 4 and I have relied on this model in developing my estimate of the Company's
17 cost of common equity. Because all of the companies in my comparable group pay
18 dividends on a quarterly basis, I have employed a quarterly DCF model in my analysis.

19 Since the quarterly DCF model correctly recognizes the timing of these dividend/cash flow
20 payments and their value to investors it is the appropriate model by which to compute the
21 cost of equity for a utility that pays dividends quarterly. Schedule 4 also provides a
22 thorough discussion of the principles that support the use of a quarterly DCF model.

23 **C. DCF Inputs**

24 Q. What are the inputs to the DCF model that you used?

25 A. The DCF model that I use requires the current market price (P_0), the expected dividend
26 (D_1), and the expected growth rate in dividends (g). As noted above, the current stock price
27 reflects all of the information available to the market and is necessary to properly embody
28 investor expectations; I use a 30-day average stock price, which reflects current conditions,

1 while not being overly dependent on any one day's stock price results. The expected
2 dividend and its expected growth rate are employed by investors and should be reflective of
3 their expectations in valuing a security. Because we are trying to measure a directly
4 unobservable expectation held by investors it is appropriate to employ the most objective
5 set of data that reflect the information and actions taken in the market. Use of these inputs
6 will produce estimates of the cost of equity that are based on investors' rate of return
7 requirements. The stock price and dividend inputs used in my DCF analysis are shown on
8 Exhibit__(KAM-1), Schedule 5, and Exhibit__(KAM-1), Schedule 6, respectively.

9 **1. Expected Dividend Yield**

10 Q. How did you determine the expected dividend yield for the companies in your group?

11 A. For each market-traded utility included in my DCF analysis, I calculated a dividend yield
12 based on a 30-day average price, which was the period from October 5, 2006 to November
13 15, 2006. Exhibit__(KAM-1) Schedule 6 presents the estimated quarterly dividend
14 amount and Exhibit__(KAM-1) Schedule 7 presents the annual dividend yield (calculated
15 using quarterly DCF model) for the comparable companies.¹¹

16 Q. Why did you use a 30-day historical average stock price in your analysis?

17 A. I have determined that an average stock price based on the 30 most recent business days at
18 the time I did my analysis, which reflects stock prices from a six-week period, is suitable
19 for use in my DCF analysis. A six week average stock price provides many of the benefits
20 of the use of a current stock price while not being overly influenced by short-term
21 fluctuations. While averaging stock prices gives equal weight to both the oldest
22 observations and current observations and therefore detracts from the DCF model's ability
23 to reflect the most current expectations, it is important, from a regulatory point of view, to
24 ensure that the DCF calculations are seen as transparent and not tainted by accusations of

¹¹ As will be discussed below I provide two estimates, one based on a comparable group of four firms and one based on five firms.

1 selection bias. The 30-day average stock prices of the companies in my comparable group
2 are shown on Schedule 5.

3 **2. Growth Rate**

4 Q. Please discuss the growth rate used in the DCF model.

5 A. A growth rate that reflects investors' expectations is a required input into the DCF model.
6 As a result, investors' expectations are the key element in any DCF analysis. Although the
7 current market price reflects aggregate investor expectations, no method exists to directly
8 observe and measure the market-consensus expected growth rate for a company. Therefore,
9 I have used two approaches to determine the expected growth rate for the proxy group
10 companies. The first approach relies on the information published in investor surveys. This
11 approach is the best approximation of understanding what investor expectations are since
12 the surveys are aggregations of the investors' views themselves. While survey results do not
13 enable us to see directly into the minds of investors, they do represent widely held
14 expectations. The second approach employs the sustainable growth rate methodology. Here
15 we employ the same rationale as in the estimation of the overall cost of equity in that, we use
16 our group of comparable firms to obtain data to infer the expected growth rate based on the
17 our comparable group.

18 Q. What survey information did you employ?

19 A. I employed the information in *The Value Line Investment Survey*.

20 Q. How did you use information found in *The Value Line Investment Survey* in performing your
21 growth rate analysis?

22 A. Value Line provides data that can be used to estimate the growth rate. Value Line provides
23 data on historical and projected earnings per share, which I use to calculate the five-year
24 Value Line EPS growth rate, as shown on Exhibit____(KAM-1), Schedule 8. To estimate
25 the long-term growth of the utility, projections of future EPS are appropriate. Financial
26 analysts, such as Value Line (an independent financial information service), exert
27 considerable influence over the many investors who do not possess the resources to make

1 their own forecasts. The accuracy of these forecasts, in the sense of whether they turn out
 2 to be correct, is not the issue as long as they reflect widely held investor expectations.
 3 Schedule 8 summarizes the Value Line EPS growth rate that I calculated.

4 Q. Could you explain what is meant by a sustainable “BR + SV” growth rate?

5 A. Yes. Growth can be defined as:

$$g = B * R + S * V \quad (4)$$

Where:

B = expected retention ratio

R = expected return on equity

S = percent new equity expected

V = 1 - book to market ratio

6 Investors expect growth in the return to a stock to occur through both retained earnings and
 7 the sale of new stock at a premium to book value. Thus, it is important that the $S * V$ term
 8 not be ignored, otherwise the resulting formula will not accurately represent investor
 9 expectations. The results of the sustainable growth method are presented on Schedule 8.

10 Q. What are the appropriate inputs to use in determining the internal growth rate of your gas
 11 utility group?

12 A. Investors realize that, over time, a variety of factors will affect a utility’s expected earned
 13 return and expected retention ratio. Because investors’ long-run expectations of the earned
 14 return on common equity and expected retention ratio are not directly observable, estimates
 15 must be determined based upon an analysis of both long-term and short-term trends.

16 The September 15, 2006 edition of *The Value Line Investment Survey* can be used to
 17 estimate both the retention ratio (b) and the expected return on equity (r) for the 2009 to
 18 2011 period. The product of these numbers yields an internal growth rate for the firms used
 19 in this DCF analysis. Value Line projects a “Percent All Dividends to Net Profits” ratio for

1 the 2009 to 2011 period. One minus this ratio is equal to the retention ratio used as “b” in
2 the “br” calculation. The other necessary input—“r”—is presented by Value Line’s as the
3 “Percent Earned Common Equity.” Exhibits____(KAM-1), Schedule 9 and
4 Exhibit____(KAM-1), Schedule 10 present the inputs and calculations used in my BR + SV
5 analysis. Schedule 8 presents the results of that analysis for the proxy group.

6 **3. Selling and Issuance Costs**

7 Q. Should utilities be allowed the opportunity to recover reasonable costs associated with
8 issuing equity capital?

9 A. Yes. Utilities should be allowed the opportunity to recover from ratepayers the reasonable
10 costs of providing service including the reasonable costs of raising equity capital.
11 Reasonable issuance costs, similar to other allowable expenses, should be borne by
12 ratepayers.

13 Q. Should an increment be added to the required return on common equity of the company due
14 to issuance expenses?

15 A. Yes. Utilities should be allowed the opportunity to recover the reasonable costs of
16 providing service, including the reasonable costs of raising equity capital. If a utility
17 requires equity capital, it can obtain it from either its parent, from minority shareholders (if
18 any), or from an initial public offering. To accurately estimate the cost of a utility’s equity
19 capital, it is necessary to make an issuance expense adjustment to account for the difference
20 between the cost of the common equity to investors and the proceeds to the utility. I
21 understand that public common equity issuances today would occur at the Xcel Energy Inc.
22 (parent) level. There is, none-the-less, an economic cost associated with these issuance
23 costs that should be borne by ratepayers. Further, the equity in the company is a result of
24 prior public offerings made when the former Northern States Power Company (Xcel
25 Energy’s predecessor) was publicly traded.

26 Q. How do you make your selling and issuance expense adjustment?

1 A. It is proper to include an issuance expense return adjustment for the entire equity
2 component of the capital structure.¹² Therefore, I use the conventional form of the issuance
3 expense adjustment:¹³

$$4 \quad r = \frac{D_1}{P_0 * (1 - f)} + g \quad (5)$$

5 Where

6 r = required return adjusted for issuance expenses

7 f = flotation cost percentage

8 For the purpose of choosing an appropriate value for f , the flotation cost percentage, I refer
9 to a publication by Victor Borun and Susan Malley as well as information specific to the
10 public equity issuances relating directly to the Company.¹⁴ Borun and Malley conclude that
11 total flotation costs for electric utilities are about 5.5 percent. My calculation of the average
12 expense the Company has actually incurred is 5.11 percent as found on Exhibit__(KAM-
13 1), Schedule 11.

14 Q. What increment for issuance expenses should be used here?

15 A. As shown on Schedule 11, I support the use of a 5.31 percent increment for selling and
16 issuance expenses. To accurately estimate the cost of equity capital, it is necessary to make
17 an issuance expense adjustment to account for the difference between the price to investors
18 and the proceeds to the Company.

¹² Support for using total common equity appears in: Eugene F. Brigham, *et al.*, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, (May 2, 1985), 28-36.

¹³ This formula appears in Roger A. Morin, *Utilities' Cost of Capital*, (Arlington Virginia: Public Utilities Reports, Inc., 1984), 106; and Eugene F. Brigham, *et al.*, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, (May 2, 1985), 28-36.

¹⁴ Victor M. Borun and Susan L. Malley "Total Flotation Costs for Electric Company Equity Issues," *Public Utilities Fortnightly*, (February 20, 1986), pp. 33-39

1 **D. Summary of Results of DCF Analysis**

2 Q. Based on your DCF analysis, what is the cost of equity of your natural gas utility
3 comparable group?

4 A. As shown on Schedule 7, the DCF cost of equity for my comparable group without Cascade
5 is 10.33 percent. The DCF cost of equity capital for the comparable group including
6 Cascade is 10.99 percent.

7 **E. CAPM Analysis**

8 Q. How does modern portfolio theory factor into the analysis of the cost of equity?

9 A. Modern portfolio theory and the CAPM approach evaluate assets based on their twin
10 characteristics of risk and return. Moreover, these approaches evaluate assets in terms of
11 their effects on the risk and returns of an investors' entire portfolio. The CAPM approach
12 illustrates this relationship in the security market line.

13 Q. Please describe modern portfolio theory.

14 A. Modern portfolio theory recognizes that investors hold securities in a portfolio.¹⁵ Portfolio
15 theory begins by recognizing that:

16 1) There is a tradeoff between risk and return and a rational, risk-averse investor will
17 search for assets that maximize return while minimizing risk; these assets are on the
18 "efficient frontier" shown in panel 1 of Figure 1;

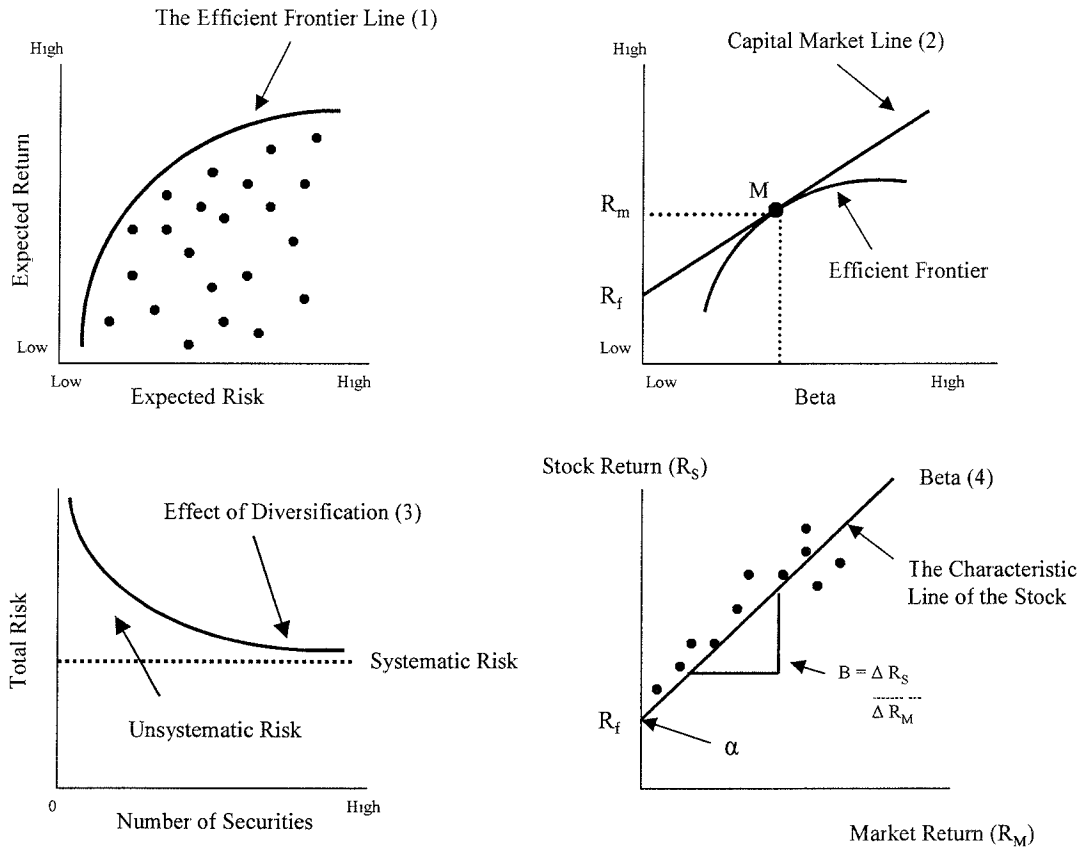
19 2) If you make the simplifying assumptions that there are two types of assets to choose
20 from, a "risky" asset and a "risk-less" or risk-free asset, then the line drawn from the
21 risk-free rate to the efficient frontier, called the "capital market line" represents the
22 set of efficient choices for the investor, shown in panel 2 of figure 1. The investor

¹⁵ In 1990, three of the originators of modern portfolio theory, Harry M. Markowitz, Merton H. Miller, and William F. Sharpe, shared the Nobel prize in Economics for "their pioneering work in the theory of financial economics." See: <http://nobelprize.org/economics/laureates/1990/index.html> (downloaded December 5, 2006).

- 1 can choose the weightings between the risk-free rate and the risky asset, depending
2 on their risk preferences;
- 3 3) Portfolio theory argues that when an investor adds assets to their portfolio that are
4 not highly correlated with the existing assets in their portfolio, this diversification
5 reduces risk without reducing expected return, shown in panel 3 of figure 1; thus,
6 for the investor in a diversified portfolio, only those risks that cannot be diversified
7 away are relevant; and
- 8 4) CAPM builds on each of these concepts, with the return to the investor equal to the
9 risk-free rate and a risk premium that reflects the market's estimate of the cost of
10 bearing additional risk and a measure of the specific risk (beta) that a specific asset
11 has in relationship to the total portfolio's systematic risk that investor cannot avoid
12 through further diversification; this beta is depicted in panel 4 of **Figure 1**.

1

Figure 1: Modern Portfolio Theory



1 Q. Please describe the CAPM analysis used to determine the cost of equity capital.

2 A. The CAPM is based on the theory that the expected rate of return for a given security is
3 equal to the risk-free rate of return plus a risk premium associated with that security. The
4 CAPM is consistent with the belief that investors are risk averse. If an investor has an
5 opportunity to purchase one of two securities with equal expected return, he or she will
6 purchase the security with less risk. Conversely, if an investor has an opportunity to
7 purchase one of two securities with equal risk, he or she will purchase the security with the
8 higher expected return.

9 The Capital Asset Pricing Model can be expressed mathematically as follows:

10
$$R_j = R_f + \beta_j (R_m - R_f) \quad (6)$$

11 Where:

12 R_j ≡ the required rate of return for stock j;

13 R_f ≡ the risk-free rate;

14 R_m ≡ the expected return for the market portfolio; and,

15 β_j ≡ the measure of risk for stock j *vis-à-vis* the market.

16 Q. What risk-free rate did you use?

17 A. In the CAPM model, investors can invest in either a risky asset or a risk-less asset and
18 weights these assets in a portfolio based on risk preferences. The risk-free rate fluctuates
19 with conditions in the capital markets as well as inflation expectations. The risk-free rate
20 represents the interest rate (*i e*, return) required by investors to defer current consumption
21 for future consumption.

22 I use the 4.73 percent yield on 30-year Treasury Bonds as of November 17, 2006 as the risk
23 free rate.

24 Based on the November 17, 2006 *Value Line Selection & Opinion*, the bond equivalent
25 yield on 30-year Treasury Bills stood at 4.73 percent. This observation coincides with the

1 other data inputs used in my DCF and CAPM analyses. I used this risk-free rate directly in
2 my CAPM model as shown on Exhibit____(KAM-1), Schedule 12.

3 Q. Why have you chosen the yield for U.S. treasury bonds as the measure of the risk-free rate
4 in your CAPM analysis?

5 A. The yields of fixed income securities include premiums for default risk and interest rate
6 risk. Default risk relates to the possibility that the debtor will default on principal or
7 interest payments. U.S. Treasury securities have virtually no default risk because of the
8 Federal government's fiscal and monetary authority.

9 Common equity return requirements incorporate the expected inflation rates that are
10 expected to prevail over the long run and thus U.S. Treasury Bonds more closely matches
11 the life-span of common equity investments. I have therefore used a risk-free rates (R_f)
12 that is based on the yield of long-term U.S. Treasury Bonds, which incorporates inflation
13 expectations over a long investment horizon.

14 Q. How did you determine the return on the market portfolio?

15 A. A return on the market was estimated by conducting a DCF analysis for the firms that
16 comprise the Standard and Poor's Stock Index (i.e., "the S&P 500"). A forward-looking
17 market risk premium can be calculated by subtracting the risk-free rate from the estimated
18 13.15 percent "top-down" cost of equity capital of the S&P 500. Reuters¹⁶ provides an
19 11.03 percent estimate of the "top-down" estimated five-year earnings growth rate of the
20 S&P 500, and S&P¹⁷ provides a 1.81 percent estimate of the current dividend yield of the
21 S&P 500. Combining these inputs using the standard DCF model provides a forward-
22 looking, top-down DCF cost of common equity for the S&P 500 of 13.15 percent, as shown
23 on Exhibit____(KAM-1), Schedule 13. This represents the best available estimate of the
24 expected return on the market consistent with the CAPM theory.

¹⁶ "Expected Annual Growth Rates" for the S&P 500 is available from Reuters as published through Vanguard.

1 Q. What firm-specific estimate of risk did you use in your CAPM analysis?

2 A. In the CAPM analysis, the market risk premium (denoted in equation (6) as “ $(R_m - R_f)$ ”)
3 must be adjusted by a firm-specific measure of risk to derive a firm-specific risk premium.
4 The beta coefficient (beta) is widely recognized by the financial community as a firm-
5 specific measure of risk. Beta measures the sensitivity of an individual stock’s return to
6 fluctuations in the market as a whole. For example, a beta of 0.80 indicates that a stock’s
7 return tends to rise or fall at 80 percent of the level of the market’s movements. That is, for
8 a given level of market volatility, a stock with a beta of 0.80 will be less risky than a stock
9 with a beta of 1.0.

10 The beta for a security is estimated using the following ordinary least-squares technique:

11
$$R_{j,t} = \alpha + \beta(R_{m,t}) + \varepsilon_t \quad (7)$$

12 Where:

13 $R_{j,t} \equiv$ the return on security j in period t;

14 $\alpha \equiv$ the intercept term;

15 $\beta \equiv$ the measure of risk for stock j;

16 $R_{m,t} \equiv$ the return on the market portfolio in period t; and,

17 $\varepsilon_t \equiv$ the error term in period t.

18 Equation (7) represents a mathematical relationship between earned returns of a particular
19 stock and a market portfolio and identifies a measurement of risk that explains the
20 difference in returns. Beta is that measurement of risk.

(...continued)

¹⁷ “S&P 500 Statistics,” available at
http://www2.standardandpoors.com/NASApp/cs/ContentServer?pagename=sp/Page/IndicesIndexPg&l=EN&b=4&f=1&s=6&ig=48&i=56&r=1&xcd=500&fd=IndicesMonthEnd_500 (downloaded November 16, 2006)

1 The risk measured by beta is known as systematic risk and represents that portion of total
2 risk that cannot be eliminated by holding a well-diversified portfolio. The CAPM and
3 modern portfolio theory submit that, in the context of a well-diversified portfolio, investors
4 are not rewarded for risk that can be eliminated through diversification (*i.e.*, non-systematic
5 risk). Therefore, investors price only systematic risk in the market place.

6 I use beta estimates published by Value Line for each firm in my gas utility group. The
7 published beta estimates for each of these firms are included within Exhibit____(KAM-1),
8 Schedule 12.

9 Value Line's beta is derived from a regression analysis between weekly percent changes in
10 the price of a stock and weekly percent changes in the New York Stock Exchange
11 Composite Index over a period of five years. That is, Value Line utilizes 260 observations
12 of weekly stock price and index data.

13 Q. Using the CAPM, what is your estimate of the cost of common equity?

14 A. My CAPM analysis indicates that the cost of common equity for the proxy group without
15 Cascade is 12.31 percent and with Cascade is 12.23 percent. My calculations are shown on
16 Schedule 12.

17 III. COST OF EQUITY RECOMMENDATION

18 Q. What is the cost of equity for the Company?

19 A. Based on my entire analysis, I believe that the Company's cost of equity is within the range
20 of 10.33 percent to 12.31 percent. In my professional opinion, a reasonable and fair cost of
21 equity for the Company is 11.32 percent, which is the mid-point of a range established
22 using a four-company comparable group as shown on Exhibit____(KAM-1), Schedule 2.
23 My conclusion is supported by the results of the analysis using the comparable group that
24 includes Cascade as shown on Exhibit____(KAM-1), Schedule 2. The data relating to
25 Cascade should be given consideration, since the concerns that typically apply to data
26 relating to a company involved in a merger do not appear to apply to Cascade, as I have
27 shown earlier in my testimony.

1 Q. Does this conclude your pre-filed direct testimony?

2 A. Yes.


3

1
2 STATE OF NORTH DAKOTA
3 BEFORE THE
4 PUBLIC SERVICE COMMISSION
5
6

7 In the Matter of the Application of Northern)
8 States Power Company, a Minnesota corporation) **Notice of Change in Rates**
9 and wholly owned Subsidiary of Xcel Energy Inc.)
10 for Authority to Increase Rates For Natural Gas) Case No. PU-06-____
11 Service in North Dakota)

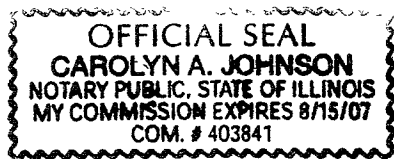
12
13
14
15 **AFFIDAVIT OF**
16 **Karl A. McDermott**
17

18
19 I, the undersigned, being duly sworn, depose and say that the foregoing is
20 the Direct Testimony of the undersigned, and that such Direct Testimony and the
21 exhibits or schedules sponsored by me to the best of my knowledge, information
22 and belief, are true, correct, accurate and complete, and I hereby adopt said
23 testimony as if given by me in formal hearing, under oath.
24

25
26 
27 _____
28 Karl A. McDermott
29
30
31

32 Subscribed and sworn to before me, this 12 day of December, 2006.
33

34
35 
36 _____
37 Notary Public
38



Karl A. McDermott

Vice President

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KARL A. MCDERMOTT

VICE PRESIDENT

Dr. McDermott is a Vice President specializing in public utility regulation. At NERA Dr. McDermott has directed and participated in numerous projects in both the energy and telecommunications areas. His main focus has been the development of performance-based regulation mechanisms and advising clients on strategic regulatory options. Recent projects include evaluating and developing performance-based regulation plans and strategic regulatory options for Commonwealth Edison Company, Detroit Edison Company, Michigan Consolidated Gas, Wisconsin Electric Power Company, Xcel Energy, Otter Tail Power, Peoples Energy, Louisville Gas and Electric, and PowerGen along with MidAmerican Energy. In addition, Dr. McDermott advises clients on competitive electric and gas markets including regulatory policy, generation location decisions, unbundling, tariff design, and corporate reorganization. Recent projects include an examination of essential facilities debate for the Edison Electric Institute, tariff design and competitive electric generation sitting for Southern California Gas Company and Southern Energy, and a review of unbundling of metering and billing for Commonwealth Edison Company. He has testified before numerous state regulatory commissions and legislatures, as well as before the FCC and FERC. Dr. McDermott lectures extensively on regulatory reform and restructuring and currently serves as an instructor for National Association of Regulatory Utility Commissioners summer seminars and advanced seminars.

Prior to joining NERA, Dr. McDermott served as Commissioner on the Illinois Commerce Commission during the negotiation of the Illinois restructuring law. He has also assisted the country of Poland since 1994 with their efforts to privatize and restructure their electric supply industry. As a Commissioner, Dr. McDermott also lectured extensively in Eastern Europe and South America on regulatory reform and restructuring.

During the six years that he served as Commissioner, Dr. McDermott evaluated alternative regulation proposals and the economic and social impacts of a number of new policies presented to the Commission. As a Commissioner, Dr. McDermott initiated the Commission's investigation into the alternative restructuring options and has made a number of presentations on restructuring issues.

Dr. McDermott received his Ph.D. in Economics from the University of Illinois at Urbana-Champaign, his M.A. in Public Utility Economics from the University of Wyoming, and his B.A. in Economics from Indiana University of Pennsylvania.

Education

University of Illinois, Urbana-Champaign

Ph.D., Economics, 1990

Major Fields: Monetary theory and Policy, Macroeconomic Theory, and History of Economic Thought

University of Wyoming

M.A., Public Utility Economics, 1978

Major Fields: Public Utility Economics and Industrial Organization Theory

Indiana University of Pennsylvania

B.A., Economics, 1976

Professional Experience

1999- NERA Economic Consulting

Vice President

Directs projects in the energy and telecommunications fields. Conducts research in the design and review of performance-based regulation mechanisms. Provides strategic regulatory advice to international and domestic clients. Advises on competitive issues facing regulated firms, including regulatory policy, unbundling, corporate structure, and tariff design.

1998-1999 McDermott Associates

President

Directed projects in the energy and telecommunications fields focusing on performance-base regulation, electric industry restructuring, and competition policy issues.

1992-1998 Illinois Commerce Commission

Commissioner

Domestic: Served as Chairman of both the Telecommunications Policy Committee and Electricity Policy Committee. Served on the National Association of Regulatory Utility Commissioners (NARUC) Energy Resources and Environment Committee as the Chairman of its environmental subcommittee. Reviewed and voted on Illinois Bell Price-Cap plan, Peoples Gas PBR and MidAmerican Electric PBR. While a commissioner, made over one-hundred presentations and speeches on telecommunications, electricity, and natural gas industry topics. Also served as NARUC representative on the President's Global Climate Change Task Force, the Federal Energy Regulatory Commission's Pipeline Competition Task Force, the National Coal Research council, and as a

member of the Harvard Electric Policy Group.

International: In addition to regular Commission duties, served as part of the United States Energy Association and USAID educational effort in Eastern Europe. Lectured in Argentina, the Czech Republic, Latvia, Poland, Romania, Russia, and Slovakia and participated in two joint USEA/USAID and World Bank seminars in Vienna providing advanced regulatory training. While a commissioner, hosted visits with the above-listed countries, as well as Bulgaria, Lithuania, and Estonia.

Additional Professional Experience

- 2001- **Michigan State University, Institute for Public Utilities**
Faculty
Invited lecturer at Regulatory Studies Program (“Camp NARUC”) held in East Lansing, Michigan. Lecture topics include performance-based regulation, rate-of-return regulation, infrastructure regulation for developing countries, and gas wholesale markets.
- 1985-1998 **Center for Regulatory Studies, Inc.**
Chairman of the Board
- 1985-1992 **President**
As a cofounder, involved in all aspects of operations, including fundraising, organization, and program development. Focused on the development of statewide energy planning options for the State of Illinois, the introduction of competition into the natural gas market, environmental issues in Illinois, and competition in the Illinois telecommunications market. Conducted research on the use of competitive bidding and avoided-cost pricing mechanisms to acquire electricity supplies, the role of demand-side management in electricity supply planning, and the use of incentive mechanisms and the role of incentive regulation in our current regulatory environment.
- 1988-1992 **Argonne National Laboratory**
Research Scientist
Served as an economic advisor to the office of Fossil Energy at DOE. Helped investigate possible ways to promote development of innovative emission control technologies and Clean Coal Technologies in the electric utility industry, as part of the Presidential Task Force on Regulatory Relief. Assignments also involved the writing of a chapter in the State of Science and Technology Report No. 25 of the National Acid Precipitation Assessment Program (NAPAP) concerning the use of tradable emission permits to control acid rain. In addition, worked on incentive mechanisms to promote clean coal technology and the trading of greenhouse gas emissions. Also performed research on the nature of individual's risk perception regarding nuclear waste deposits on behalf of the office of Radioactive Civilian Waste Management at the Department of Energy.

- 1989-2006 **NARUC Introductory Regulatory Training Program**
Instructed new public utility commission employees from various state commissions on the basic economic issues confronting regulators.
- 1986-1992 **Illinois State University, Department of Economics**
Lecturer in Economics
Taught both graduate and undergraduate public utility courses, Money and Banking, as well as introductory courses.
- 1984-1991 **Parkland Community College, Champaign, Illinois**
Instructor in Economics
Taught both Principles of Economics I and II.
- 1984-1986 **University of Illinois, Urbana-Champaign**
Teaching Assistant
Taught both Principles of Economics and Introduction to Econometrics. Served as supervisory assistant in charge of coordinating Economics 101 assistants for Professor Fred Gotthiel.
- 1983-1985 **Illinois Legislature, Select Joint Subcommittee on Regulatory Reform**
Consultant
Investigated the effects of the AT&T divestiture and FCC decisions upon Illinois telephone utilities and assisted in identifying issues that require legislative action. Presented issue reports to the telecommunications subcommittee and served on the local exchange subgroup in developing recommendations for a new Illinois Public Utilities Act.
- 1980-1982 **Department of Energy and Natural Resources, Governor's Sunset Task Force on Utility Regulatory Reform**
Consultant
Delivered written and oral reports on the issues of power plant certification, monitoring of construction costs, and allocation of power plant cancellation costs.
- 1980-1983 **Illinois Commerce Commission, Policy Analysis and Research Division**
Economic Analyst III
Conducted research investigating the development and use of incentive mechanisms in utility regulation. Prepared and presented testimony on the use of incentive mechanisms in power plant construction. Conducted research and assisted in developing testimony on the cost of service for electric generation to meet PURPA requirements. Assisted in the development of proposals for PURPA innovative rates projects on productivity and time-of-use pricing; cost-benefit analysis. Assisted in the management of consultants conducting the TOD cost-benefit study. Prepared and presented testimony on the time-of-day pricing standards to meet the PURPA requirements. Prepared and presented testimony regarding the use of q-ratios in determining rates-of-return for Illinois Bell Telephone Company and testimony regarding appropriate cost and pricing

methodology and philosophy for Illinois Bell Telephone Company. Assisted in the investigation of capacity expansion, lifeline rates, efficiency measurement, and impact of deregulation in electric generation, water rate design, and investigated the impact of investment tax credit changes on utilities.

- Ohio State University, National Regulatory Research Institute**
1978-1979 Senior Research Associate
Conducted research in the areas of telecommunication licensee contract fees and cost of service, the effects of budget billing plans on utilities and consumers, as well as methods of monitoring fuel adjustment clauses. Assisted in research regarding marginal and average cost pricing, time-of-use pricing, power plant productivity, and the examination of cost and price differences of Ohio municipal gas rates. Assisted in the management of consultant subcontractors, as well as supervising the presentation of cost and load research seminars.
- Ohio State University, Department of Economics**
Fall 1979 Lecturer in Economics
Taught Macroeconomic Principles.
- Action Computing, Laramie, Wyoming**
1977-1978 Cost Analyst
Developed cost data for competitive pricing of bids for the provision of computer services provided by Action Computing.
- University of Wyoming, Laramie**
1976-1977 Graduate Research Assistant
Assisted professors in conducting research and teaching of Principles of Economics.

Honors and Professional Activities

- Alpha Lambda Delta Outstanding Freshman Teacher Award, University of Illinois, 1986
- Thrift Prize, University of Illinois, for paper entitled "The Allocation of Savings: An Investigation of Portfolio Composition of Chicago Households," 1983
- President Elect and President, Illinois Economic Association, 1988-1990
- Member, Alpha Lambda Delta Honorary Society
- Member, American Economic Association
- Member, Transportation Public Utilities Group of American Economic Association

Member, Illinois Economic Association

Representative Projects

Evaluation and design of performance based regulation for clients, including Detroit Edison Company (bundled electricity service), Michigan Consolidated Gas (gas distribution), NICOR Gas (gas procurement), Otter Tail Power (bundled electricity service), and Xcel Energy (bundled electricity service), among others.

Evaluation of damages from coal-fired power plant explosion for Kansas City Power and Light (Hawthorn 5 unit).

Evaluation of prudence of certain distribution investments and O&M costs for Commonwealth Edison Company.

Evaluation of POLR responsibility in state of Illinois for Commonwealth Edison.

Evaluation of market structure options and development of tariff model for Macedonian electric sector.

Evaluation of future options for the reform of the Albanian electric sector.

Evaluation of electric industry structure and proper public policy toward utilities building power plants.

Estimation of potential energy efficiency gains for Wisconsin Electric Power Company (WEPCO) and Wisconsin Public Service Corporation in support of power plant construction.

Evaluation of tariff options for Otter Tail Power Company.

Evaluation of options for unbundled distribution rates and policies toward small-use customer choice for Illinois Power.

Review of gas rate design for peaking service and evaluated electric generation site decisions in California for Southern California Gas Company.

Publications

“The Anatomy of Institutional and Organizational Failure,” in *Obtaining the Best from Regulation and Competition*, M. Crew and M. Spiegel (eds.), Kluwer Academic Publishers, London, UK, 2005, pp. 65-92 (with Carl Peterson).

“Performance-Based-Rates Upward Trend to Continue,” in *Natural Gas and Electricity*, 20(6), 2004 (with Carl Peterson).

“Is There a Rational Path to Salvaging Competition?” *The Electricity Journal*, 15(2), 2002, pp. 15-30 (with Carl Peterson).

“Further State Electric Deregulation can be Guided by Gas Experience,” in *Natural Gas and Electric Power Industries Analysis*, R.E. Willett (ed.), Financial Communications Company, Houston, TX, 2002, pp. 343-372 (with Carl Peterson).

“The Essential Role of Earnings Sharing in the Design of Successful Performance-base Regulation Programs,” in *Electricity Pricing in Transition*, A. Faruqui and K. Eakin (eds.), Kluwer Academic Publishers, London, UK, 2002, pp. 315-328 (with Carl Peterson).

“Critical Issues in Consumer States Include Unbundling and Performance-based Regulation,” in *Natural Gas Industry Analysis*, R.E. Willett (ed.), Financial Communications Company, Houston, 2000, 321-343.

“Are Residential Local Exchange Rates Too Low? Drivers to Competition in the Local Exchange Market and the Impact of Inefficient Prices,” in *Expanding Competition in Regulated Industries*, M. Crew (ed.), Kluwer Academic Publishers, Boston/Dordrecht/London, 2000, 149-168 (with A. Ros).

Essential Facilities, Economic Efficiency, and a Mandate to Share: A Policy Premier, Edison Electric Institute, January 2000 (with K. Gordon, W. Taylor, and A. Ros).

“Pipeline Regulation Must go to One Extreme or Another,” in *Natural Gas*, 15(9), April, 1999.

“Is There a Rational Path to Implementing Competition?” in *The Electricity Journal*, 9(1), Jan-Feb 1996.

“Changing Regulatory Incentives,” in *Reinventing Electric Utility Regulation*, G. Enholm and J. Robert Malko (Eds.), Public Utility Reports, Inc. Vienna, VA 1995.

“The Evolution of the “Investment Systems:” Keynes’ Theory of Employment and Money Revisited,” in *Review of Social Economy*, 51(1), Spring 1993.

Discussant. “The Urban Ozone Abatement Problem,” in *Cost Effective Control of Urban Smog*. R. Kosobud, W. Testa, and D. Hansan (Eds.) Federal Reserve Bank of Chicago. November 1993.

“Strategic Use of Incentive Mechanisms as a Regulatory Policy Tool,” in *The Electricity Journal*. 5(10), December 1992.

“Electric Utilities: Control Cost Reducing Methods,” Chapter 7 in *Technologies and Other Measures for Controlling Emissions: Performance, Costs and Applicability*, David South (ed.). National Acid Precipitation Assessment Program, State-of-Science/Technology Report, 25 January 1990.

“The Quantity Theory of Money of J. M. Keynes: From the Indian Currency to the General Theory” in *Perspectives on the History of Economics Thought*. D., Walker (ed.), Edward Edgar Publishing Co., Brookfield, VT, 1989 (with Christopher Marme).

Computer Assisted Regulatory Analysis and Its Potential Application to the Colorado Public Utilities Commission. The National Regulatory Research Institute, 1979 (with M. S. Gerber).

Towards an Analysis of Telephone License Contracts and Measured Rates. The National Regulatory Research Institute, 1979 (with A. G. Buckalew, and D. Z. Czamanski).

Budget Billing Plans for Electric and Gas Utilities: An Analysis and Some Recommendations for Change. The National Regulatory Research Institute, 1979 (with J-M Guldman and C. Odle).

Conference Papers

Prudence: The Regulators Strike Back: A Prequel to the Revenge of the Regulator, presented at Center for Research in Regulated Industries, Rutgers University, conference held in San Diego, CA, June 2005.

Mergers and Acquisitions in the Electric Industry: A Review of State Regulatory Policies, presented at Center for Research in Regulated Industries, Rutgers University, conference held in Sky Top, PA, May 2005 (with Carl Peterson).

The Anatomy of Institutional and Organizational Failure: Economic Reform and the Search for Institutional Equilibrium in Regulated Network Industries, preliminary draft presented at Research Seminar on Public Utilities, Center for Research in Regulated Industries, Rutgers University, October 2003 (with Carl Peterson).

The Efficiency of the Inefficient Firm Standard in Setting Network Access Charges, prepared for 20th Annual Advanced Workshop in Regulation and Competition, Rutgers University, May 25, 2001 (with Carl Peterson).

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5/18/06

**Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility
Cost of Common Equity**

Four Company Comparable Group:

Low End of Range:	DCF Average	10.33 %
High End of Range:	CAPM	12.31
Recommended Cost of Equity		11.32 %

Comparable Group and Cascade:

Low End of Range:	DCF Average	10.99 %
High End of Range:	CAPM	12.23
Recommended Cost of Equity		11.61 %

Value Line Gas LDCs	Exclude the following companies using the specified criteria:				Gas LDC Comparable Group
	Market Cap <\$10.0 Billion	Eliminated or Cut Dividends	Operating Revenues from Regulated Entities >80%	Company Involved in Merger	
Cascade Natural Gas Piedmont Natural Gas Northwest Nat. Gas Nicor Southwest Gas KeySpan Corp. South Jersey Inds Laclede Group Peoples Energy WGL Holdings Inc Energen Corp Atmos Energy New Jersey Resources UGI Corp AGL Resources NUI Corp. SEMCO Energy Southern Union	None	NUI Corp. SEMCO Energy Southern Union	South Jersey Inds Laclede Group Peoples Energy WGL Holdings Inc Energen Corp Atmos Energy New Jersey Resources UGI Corp	AGL Resources KeySpan Corp. Cascade Natural Gas ¹	Piedmont Natural Gas Northwest Nat. Gas Nicor Southwest Gas Cascade Natural Gas ²

[1] The Cascade merger was recently announced on July 9, 2006.

[2] As explained in my testimony and exhibits, DCF and CAPM estimates that include Cascade along with the four companies in my peer group are presented.

**Northern States Power Company d/b/a Xcel Energy
 State of North Dakota – Gas Utility Operation**

A. The Annual Discounted Cash Flow Model

The DCF model implies that the value of an asset is the sum of the future benefits generated by the asset, discounted by the investor's required rate of return. Specifically, the market value of a common stock is equal to the present value of the expected stream of future dividends.

In its general form, the DCF model can be stated as follows:

$$(1) P_0 = \frac{D_1}{(1+k_e)} + \frac{D_2}{(1+k_e)^2} + \frac{D_3}{(1+k_e)^3} + \dots + \frac{D_n}{(1+k_e)^n}$$

where: P_0 = the current market price;
 D_t = the expected dividend at the end of period t (where t = 1 to n);
 k_e = the cost of common equity; and,
 n = infinity.

If dividends are anticipated to grow at the rate of g each period and $g < k_e$, equation (1) can be rewritten as:

$$(2) P_0 = \frac{D_0(1+g)}{(1+k_e)} + \frac{D_0(1+g)^2}{(1+k_e)^2} + \frac{D_0(1+g)^3}{(1+k_e)^3} + \dots + \frac{D_0(1+g)^n}{(1+k_e)^n}$$

where: g = the expected growth rate.

Formula 2 can be reduced to:

$$(3) P_0 = \frac{D_1}{k_e - g}$$

Solving Equation (3) for k_e results in the following:

$$(4) k_e = \frac{D_1}{P_0} + g$$

Equation (4) can be restated as:

$$(5) \quad k_e = \frac{D_0(1+g)}{P_0} + g$$

where: D_0 = the most recent dividend.

B. The Quarterly Discounted Cash Flow Model

As shown earlier, if we assume that dividends are anticipated to grow at the rate of g each period and $g < k_e$, then we can rewrite the general DCF equation as:

$$(6) \quad P_0 = \frac{D_0(1+g)}{(1+k_e)} + \frac{D_0(1+g)^2}{(1+k_e)^2} + \frac{D_0(1+g)^3}{(1+k_e)^3} + \dots + \frac{D_0(1+g)^n}{(1+k_e)^n}$$

where:

P_0	=	the current market price;
D_0	=	the current dividend;
k_e	=	the cost of common equity;
g	=	the expected growth rate; and,
n	=	infinity.

If we assume that $(D_{t-1,Q1})$, $(D_{t-1,Q2})$, $(D_{t-1,Q3})$, and $(D_{t-1,Q4})$ represent the quarterly dividend payments at the end of the quarters in the year preceding the date of analysis (t_0) and that dividends are expected to grow as at annual rate of g , then formula 1 can be rewritten as:

$$(7) \quad P_0 = \frac{(D_{t-1,Q1})(1+g)}{(1+k)^{25}} + \frac{(D_{t-1,Q2})(1+g)}{(1+k)^{50}} + \frac{(D_{t-1,Q3})(1+g)}{(1+k)^{75}} + \frac{(D_{t-1,Q4})(1+g)}{(1+k)} + \sum_{t=1}^{\infty} \sum_{Q=1}^4 \frac{(D_{t,Q})(1+g)}{(1+k)^{t+25Q}}$$

Equation (7) can be simplified to:

$$(8) \quad k = \frac{(D_{t,Q1})(1+k)^{75} + (D_{t,Q2})(1+k)^{50} + (D_{t,Q3})(1+k)^{25} + (D_{t,Q4})}{P_0} + g.$$

In equation 3, k must be solved for through an iterative process. Upon solving k , equation 3 provides the return investors require for investing in a stock that pays dividends quarterly.

C. Use of a Quarterly DCF Model

The discounted cash flow ("DCF") model is a present value model that discounts a stream of expected cash flows to determine their cumulative current value. The timing of the expected cash flows is crucial for an accurate assessment of that value. A key assumption of any present value model, including a DCF model, is that each cash flow is reinvested at the discount rate as soon as it is received. If this assumption is violated, the results of any present value analysis will be biased.

An example will demonstrate how the reinvestment assumption is implicit in present value analysis (including a DCF analysis). Assume an investor has the opportunity to receive one dollar at the end of each quarter of a year for one year. Also assume the investor requires a return of 4% per quarter. The price the investor should be willing to pay for those four quarterly cash flows can be determined using the following formula:

$$PV = \sum_{n=1}^4 \frac{CF_n}{(1+k_{eq})^n}$$

where:

PV = the price the investor is willing to pay for the investment;

CF_n = the cash flow received at the end of each quarter n; and

k_{eq} = the investor's quarterly required rate of return.

In the above example, the price the investor is willing to pay for the investment opportunity (i.e., the present value of the cash flows) is equal to the following:

$$\begin{aligned} PV &= \frac{\$1}{1.04} + \frac{\$1}{(1.04)^2} + \frac{\$1}{(1.04)^3} + \frac{\$1}{(1.04)^4} \\ &= \$3.63. \end{aligned}$$

Now assume that rather than investing in the four quarterly cash payments, the investor places \$3.63 in an investment of equivalent risk that pays 4% interest on a quarterly basis. At the end of the year, the value of the investment can be determined using the following formula:

$$FV = PV(1+k_{eq})^n$$

where:

FV = the value of the investment at the end of the nth period.

In the above example, the value of the investment (i.e., the future value) at the end of the fourth quarter is equal to the following:

$$\begin{aligned} \text{FV} &= \$3.63 (1.04)^4 \\ &= \$4.25. \end{aligned}$$

Note that this future value is achieved by compounding (i.e., reinvesting) interest.

The two investments above differ only in the timing of the cash flows. In the former, the investor receives one dollar per quarter for four quarters. In the latter, the investor receives a single payment of \$4.25 at the end of the fourth quarter. Given that the prices (i.e., present values), risk and discount rates are identical for the two investments, an investor should be indifferent between the two. Although the investor receives only \$4 in the former example (versus \$4.25 in the latter example), no inconsistencies exist in the valuation process. The former investment provides the investor with the opportunity to reinvest each cash flow immediately upon receipt, at the discount rate.

The future value of the reinvested cash flow stream is determined using the following formula:

$$\text{FV} = \sum_{n=1}^4 \text{CF}_n (1+k_{\text{eq}})^{4-n}$$

Thus, the future value of the four quarterly, one dollar cash flows, reinvested at the 4% discount rate, is equal to the following:

$$\begin{aligned} \text{FV} &= \$1[(1.04)_3 + (1.04)_2 + (1.04)_1 + (1.04)_0] \\ &= \$4.25. \end{aligned}$$

A DCF analysis determines the present value of a stream of future cash flows, assuming the cash flows are reinvested at the discount rate immediately upon receipt. This example illustrates that the reinvestment assumption is implicit in present value analysis.

The DCF analysis was originally developed as a valuation tool. That is, in its most general formulation (See equation 1), the model is used to determine how much an investor should be willing to pay for an investment. In an efficient market, the observed price of a given stock is equal to the discounted value of an expected dividend stream. The discount rate is the investor-required rate of return.

When performing a cost of common equity analysis, analysts observe a Company's current stock price, dividend payment and the timing of dividend payments. By using the observed stock price and correctly modeling the timing of dividend payments, analysts can rearrange a DCF model to estimate the investor-required rate of return on common equity. This cost of equity is implicit in the observed stock price.

As previously stated, the timing of dividend payments is crucial. A simple example should help to clarify this point. Company A and Company B are perceived by investors to have equivalent risk. In an efficient market, if investors perceive the risk of two companies to be equivalent, they will require the same rate of return for investing in either Company. In this example, investors will require a 10% return to invest in either Company. Both Company A and Company B pay \$10.00 in dividends over a one-year period. Company A pays a \$10.00 dividend at the end of the year, while Company B pays four quarterly dividends of \$2.50. Although both companies pay the same total dividend, the dividend of Company B is worth more because investors have the opportunity to reinvest the quarterly dividend payments for the remainder of the year at their required rate of return. By year-end, Company A's dividend is worth \$10.00 to investors because Company A pays one \$10.00 dividend at the end of the year. Therefore, investors do not have the opportunity to reinvest the quarterly dividend payments throughout the year. The year-end value to investors of Company B's dividend is determined as follows:

- * By reinvesting it, the first quarterly dividend will earn a return over the remaining three quarters of the year. By year-end, the first quarterly dividend will be worth \$2.69 to investors, computed as follows:

$$[\$2.50(1.1)^{75}].$$

- * By reinvesting it, the second quarterly dividend will earn a return over the remaining two quarters of the year. By year-end, the second quarterly dividend will be worth \$2.62 to investors, computed as follows:

$$[\$2.5(1.1)^5].$$

- * By reinvesting it, the third quarterly dividend will earn a return over the remaining one quarter of the year. By year-end, the third quarterly dividend will be worth \$2.56 to investors, computed as follows:

$$[\$2.50(1.1)^{25}].$$

- * The fourth quarterly dividend will be paid at year-end and will not earn any return by year-end. Hence, the fourth quarter dividend's year-end value to investors will remain \$2.50.

- * The total year-end value to investors of these four quarterly dividend payments is the summation of each dividend's end-of-year value or \$10.37.

Although investors perceive the risks of Companies A and B to be equivalent, and both companies pay \$10.00 in dividends over a one year period, investors will pay a higher price for Company B's stock relative to Company A's stock. Investors are willing to pay a higher price for Company B's stock because its dividends are paid quarterly. Company B's four quarterly dividends have a greater year-end value to investors than Company A's single year-end

dividend payment. Using the DCF model (equation 3) and, for the sake of simplicity, assuming the investor-expected growth (g) for both companies is 0%, the prices investors should be willing to pay for these companies' stocks are computed as follows:

$$\begin{aligned} P_o &= D_1/(k-g) \\ P_a &= \$10.00/(0.1 - 0.0) = \$100.00 \\ P_b &= \$10.37/(0.1 - 0.0) = \$103.70 \end{aligned}$$

Where:

P_a = the price of Company A's stock;
 P_b = the price of Company B's stock;
 D_1 = the year-end value of the dividend;
 k = the investor-required rate of return; and
 g = the investor-expected dividend growth rate.

This example demonstrates that investors value stocks based in part upon the timing of dividend payments. In a cost of common equity analysis, the analyst is not attempting to estimate the price of a stock. Rather, an analyst observes the stock price, dividend payment and the timing of dividend payments in any number of financial publications (e.g., The Wall Street Journal) and uses that information to estimate an investor-required rate of return.

In summary, if a Company pays dividends quarterly, its observed stock price (as listed in publications such as The Wall Street Journal) is determined by investors with the understanding that dividends are received and reinvested on a quarterly basis. The quarterly DCF model correctly recognizes the timing of dividend payments and hence their value to investors. Thus the quarterly DCF model will correctly estimate the investor-required rate of return that is implicit in the Company's observed stock price. An annual DCF model will not properly recognize the timing of dividend payments and hence, will understate the investor-required rate of return on equity.

Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility
Comparable Group
30-Day Average Stock Prices

Company	Ticker Symbol	Stock Price Date¹	Last Dividend	30-day average Stock Price¹	30-Day Average Stock Price S&I Adjusted
1 Nicor	GAS	15-Nov-06	0.465	46.05	43.60
2 Northwest Nat. Gas	NWN	15-Nov-06	0.345	40.33	38.19
3 Piedmont Natural Gas	PNY	15-Nov-06	0.240	26.74	25.32
4 Southwest Gas	SWX	15-Nov-06	0.205	35.36	33.48
Cascade Natural Gas	CGC	15-Nov-06	0.240	25.66	24.30

Notes:

[1] Yahoo! Finance Research, <http://finance.yahoo.com>, Closing prices for the 30 business days ending on November 15, 2006.

Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility
Comparable Group
Dividends

Company	Recent Quarterly Dividends Paid Per Share (D ₀)				Growth ¹ Rate, g (Percent)	Expected Quarterly Dividend Growth Rate Per Share (D ₁)			
	Q ₁	Q ₂	Q ₃	Q ₄		Q ₁	Q ₂	Q ₃	Q ₄
	(\$/Share)	(\$/Share)	(\$/Share)	(\$/Share)		(\$/Share)	(\$/Share)	(\$/Share)	(\$/Share)
1 Nicor	0.465	0.465	0.465	0.465	4.05	0.48	0.48	0.48	0.48
2 Northwest Nat. Gas	0.345	0.345	0.345	0.345	5.53	0.36	0.36	0.36	0.36
3 Piedmont Natural Gas	0.230	0.230	0.240	0.240	6.02	0.24	0.24	0.25	0.25
4 Southwest Gas	0.205	0.205	0.205	0.205	10.29	0.23	0.23	0.23	0.23
Cascade Natural Gas	0.240	0.240	0.240	0.240	9.10	0.26	0.26	0.26	0.26

Notes:

[1] Simple average of estimated Value Line EPS growth and B*R+S*V growth.

Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility
Comparable Group
Dividend Yield

Company	Expected Quarterly Dividend Growth Rate Per Share (Q)				S&I Adjusted ROE ¹	Expected Quarterly Dividend Growth Rate Per Share (Q) Multiplied by S&I Adjusted ROE Growth Rate (1+R/100) ²				30-Day Average ² Stock Price	Dividend Yield
	Q ₁	Q ₂	Q ₃	Q ₄		R	Y ₁	Y ₂	Y ₃		
	(\$/Share)	(\$/Share)	(\$/Share)	(\$/Share)	(Percent)					(\$)	(Percent)
1 Nicor	0.48	0.48	0.48	0.48	8.62	0.51	0.50	0.49	0.48	46.05	4.34
2 Northwest Nat. Gas	0.36	0.36	0.36	0.36	9.48	0.39	0.38	0.37	0.36	40.33	3.74
3 Piedmont Natural Gas	0.24	0.24	0.25	0.25	10.10	0.26	0.26	0.26	0.25	26.74	3.86
4 Southwest Gas	0.23	0.23	0.23	0.23	13.12	0.25	0.24	0.23	0.23	35.36	2.68
Cascade Natural Gas	0.26	0.26	0.26	0.26	13.63	0.29	0.28	0.27	0.26	25.66	4.29

Notes:

[1] ROE adjusted by selling and issuance expenses.

[2] Yahoo! Finance Research, <http://finance.yahoo.com>, Closing prices for the 30 days ending on November 15, 2006.

Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility
Comparable Group
DCF Cost of Equity

Company	Dividend ¹ Yield (Percent)	Growth ² Rate, g (Percent)	Unadjusted ³ ROE, k _e Before S&I (Percent)	Change (Percent)	S&I ⁴ Adjusted ROE (Percent)
1 Nicor	4.34	4.05	8.38	0.24	8.62
2 Northwest Nat. Gas	3.74	5.53	9.27	0.21	9.48
3 Piedmont Natural Gas ⁸	3.86	6.02	9.88	0.22	10.10
4 Southwest Gas	2.68	10.29	12.97	0.15	13.12
Average:	3.65	6.47	10.13	% 0.20	% 10.33
Cascade Natural Gas	4.29	9.10	13.39	0.24	13.63
Average Including Cascade:					10.99 %

Notes:

- [1] Dividend Yield = [(Total D₀*(1+Growth Rate))/Stock Price]
- [2] Simple Average of Value Line EPS and BR+SV growth rates.
- [3] Not adjusted for selling and issuance expenses.
- [4] ROE adjusted by selling and issuance expenses.

**Northern States Power Company d/b/a Xcel Energy
 State of North Dakota - Gas Utility
 Comparable Group
 Growth Rate Estimates**

Company	Value Line EPS ¹		Estimated VL Growth ² (Percent)	B*R+S*V Growth (Percent)	Average Growth ³ (Percent)
	2005 (\$)	2009-2011 (\$)			
1 Nicor	2.27	2.80	4.29	3.80	4.05
2 Northwest Nat. Gas	2.11	2.85	6.20	4.87	5.53
3 Piedmont Natural Gas	1.32	1.75	5.80	6.24	6.02
4 Southwest Gas	1.25	2.25	12.47	8.10	10.29
Average:			7.19 %	5.75 %	6.47 %
Cascade Natural Gas	0.82	1.60	14.30	3.90	9.10
Average Including Cascade:			8.61 %	5.38 %	7.00 %

Notes:

[1] *The Value Line Investment Survey*: September 15, 2006 (Issue 3).

[2] $(\text{[2009-2011 EPS Estimate]} / \text{[2005 EPS]}^{0.20} - 1) * 100$

[3] Simple average of Estimated Value Line EPS growth and B*R+S*V growth.

Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility
Comparable Group
Sustainable Growth Method

Company	R	D _e	V _e	V		R _{av}	B ³	B*R ⁴	S*V Average	B*R+S*V ⁵
	Estimated Return on Common Equity ¹ (Percent)	Estimated Dividend Per Share ¹ (\$)	Estimated Book Value Per Share ¹ (\$)	Book Value Per Share 2005 (\$)	Book Value Per Share 2004 (\$)	Return on Average Equity ² (Percent)				
1 Nicor	13.00	2.02	21.60	18.36	16.99	13.50	30.75	4.15	(0.35)	3.80
2 Northwest Nat. Gas	10.50	1.70	25.55	21.28	20.64	10.66	37.59	4.01	0.86	4.87
3 Piedmont Natural	13.00	1.17	12.75	11.53	11.15	13.22	30.57	4.04	2.20	6.24
4 Southwest Gas	9.50	0.82	24.00	19.10	19.18	9.48	63.96	6.06	2.04	8.10
Average:										5.75 %
Cascade Natural	9.00	0.98	18.05	10.39	10.52	8.94	39.30	3.51	0.38	3.90
Average Including Cascade:										5.38 %

Source: *The Value Line Investment Survey*: September 15, 2006 (Issue 3).

- Notes:
- [1] 2009-2011 estimated return on common equity, dividends per share, and book value per share as reported in Value Line.
 - [2] $R_{av} = (2 * R * V_{01}) / (V_{01} + V_{00})$.
 - [3] $B = 1 - (D_e / (R_{av} * V_e))$.
 - [4] $B * R = B * R_{av} = (R_{av} - D_e / V_e)$.
 - [5] S*V equals five year average of S, multiplied by current V, where S = annual growth rate of common shares outstanding and V = fraction of new funds provided that accrues to original shareholders.

Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility
Comparable Group
S and V Estimation

Company	Growth Rate of Common Shares Outstanding (S)					Average S ¹	V ²	S*V (h)=[(f)*(g)]
	1999 (a)	2000 (b)	2001 (c)	2002 (d)	2003 (e)			
1 Nicor	(0.0240)	(0.0088)	0.0007	0.0014	0.0018	(0.0058)	0.6013	(0.0035)
2 Northwest Nat. Gas	0.0000	0.0143	0.0137	0.0621	0.0011	0.0182	0.4724	0.0086
3 Piedmont Natural Gas	0.0172	0.0193	0.0171	0.1391	0.0004	0.0386	0.5688	0.0220
4 Southwest Gas	0.0246	0.0246	0.0282	0.0748	0.0690	0.0443	0.4599	0.0204
Cascade Natural Gas	0.0000	0.0000	0.0072	0.0126	0.0124	0.0064	0.5950	0.0038

Source: *The Value Line Investment Survey: September 15, 2006 (Issue 3)*.

Notes:

[1] Average common shares outstanding growth rate for 2001-2005.

[2] V = (1-(2005 Book Value per Share/Average Stock Price))

Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility
Equity Issuance Expense

SEC Filing Date	Number of Shares Issued	Market Price Price/Share	Offering Price Price/Share	Proceeds	Per Share Underwriting Discounts & Commissions	Total Underwriting Discounts & Commissions	Net Proceeds ¹	Estimated Company Expenses	Selling & Issuance Costs ²
	(No.)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(Percent)
11/16/1949	1,584,238	10.75	10.25	17,030,559	0.26	413,486	15,824,953	792,119	7.08
6/4/1952	1,108,966	10.50	10.50	11,644,143	0.26	288,331	11,355,812	-	2.48
4/14/1954	1,219,856	15.20	14.00	18,541,811	0.18	224,454	16,853,530	1,524,820	9.40
2/29/1956	670,920	17.83	16.75	11,959,149	0.27	181,819	11,056,091	721,239	7.55
7/22/1956	952,033	23.38	22.00	22,253,771	0.26	247,529	20,697,197	1,309,046	6.99
7/28/1965	772,008	35.25	33.00	27,213,282	0.32	244,727	25,231,537	1,737,018	7.28
1/22/1969	1,080,811	29.00	27.00	31,343,519	0.31	330,728	28,851,169	2,161,622	7.95
10/21/1970	1,729,298	23.13	21.50	39,990,016	0.32	560,293	36,619,614	2,810,110	8.43
7/26/1972	1,902,228	25.00	23.50	47,555,700	0.30	561,157	44,141,201	2,853,342	7.18
10/10/1973	2,092,451	25.83	24.50	54,037,547	0.28	587,979	50,677,071	2,772,497	6.22
11/20/1974	2,300,000	17.63	17.50	40,537,500	0.98	2,251,700	37,998,300	287,500	6.26
8/14/1975	1,750,000	23.00	23.00	40,250,000	0.82	1,429,750	38,820,250	-	3.55
6/3/1976	2,000,000	24.00	24.00	48,000,000	0.78	1,568,000	46,432,000	-	3.27
5/31/1993	3,041,955	44.13	43.63	134,226,264	1.25	3,796,360	128,908,927	1,520,978	3.96
9/23/1997	4,500,000	49.94	49.56	224,721,000	1.36	6,133,500	216,900,000	1,687,500	3.48
9/29/1997	400,000	50.50	49.56	20,200,000	1.36	545,200	19,280,000	374,800	4.55 %
2/25/2002	20,000,000	22.95	22.50	459,000,000	0.75	14,900,000	435,100,000	9,000,000	5.21
Weighted Average³									5.11 %
Borun and Malley⁴									5.50
Average Expense⁵									5.31
Issuance Expense Adjustment⁶									94.69 %

Notes:

[1] Net Proceeds = Proceeds - Total Underwriting Discounts & Commissions

[2] Selling & Issuance Costs = (Total Underwriting Discounts & Commissions + Estimated Company's Expenses)/Proceeds

[4] Derived from company-provided issuance data. Average is weighted by proceeds.

[3] Victor M. Borun and Susan L. Malley "Total Flotation Costs for Electric Company Equity Issues," *Public Utilities Fortnightly*, February 20, 1986, pp. 33-39.

[5] Average Expense = (Weighted Average + Borun and Malley) / 2.

[6] Issuance Expense Adjustment = 100% - Average Expense

Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility
Comparable Group
Capital Asset Pricing Model (CAPM)

<u>No. Company</u>	<u>30-Year T-Bond Return (Rf)¹</u>	<u>Beta Value Line²</u>	<u>Market Risk Premium</u>	<u>CAPM Cost of Equity⁵</u>
			<u>Top-Down DCF - 30 Yr T- Bond Return^{3,4}</u>	<u>Top-Down DCF - 30 Yr T-Bond Return</u>
	%			%
1 Nicor	4.73	1.20	8.42	14.84
2 Northwest Nat. Gas	4.73	0.75	8.42	11.05
3 Piedmont Natural Gas	4.73	0.80	8.42	11.47
4 Southwest Gas	4.73	0.85	8.42	11.89
Average:		0.90		12.31
Cascade Natural Gas	4.73	0.85	8.42	11.89
Average Including Cascade:		0.89		12.23

- Notes:
- [1] From *The Value Line Selection and Opinion*, November 17, 2006.
- [2] *The Value Line Investment Survey*: September 15, 2006 (Issue 3).
- [3] The formula used is Risk Premium: $[RM - RF] = [12.89\% - 4.82\%]$
- [4] Dividend yield for S&P 500 is from Standard & Poors Online, Indices, S&P 500, Month End Data. Five-year earnings growth rate is from Yahoo! Finance (First Call) for September 20, 2004. More recent analyst estimate for the S&P 500 growth rate is not readily available.
- [5] Cost of Equity = $RF + \text{Beta} (RM - RF)$, where RF is the return on the 30-year Treasury Bond, and (RM - Rf) is the market premium computed as described in footnote [3] and [4].

Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility
DCF of the S&P 500

Dividend Yield S&P 500 ¹	1.81 %
Growth Rate S&P 500 ²	11.03 %
DCF S&P 500 ³	13.04 %
Issuance Expense	0.11 %
Total DCF S&P 500	13.15 %

Notes:

[1] From Standard & Poors S&P 500 Earnings and Estimate Report.

[2] Analyst estimate for the S&P 500 growth rate from Reuters (through Vanguard) is used.

[3] $DCF = (Div\ Yield * (1 + Growth)) + Growth$

[4] $Total\ DCF = (DCF\ S\&P\ 500)(1 - Average\ Issuance\ Expense) + Growth\ Rate\ S\&P\ 500$