Exhibit No.___(JSG-1)

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

CASE NO. PU-10-____

PREPARED DIRECT TESTIMONY OF

J. STEPHEN GASKE

**Q1. Please state your name, position and business address.**

A. My name is J. Stephen Gaske and I am a Senior Vice President of Concentric Energy Advisors, Inc., 1717 Rhode Island Avenue, Suite 630, Washington, DC 20036.

**Q2. Would you please describe your educational and professional background?**

A. I hold a B.A. degree from the University of Virginia and an M.B.A. degree with a major in finance and investments from George Washington University. I also earned a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were in finance and economics.

From 1977 to 1980, I worked for H. Zinder & Associates as a research assistant and later as supervisor of regulatory research. Subsequently, I spent a year assisting in the preparation of cost of capital studies for presentation in regulatory proceedings.

From 1982 to 1986 I undertook graduate studies in economics and finance at Indiana University where I also taught courses in public utilities, transportation, and physical distribution. During this time I also was employed as an independent consultant on

a number of projects involving public utility regulation, rate design, and cost of capital. From 1983-1986 I was coordinator for the Edison Electric Institute Electric Rate Fundamentals course. In 1986 I accepted an appointment as assistant professor at Trinity University in San Antonio, Texas, where I taught courses in financial management, investments, corporate finance, and corporate financial theory.

In 1988 I returned to H. Zinder & Associates ("HZA") and was President of the company from 2000 to 2008. In May 2008, HZA merged with Concentric Energy Advisors ("CEA") and I became a Senior Vice President of CEA.

**Q3. Have you presented expert testimony in other proceedings?**

A. Yes. I have filed testimony on the cost of capital and capital structure issues for electric, gas distribution and oil and gas pipeline operations before ten state and provincial regulatory bodies, including the North Dakota Public Service Commission, and the Comisión Reguladora de Energia de México ("CRE"). I also have testified or filed testimony or affidavits before the Federal Energy Regulatory Commission on more than thirty occasions. Topics covered in these submissions have included rate of return, capital structure, cost allocation, rate design, revenue requirements and market power. In addition, I have testified or submitted testimony on issues such as cost allocation, rate design, pricing and generating plant economics before the U.S. Postal Rate Commission, the Alberta Energy and Utilities Board, the Ontario Energy Board, the New Brunswick Energy and Utilities Board and five state public utility Commissions. During the course of my consulting career, I have conducted many studies on issues related to regulated industries and have served as

an advisor to numerous clients on economic, competitive and financial matters. I also have spoken and lectured before many professional groups including the American Gas Association and the Edison Electric Institute Rate Fundamentals courses. Finally, I am a member of the American Economic Association, the Financial Management Association, and the American Finance Association.

## I. INTRODUCTION

### A. Scope and Overview

**Q4. What is the scope of your testimony in this proceeding?**

A. I have been asked by Montana-Dakota Utilities Co. ("Montana-Dakota") to estimate the cost of common equity capital for the Company's electric utility operations in the state of North Dakota. In this testimony, I calculate the cost of common equity capital for Montana-Dakota's electric utility operations based on a Discounted Cash Flow ("DCF") analysis of a group of proxy companies that have risks similar to those of Montana-Dakota's North Dakota electric utility operations. The results of this DCF study are supported by various benchmark criteria that I have used to test the reasonableness of the DCF study results.

### B. Company Background

**Q5. Would you please describe Montana-Dakota's operations and those of its parent company, MDU Resources Group, Inc.?**

A. Montana-Dakota is a wholly-owned division of MDU Resources Group, Inc. ("MDU Resources") that is engaged in the generation, transmission and

distribution of electricity, and the distribution of natural gas, in the states of North Dakota, Montana, South Dakota, and Wyoming. MDU Resources also owns Cascade Natural Gas Co., which distributes natural gas in the states of Washington and Oregon; Intermountain Gas Company, which distributes gas in the state of Idaho; and it owns Great Plains Natural Gas Company, which distributes natural gas in southeastern North Dakota and western Minnesota. In all, the utility companies within MDU Resources serve 829,000 residential, commercial and industrial natural gas customers in 333 communities and adjacent rural areas across eight states. Through other divisions and subsidiaries, MDU Resources is engaged in utility infrastructure construction, natural gas exploration, production and transmission and also produces and markets aggregates and other construction materials.

In 2009, Montana-Dakota served a total of over 122,000 residential, commercial and industrial electric customers. As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 1, Montana-Dakota's electric assets comprised 9.5 percent of MDU Resources' total assets in 2009 and the electric utility revenues comprised 4.7 percent of the total. In addition, Montana-Dakota's operating income accounted for 7.9 percent of MDU Resources' total, excluding a non-cash write-down of the value of MDU Resources' oil and gas production assets. North Dakota accounted for 58 percent of the electric utility operating revenues, while Wyoming (11 percent), Montana (24 percent) and South Dakota (7 percent) accounted for the other 42 percent of electric utility revenues.

Montana-Dakota' North Dakota operations are primarily served by the company's own generating plants with approximately 463 MW of capacity owned by the interconnected system. Approximately 99 percent of the energy it generated came from coal-fired plants in 2009. When purchased power is included in the mix, approximately 75 percent of Montana-Dakota's electric generating needs came from its own coal-fired plants. In December 2008, Montana-Dakota announced that it intended to develop the Cedar Hills Wind Facility, a 19.5-MW generation project in southwest North Dakota and expand the Diamond Willow Wind Facility in southeast Montana from 19.5 MW to 30 MW. These projects, which are scheduled to achieve commercial operation in mid 2010, will serve to further diversify Montana-Dakota's generation portfolio to meet customer needs.

**Q6. Would you please describe Montana-Dakota's service territory?**

A. Montana-Dakota North Dakota's electric operations serve central and western North Dakota, with the largest communities being the Bismarck, Dickinson, Mandan and Williston areas. Although its operations tend to be concentrated in cities and towns, a large portion of the local economies are based on agricultural and minerals production. Petroleum is now North Dakota's leading mineral product, just ahead of sand and gravel, lime and salt. North Dakota also has some manufacturing, particularly in food processing and farm equipment. However, Montana-Dakota recently lost a large manufacturing customer – Bobcat, with approximately 27,000 MWh, which closed its Bismarck facility at the end of 2009.

## II. FINANCIAL MARKET STUDIES

### A. Criteria for a Fair Rate of Return

**Q7. Please describe the criteria which should be applied in determining a fair rate of return for a regulated company?**

A. The United States Supreme Court has provided general guidance regarding the level of allowed rate of return that will meet constitutional requirements. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the Court indicated that:

> "The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally."

The Court has further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Electric Company (320 U.S. 591, 603 (1944))*. There the Court described the relevant criteria as follows:

> "From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

Thus, the standards established by the Court in *Hope* and *Bluefield* consist of three requirements. These are that the allowed rate of return should be:

1. commensurate with returns on enterprises with corresponding risks;

2. sufficient to maintain the financial integrity of the regulated company; and,

3. adequate to allow the company to attract capital on reasonable terms.

These legal criteria will be satisfied best by employing the economic concept of the "cost of capital" or "opportunity cost" in establishing the allowed rate of return on common equity. For every investment alternative, investors consider the risks attached to the investment and attempt to evaluate whether the return they expect to earn is adequate for the risks undertaken. Investors also consider whether there might be other investment opportunities that would provide a better return relative to the risk involved. This weighing of alternatives and the highly competitive nature of capital markets causes the prices of stocks and bonds to adjust in such a way that investors can expect to earn a return that is just adequate for the risks involved. Thus, for any given level of risk there is a return that investors must expect in order to induce them to voluntarily undertake that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return.

**Q8. How should a fair rate of return be evaluated from the standpoint of consumers and the public?**

A. The same standards should apply. When a regulated entity faces competition, consumers will implicitly determine the fair rate of return by their consumption decisions. When regulation is appropriate, consumers and the public have a long-term interest in seeing that the regulated company has an opportunity to earn returns that are not so high as to be excessive, but that also are sufficient to encourage continued replacement and maintenance, as well as needed expansions, extensions, and new services. Thus, the consumer and public interest also lies in establishing a return that will readily attract capital without being excessive.

**Q9. How are the costs of preferred stock and long-term debt determined?**

A. For purposes of setting regulated rates, the current, embedded costs of preferred stock and long-term debt are used in order to ensure that the company receives a return that is sufficient to pay the fixed dividend and interest obligations that are attached to these sources of capital.

**Q10. How is the cost of common equity determined?**

A. The practice in setting a fair rate of return on common equity is to use the current market cost of common equity in order to ensure that the return is adequate to attract capital and is commensurate with returns available on other investments with similar levels of risk. However, determining the market cost of common equity is a relatively complicated task that requires analysis of many factors and some degree of judgment by an analyst. The current market cost of capital for securities that pay a

fixed level of interest or dividends is relatively easy to determine. For example, the current market cost of debt for publicly-traded bonds can be calculated as the yield-to-maturity, adjusted for flotation costs, based on the current market price at which the bonds are selling. In contrast, because common stockholders receive only the residual earnings of the company, there are no fixed contractual payments which can be observed. This high degree of uncertainty associated with the dividends that eventually will be paid greatly complicates the task of estimating the cost of common equity capital. For purposes of this testimony, I have relied on several analytical approaches for estimating the cost of common equity. My primary approach relies on several DCF analyses. In addition, I have conducted Risk Premium and Alternative Equity Investment analyses in order to establish benchmarks for a reasonable rate of return. Each of these approaches is described later in this testimony.

B. Interest Rates and the Economy

**Q11. What are the general economic factors that affect the cost of capital?**

A. Companies attempting to attract common equity must compete with a variety of alternative investments. Prevailing interest rates and other measures of economic trends influence investors' perceptions of the economic outlook and its implications on both short- and long-term capital markets. Page 1 of Schedule 1 of Exhibit No.___(JSG-2) shows various general economic statistics. Real growth in the Gross Domestic Product ("GDP") has averaged 2.7 percent annually during the past 30 years, 2.6 percent for the past 20 years and 1.9 percent for the

past 10 years. However, real GDP growth increased at an annual rate of 5.6 percent in the fourth quarter of 2009, supporting the projections that the economy will continue to emerge from recession in 2010, with an expected growth in GDP of 2.5 percent. The Federal Reserve has increased its discount rate to 0.75 percent for loans to banks, further signaling that the immediate financial crisis has passed, but unemployment rates remain at unusually high levels. As Page 2 of Schedule 1 of Exhibit No. ___(JSG-2) shows, interest rates on longer-term, intermediate quality corporate bonds have declined since the first half of 2009, and they are now at close to the same level as they were in early 2007.

In addition, credit spreads decreased significantly in the second half of 2009 and have remained relatively stable during the first quarter of 2010. In the last half of 2008, credit spreads rose to unusually high levels, a condition that many market experts attribute to the "flight to safety" in the aftermath of the global economic crisis, which commenced in the 3rd quarter of 2008 with the failure of many borrowers to make payments on sub-prime mortgages that banks were encouraged, and sometimes required, to make under Federal financial regulatory policies. The concept of the "flight to safety" is that risk-averse investors flock to the least risky government-backed securities, lowering the yield on those securities, but significantly increasing the capital costs associated with the more risky corporate debt. The credit spread for A-rated and Baa-rated corporate utility bonds more than doubled in the period from January 2008 to December 2008,

while long-term treasury yields were largely declining. By the end of 2009, bond yields returned to early 2008 levels, while credit spreads also have declined.

The net impact is a return to pre-crisis borrowing costs, with recent yields on A-rated public utility bonds at approximately 5.84 percent and the yields on Baa-rated public utility bonds at approximately 6.22 percent.

Investors also are influenced by the level of inflation, which has been persistent in the past. During the past decade, the Consumer Price Index has increased at an average annual rate of 2.6 percent and the GDP Implicit Price Deflator, a measure of price changes for all goods produced in the United States, has increased at an average rate of 2.4 percent. According to Blue Chip, the Consumer Price Index is forecasted to increase by 2.2 percent and 1.9 percent for 2010 and 2011, respectively.[1]

**Q12. How are current economic conditions reflected in the equity markets?**

A. Although bond yields have returned to pre-crisis levels, the equity markets generally have not fully recovered from the large stock market decline in 2008-2009. This suggests that the cost of common equity generally is higher than it was before the significant risks of equity investment were emphasized during the recent market downturn.

[1] Blue Chip Economic Indicators, *Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, Vol. 35, No. 3 March 10, 2010, at 1.

C. Discounted Cash Flow ("DCF") Method

**Q13. Please describe the DCF method of estimating the cost of common equity capital.**

A. The DCF method reflects the assumption that the market price of a share of stock represents the discounted present value of the stream of all future dividends that investors expect the firm to pay. The DCF method suggests that investors in common stocks expect to realize returns from two sources: a current dividend yield, plus expected growth in the value of their shares as a result of future dividend increases. Estimating the cost of capital with the DCF method therefore is a matter of calculating the current dividend yield and estimating the long-term future growth rate in dividends that investors reasonably expect from a company.

The dividend yield portion of the DCF method utilizes readily-available information regarding stock prices and dividends. The market price of a firm's stock reflects investors' assessments of risks and potential earnings as well as their assessments of alternative opportunities in the competitive financial markets. By using the market price to calculate the dividend yield, the DCF method implicitly recognizes investors' market assessments and alternatives. However, the other component of the DCF formula, investors' expectations regarding the future long-run growth rate of dividends, is not readily apparent from stock market data and must be estimated using informed judgment.

**Q14. What is the appropriate DCF formula to use in this proceeding?**

A. There can be many different versions of the basic DCF formula, depending on the assumptions that are most reasonable regarding the timing of future dividend payments. In my opinion, it is most appropriate to use a model that is based on the assumptions that dividends are paid quarterly and that the next annual dividend increase is a half year away. One version of this quarterly model assumes that the next dividend payment will be received in three months, or one quarter. This model multiplies the dividend yield by (1 + .75 g). Another version assumes that the next dividend payment will be received today. This model multiplies the dividend yield by (1 + .5 g). Since, on average, the next dividend payment is a half quarter away, the average of the results of these two models is a reasonable approximation of the average timing of dividends and dividend increases that investors can expect from companies that pay dividends quarterly. The average of these two quarterly dividend models is:

$$K = \frac{D_0 (1 + .625g)}{P} + g \qquad (1)$$

where:

- $K$ = the cost of capital, or total return that investors expect to receive;
- $P$ = the current market price of the stock;
- $D_0$ = the current annual dividend rate; and
- $g$ = the future annual growth rate that investors expect.

In my opinion, this is the DCF model that is most appropriate for estimating the cost of common equity capital for companies that pay dividends quarterly, such as those used in my analysis.

D. Flotation Cost Adjustment

**Q15. Does the investor return requirement that is estimated by a DCF analysis need to be adjusted for flotation costs in order to estimate the cost of capital?**

A. Yes. There are significant costs associated with issuing new common equity capital and these costs must be considered in determining the cost of capital. Schedule 3 of Exhibit No. ___(JSG-2) shows a representative sample of flotation costs incurred with 93 new common stock issues by electric companies from 2000 to 2009. Flotation costs associated with these new issues averaged 3.63 percent.

This indicates that in order to be able to issue new common stock on reasonable terms, without diluting the value of the existing stockholders' investment, Montana-Dakota must have an expected return that places a value on its equity that is approximately 3.6 percent above book value. The cost of common equity capital is therefore the investor return requirement multiplied by 1.036.

One purpose of a flotation cost adjustment is to compensate common equity investors for past flotation costs by recognizing that their real investment in the company exceeds the equity portion of the rate base by the amount of past flotation costs. For example, the proxy companies generally have incurred flotation costs in the past and, thus, the cost of capital invested in these companies is the investor return requirement plus an adjustment for flotation costs. A more important purpose of a flotation cost adjustment is to establish a return that is sufficient to enable a company to attract capital on reasonable terms. This fundamental requirement of a

fair rate of return is analogous to the well-understood basic principle that a firm, or an individual, should maintain a good credit rating even when they do not expect to be borrowing money in the near future. Regardless of whether a company can confidently predict its need to issue new common stock several years in advance, it should be in a position to do so on reasonable terms at all times without dilution of the book value of the existing investors' common equity. This requires that the flotation cost adjustment be applied to the entire common equity investment and not just a portion of it.

E. DCF Study of Electric Utility Companies

**Q16. Would you please describe the overall approach used in your DCF analysis of Montana-Dakota's cost of common equity?**

A. Because Montana-Dakota must compete for capital with many other potential projects and investments, it is essential that it have an allowed return that matches returns potentially available from other similarly risky investments. The DCF method provides a good measure of the returns required by investors in the financial markets. However, the DCF method requires a market price of common stock to compute the dividend yield component of the DCF analysis. Since Montana-Dakota is a division of MDU Resources and does not have publicly-traded common stock, a direct, market-based DCF analysis of Montana-Dakota's electric utility operation as a stand-alone company is not possible. As an alternative, I have used a group of electric utilities that have publicly-traded common stock as a proxy group for

purposes of estimating the cost of common equity for Montana-Dakota's North Dakota electric utility operations.

**Q17. How did you select a group of electric utility proxy companies?**

A. I started with a list of 54 electric utility and combination companies covered by Value Line and selected those that owned regulated generation capacity with at least 25 percent of net generation produced from coal-fired facilities, and whose total electric utility assets comprised at least 85 percent of their total consolidated assets. From that group, I eliminated any companies that did not have investment-grade bond ratings with either Standard & Poor's or Moody's (now called Mergent). In addition, I excluded any companies that did not pay dividends or that did not have future growth rate estimates provided by both Value Line and Zack's. When there was no published Zacks growth rate for a potential proxy group company, I substituted a consensus growth estimate from Yahoo! First Call in place of the Zacks growth estimate. As shown on Exhibit No. ___(JSG-2), page 1 of Schedule 2, thirteen electric utility proxy companies met these criteria.

**Q18. How did you calculate the dividend yields for the companies in your comparison group?**

A. These calculations are shown on page 3 of Schedule 2 of Exhibit No. __(JSG-2). For the price component of the calculation I used the average of the high and low stock prices experienced by each company during the six month period from October 2009 to March 2010. The dividend yields were calculated for each company by using the average indicated annual dividend for the period divided by

the average of the stock prices for each company. These dividend yields can be multiplied by the quarterly DCF model factor (1 + .625 g) to arrive at the dividend yield component of the DCF model.

**Q19. Please describe the method you used in estimating the future growth rate that investors expect from this group of companies?**

A. I developed two different DCF analyses of the proxy companies based on two different growth rate estimation methods. There are many methods that reasonably can be employed in formulating a growth rate estimate, but an analyst must attempt to ensure that the end result is an estimate that fairly reflects the forward-looking growth rate that investors expect.

In the first approach I calculated a DCF rate of return using a combination of securities analysts' growth projections and the Value Line retention growth forecasts to produce a Second-Stage Retention Growth analysis. As a second approach, I conducted a Basic DCF analysis that relied solely on the analysts' forecasts for the growth rate component of the model.

F. Second-Stage Retention Growth Analysis

**Q20. How did you use your Second-Stage Retention Growth analysis to estimate investors' long-term growth rate expectations for the proxy companies?**

A. The Second-Stage Retention Growth rate approach combines: (i) estimates of long-term growth for each company that are published by various investment analysts and (ii) Value Line retention growth forecasts.

**Q21. How did you estimate the first stage of expected future growth?**

A. Among the best sources of information regarding investors' growth rate expectations are the long-term earnings growth rate forecasts of investment analysts. Zack's is a service that collects estimates by professional investment analysts and publishes a summary of the consensus forecasts. I have used the Zack's consensus forecasts as the source for analysts' forecasts in my calculations. When Zacks data were missing, I substituted growth rates from Yahoo! First Call. As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 5, the average of the analysts' long-term growth rate estimates for the electric utility proxy companies is 5.85 percent.

**Q22. Would you please describe the second stage, retention growth rate component of your analysis?**

A. In addition to analysts' growth rate forecasts, I have relied upon Value Line projections of the retention growth rates that the proxy companies are expected to begin maintaining three to five years in the future. Although companies may experience extended periods of growth for other reasons, in the long-run, growth in earnings and dividends per share depends in part on the amount of earnings that are being retained and reinvested in a company. Thus, the primary determinants of growth for the proxy companies will be (i) their ability to find and develop profitable opportunities; (ii) their ability to generate profits that can be reinvested in order to sustain growth; and, (iii) their willingness and inclination to reinvest available profits. Expected future retention rates provide a general measure of these determinants of expected growth, particularly items (ii) and (iii).

**Q23. How can a company's earnings retention rate affect its future growth?**

A. Retention of earnings causes an increase in the book value per share and, other factors being equal, increases the amount of earnings that are generated per share of common stock. The retention growth rate can be estimated by multiplying the expected retention rate (b) times the rate of return on common equity (r) that a company is expected to earn in the future. For example, a company that is expected to earn a return of 15 percent and retain 80 percent of its earnings might be expected to have a growth rate of 12 percent, computed as follows:

$$.80 \times 15\% = 12\%$$

On the other hand, another company that is also expected to earn 15 percent but only retains 20 percent of its earnings might be expected to have a growth rate of 3 percent, computed as follows:

$$.20 \times 15\% = 3\%$$

Thus, the rate of growth in a firm's book value per share is primarily determined by the level of earnings and the proportion of earnings retained in the company.

**Q24. How did you calculate the expected future retention rates of the proxy companies?**

A. For most companies, Value Line publishes forecasts of data that can be used to estimate the retention rates that its analysts expect individual companies to have 3-5 years in the future. Since these retention rates are projected to occur several years in the future they should be indicative of a normal expectation for a primary underlying determinant of growth that would be sustainable indefinitely beyond the period

covered by analysts' forecasts. While companies may have either accelerating or decelerating growth rates for extended periods of time, the retention growth rates expected to be in effect 3-5 years in the future generally represent a minimum "cruising speed" that companies can be expected to maintain indefinitely. The derivation of Value Line's retention growth rate forecasts for each of the proxy companies is shown on page 4 of Schedule 2 of Exhibit No.___(JSG-2). The projected earnings per share and projected dividends per share can be used to calculate the percentage of earnings per share that are being retained and reinvested in the company. This earnings retention rate is multiplied times the projected return on common equity to arrive at the projected retention growth rate. The average retention growth rate for the proxy companies is 4.31 percent.

**Q25. How did you utilize the projected earnings retention rates in estimating expected growth for the proxy companies?**

A. As shown on page 5 of Schedule 2 of Exhibit No.___(JSG -2), I calculated a weighted average of the analysts' projected growth rates and the projected retention growth rates to derive long-term growth rate estimates for each of the proxy companies. In these calculations, I gave a two-thirds weighting to the analysts' growth rate projections to reflect the fact that analysts are attempting to evaluate all sources of growth and not just growth that is expected to result from retained earnings. This weighting also reflects the fact that the analysts' long-term growth forecasts can be expected to prevail for a relatively long period of time in the future.

The average of the weighted average growth rates for the proxy companies is 5.34 percent and the median is 5.00 percent.

**Q26. How did you utilize these Second-Stage Retention Growth rate estimates in estimating the return on common equity capital that investors require from the proxy companies?**

A. The dividend yield for each company shown on page 3 of Schedule 2 of Exhibit No.___(JSG-2) is multiplied times the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Finally, the investor return requirement is multiplied times the flotation cost adjustment factor, 1.036 to arrive at the cost of common equity capital for the proxy companies. These calculations are shown on page 6 of Schedule 2 of Exhibit No.___(JSG-2). This Second-Stage Retention Growth DCF analysis indicates that the cost of common equity capital for the electric utility proxy companies is in a range between 8.8 percent and 12.8 percent. The median for the group is 10.8 percent and the average for the group is 10.9 percent. In addition, the bottom of the fourth quartile of these results is 12.1 percent, which means that one-fourth of the companies had DCF results above 12.1 percent when the Second-Stage Growth rate is used in the analysis.

G. Basic DCF Analysis

**Q27. What approach did you use in conducting a Basic DCF analysis?**

A. This analysis is conducted in substantially the same manner as the Second-Stage Retention Growth Rate analysis. However, the growth rate component of the analysis is based solely on the analysts' forecasts for each company and the retention growth rate component is omitted from the analysis. This Basic DCF analysis recognizes that the consensus of analysts' forecasts reflects the most important component of investors' growth rate expectations and it assumes that the analysts' forecasts incorporate all information required to estimate a long-term expected growth rate for a company.

**Q28. How did you calculate the cost of capital using the Basic DCF analysis?**

A. These calculations are shown on page 7 of Schedule 2 of Exhibit No.___(JSG-2). Again, the annual dividend yield is multiplied times the quarterly dividend adjustment factor (1 + .625g) and this product is added to the growth rate estimate to arrive at the investor-required return. Then, the investor return requirement is multiplied times the flotation cost adjustment factor, 1.036, to arrive at the Basic DCF estimate of the cost of common equity capital for the proxy companies. The Basic DCF analysis indicates a median cost of common equity for the proxy companies of 11.3 percent and an average cost of 11.5 percent. In this analysis, the bottom of the fourth quartile is 13.1 percent, which means that one-fourth of the companies had DCF results greater than 13.1 percent.

H. Risk Premium Analyses

**Q29. Have you conducted additional analyses in determining the cost of capital to Montana-Dakota?**

A. Yes. The risk premium approach provides a general guideline for determining the level of returns that investors expect from an investment in common stocks. Investments in the common stocks of companies carry considerably greater risk than investments in bonds of those companies since common stockholders receive only the residual income that is left after the bondholders have been paid. In addition, in the event of bankruptcy or liquidation of the company, the stockholders' claims on the assets of a company are subordinated to the claims of bondholders. This superior standing provides bondholders with greater assurances that they will receive the return on investment that they expect and that they will receive a return of their investment when the bonds mature. Accompanying the greater risk associated with common stocks is a requirement by investors that they can expect to earn, on average, a return that is greater than the return they could earn by investing in less risky bonds. Thus, the risk premium approach estimates the return investors require from common stocks by utilizing current market information that is readily available in bond yields and adding to those yields a premium for the added risk of investing in common stocks.

Investors' expectations for the future are influenced to a large extent by their knowledge of past experience. Ibbotson Associates annually publishes extensive data regarding the returns that have been earned on stocks, bonds and U.S. Treasury

bills since 1926. Historically, the annual returns on large company common stocks have exceeded the returns on long-term corporate bonds by a premium of 560 basis points (5.6 percent) annually over a long period of time in the past.[2] When this premium is added to the 5.8 percent yield on Moody's corporate bonds that has prevailed in recent months, the result is an investor return requirement for large company stocks of 11.4 percent. However, over the long term companies in Montana-Dakota's size range have had a premium of 1,080 basis points (10.8 percent) over the average returns on long-term corporate bonds. When added to the recent average corporate bond yields, this size-related premium suggests an expected return of 16.6 percent.[3]

I. Alternative Equity Investment Analysis

**Q30. Have you analyzed the returns available on common equity investments in other industries?**

A. Yes. When investors consider whether to invest their funds in a particular company or line of business, they evaluate the returns potentially available from other companies. This process, whereby projects and companies compete for scarce equity capital, ensures that capital resources are deployed efficiently. As a result, regulated electric utility operations must bid against other companies and other possible projects within the same company for equity capital by offering potential returns that investors find attractive relative to the risks involved.

2 2009 Ibbotson SBBI Valuation Yearbook, pg 23

3 2009 Ibbotson SBBI Valuation Yearbook, pgs 90 and 93.

**Q31. What level of returns is potentially available to unregulated companies?**

A. The potential returns are often considerably above 20 percent and the average returns for broad-based, diversified portfolios have averaged 20.0 percent or more in recent years. For purposes of comparison with allowed returns for regulated electric operations, a good indicator of earnings on alternative equity investments is provided by data on 566 industrial, retail and transportation companies published by *The Value Line Investment Survey*. Excluding extraordinary and non-recurring items, the average returns on the original cost book value of common equity for these companies in recent years have been:

| | |
|---|---|
| 2004 | 31.47% |
| 2005 | 34.64 |
| 2006 | 38.69 |
| 2007 | 39.08 |
| 2008 | 37.25 |
| **5-year Average** | **36.22%** |

**Q32. Is it appropriate to set the allowed rate of return for an electric utility company equal to the average return available to industrial companies?**

A. The average return for industrials serves as a useful indicator of the cost of capital because electric utility companies must offer potential returns that are competitive with other investments in order to attract capital. It is important to remember that an industrial company has an opportunity to earn returns far in excess of 20 percent. In fact, the average company has earned normal returns on the book value of equity well in excess of 20 percent in recent years. This average reflects many companies that experienced enormous losses as well as those with large returns.

Similarly, when a regulator sets an allowed return it is providing only an *opportunity* to earn that return. During times when its services are most highly valued and it sells greater quantities of service or reduces costs, a regulated company might earn more than this amount, but it might also earn substantially less than the allowed return. Electric utility companies generally have risks that are less than those of the average large industrial company. Consequently, it would be appropriate to view average returns earned by a broad cross-section of industry as being only a general indicator for reasonable allowed returns.

As a benchmark, allowed returns for electric utility companies can be compared to returns on original cost book value for large companies. Normal returns have averaged 36.2 percent during the past five years. As this comparison indicates, an allowed return of 12.0 percent for Montana-Dakota would be quite low in comparison with the returns earned by other large companies.

J. Relative Risk Analysis

**Q33. Have you compared the risks faced by Montana-Dakota's North Dakota electric utility operations with the risks faced by the proxy group of companies?**

A. Yes. There are four broad categories of risk that concern investors. These include:

i. Business Risk;
ii. Regulatory Risk;
iii. Financial Risk; and,
iv. Market Risk.

**Q34. Would you please describe the business risks inherent in the electric industry?**

A. Business risk refers to the ability of the firm to generate revenues that exceed its cost of operations. Business risk exists because forecasts of both demand and costs are inherently uncertain. Markets change and the level of demand for the firm's output may be sufficient to cover its costs at one time and later become insufficient. Sunk investments in long-lived electric utility assets, for which cost recovery occurs over a period of thirty years or more, are subject to enormous uncertainties and risks that demand, costs, supply and competition may change in ways that adversely affect the value of the investment.

The business model of Montana-Dakota and other major utilities is based on the fact that traditionally electricity has been provided most efficiently by large, centralized generating plants connected to the market with extensive networks of transmission and distribution lines. However, in the future, demand for Montana-Dakota's electric services could be affected by the adoption of distributed generation technologies that allow customers to generate their own power instead of relying on utility generation, transmission or distribution. The overall efficiency of these technologies has improved significantly in recent years and some electricity consumers have begun installing and using distributed generation equipment. Shifts in the overall cost of distributed generation relative to the fuel and network costs of centralized utility generation could imperil the ability of some utilities to recover the investments they have made under the traditional "public utility model" of electricity supply.

In addition, the constantly-changing mandates of environmental laws disproportionately impact electric utilities, especially coal-burning utilities. Litigation expenses and exposure to tort claims also is an increasingly important consideration for electric utility investors.

**Q35. What are some of the business risks faced by Montana-Dakota's North Dakota electric operations?**

A. These operations face many of the same risks that are associated with other electric utilities. As shown on Exhibit No. ___ (JSG-2), Schedule 2, page 1, Montana-Dakota's electric utility operations are considerably smaller than the operations of any of the proxy companies and a small fraction of the size of the typical proxy company. For example, Montana-Dakota's electric utility assets are equal to only 6.7 percent of the assets of the median proxy company. Similarly, Montana-Dakota's electric operating revenues and operating income are only 10.0 percent and 10.4 percent of the level for the median proxy company, respectively. Thus, depending upon the measure of size, the typical proxy company is somewhere between 10 and 15 times the size of Montana-Dakota's electric utility operations.

This smaller size has significant implications for business risks. As noted earlier, Ibbotson Associates has documented the significantly higher returns that generally have been associated with small companies. In addition, demographic trends cause Montana-Dakota's North Dakota electric utility operations to be riskier than the operations of the utilities in the proxy group. Though the

population in North Dakota has experienced modest increases in recent years, the population in rural areas served by Montana-Dakota's electric utility operations is shrinking as people migrate to more urban areas. As shown on Exhibit No. ___(JSG-2), page 3 of Schedule 1, there has been a 0.48 percent decline in population since 2000 for counties in which Montana-Dakota provides electric service. Because these larger urban areas are also served by rural electric cooperatives, the growth of Montana-Dakota's electric utility operations in these urban areas is significantly limited since these rural electric cooperatives tend to serve the new areas of these cities. Consequently, a long-term problem and source of risk for Montana-Dakota derives from the fact that its investments in facilities to serve its customers are sunk and have a long life. These facilities cannot be easily moved or devoted to another purpose, even if the population declines significantly. The population shifts that are occurring in Montana-Dakota's service territory pose a significant risk that it may at some point be unable to recover the cost of its investments.

In addition, Montana-Dakota's generation portfolio is heavily reliant on coal. Utilities with generation that is heavily weighted toward one fuel source face greater risks that adverse circumstances will arise that render much of their generating capacity uneconomic. Montana-Dakota's customers have benefited greatly from the company's use of low-cost coal, but there is an element of risk associated with this undiversified generating mix. For example, federal legislation that will significantly limit carbon dioxide emissions remains a very

real possibility. If restrictions on carbon dioxide were to be enacted, coal-fired generation would be disproportionately impacted. Similarly, as natural gas prices continue to decline, coal-fired generation faces increased risk of becoming uneconomic. In fact, most new generation constructed in recent years has been fueled with natural gas as a result of low gas prices and new, efficient generating technologies.

**Q36. What are the regulatory risks faced by Montana-Dakota's North Dakota utility operations?**

A. Regulatory risk is closely related to business risk and might be considered just another aspect of business risk. To the extent that the market demand for an electric utility company's services is sufficiently strong that the company could conceivably recover all of its costs, regulators may nevertheless set the rates at a level that will not allow full cost recovery. In effect, the binding constraint on electric utilities is often posed by regulation rather than by the working of market forces. One purpose of regulation is to provide a substitute for competition where markets are not workably competitive. As such, regulation often attempts to replicate the type of cost discipline and risks that might typically be found in highly competitive industries.

Moreover, there is the perceived risk that regulators may set allowed returns so low as to effectively undermine investor confidence and jeopardize the ability of electric utilities to finance their operations. Thus, in some instances regulation may substitute for competition and in other instances it may limit the potential

returns available to successful competitors. In either case, regulatory risk is an important consideration for investors and has a significant effect on the cost of capital for all firms in the electric utility industry. Regulatory Research Associates ranks the regulatory climate in North Dakota as being "Average". Consequently, the regulatory risk faced by Montana-Dakota in North Dakota generally would be considered to be average also.

**Q37. Would you please describe Montana-Dakota's relative financial risks?**

A. Financial risk exists to the extent a company incurs fixed obligations in financing its operations. These fixed obligations increase the level of income which must be generated before common stockholders receive any return and serve to magnify the effects of business and regulatory risks. Fixed financial obligations also increase the probability of bankruptcy by reducing the company's financial flexibility and ability to respond to adverse circumstances. One possible indicator of investors' perceptions of relative financial risk in this case might be obtained from bond ratings. Because Montana-Dakota, as a division of MDU Resources, does not have its own bonds outstanding, it is difficult to make direct comparisons between the ratings of Montana-Dakota and the proxy group. However, page 2 of Schedule 2 of Exhibit No. ___ (JSG-2) shows the bond ratings assigned by Moody's and Standard & Poor's to each of the companies in the comparison group and MDU Resources bonds.

The median bond ratings for companies in the proxy group are BBB for Standard & Poor's and Baa2 for Moody's. In comparison, MDU Resources long term debt

carries a BBB+ rating with Standard & Poor's and a Baa1 rating with Moody's. This suggests that the perceived risk of MDU Resources' bonds is reasonably aligned with that of the typical company in the comparison group. The capital structure data shown on Schedule 2, page 8, in Exhibit No. ___ (JSG-2) show that Montana-Dakota's filed common equity ratio, 52.3 percent, is several percentage points greater than the 44.7 percent median for the proxy companies. This common equity ratio, combined with its bond rating, suggests below-average financial risk for Montana-Dakota's North Dakota electric utility operations.

**Q38. Would you please describe Montana-Dakota's market risks?**

A. Market risk is associated with the changing value of all investments because of business cycles, inflation and fluctuations in the general cost of capital throughout the economy. Different companies are subject to different degrees of market risk largely as a result of differences in their business and financial risks. Overall, Montana-Dakota's market risk is comparable to that of the companies in the electric utility comparison group.

**Q39. How do the overall risks of the proxy companies compare with the risks faced by Montana-Dakota's electric utility operations?**

A. Montana-Dakota's North Dakota electric operation faces overall risks that are slightly higher than those of the typical proxy company primarily because Montana-Dakota is smaller and operates in a relatively undiversified local economy. The "average" rating for the regulatory climate in North Dakota is neutral in its effect on investors' perception of the overall risks of Montana-

Dakota's North Dakota electric utility operations relative to the proxy companies. Consequently, Montana-Dakota requires an allowed rate of return that is in the range of the median returns and the 3rd quartile returns, for the companies in the proxy group indicated by my Basic DCF analysis and my Second-Stage Retention Growth DCF analysis.

## III. SUMMARY AND CONCLUSIONS

**Q40. Would you please summarize the results of your cost of capital study?**

A. Yes. I conducted two DCF analyses on a group of electric utility companies that have a range of risks that includes risks roughly comparable to those of Montana-Dakota. These results can be summarized as follows:

| | Results of DCF Analyses | |
|---|---|---|
| | 2nd Stage Retention Growth | Basic Analysis |
| High | 12.79% | 13.68% |
| **3rd Quartile** | **12.06%** | **13.13%** |
| **Median: 2nd Quartile** | **10.77%** | **11.29%** |
| 1st Quartile | 10.33% | 10.04% |
| Low | 8.81% | 8.94% |
| **Benchmark Analyses** | | |
| - Corporate Bonds | | |
| v. Large Companies | 11.4% | |
| v. Small Companies | 16.6% | |
| Alternative Investments | | |
| - Value Line Industrials | 36.22% | |

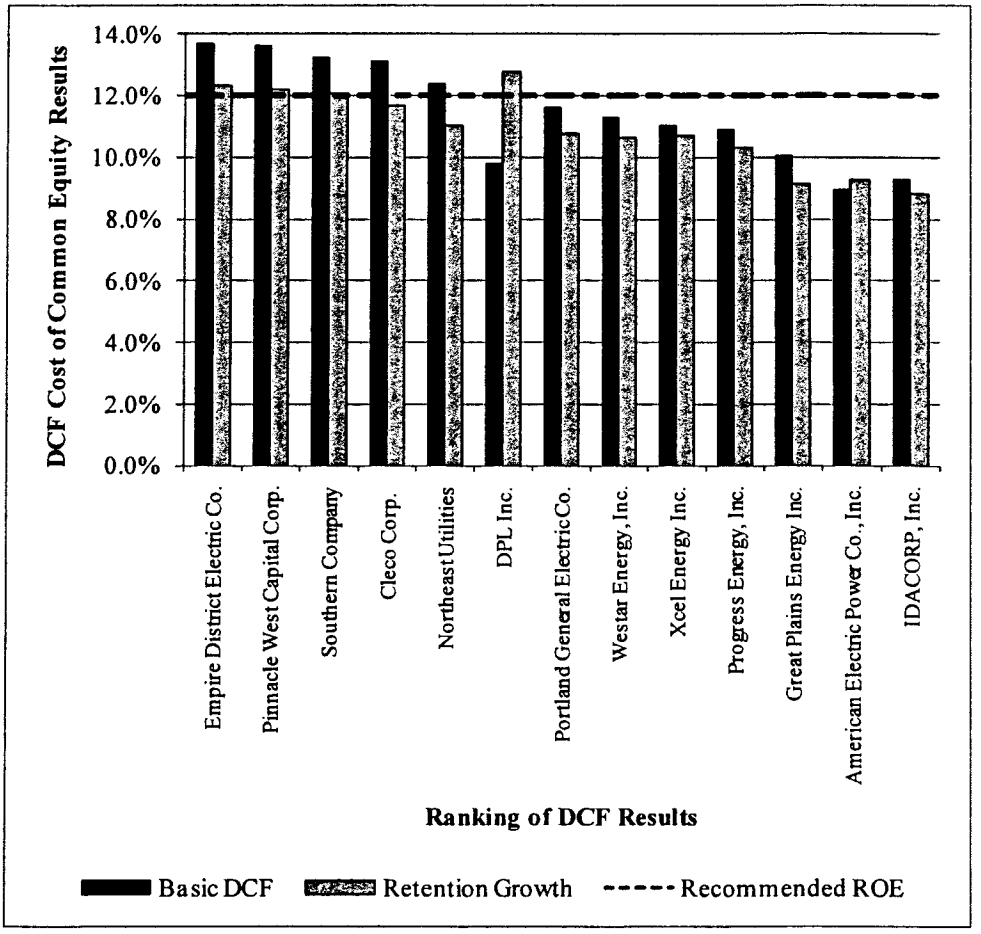
My second-stage retention growth analysis indicates a median cost of common equity capital of 10.8 percent and a 3rd Quartile return of 12.1 percent. Because

projected retention growth is sustainable indefinitely and it is directly related to the growth rate expectations for an individual company, it is a good indicator of the minimum growth rate that a company can maintain in the very long run. However, companies can achieve growth through means in addition to retained earnings. Consequently, analysts' forecasts provide the best measure of expected growth for the foreseeable future. Combining these two measures provides a good estimate of the long-term growth that investors can reasonably expect from these proxy companies.

The Basic DCF analysis, which relies solely on the analysts' forecasts, also provides a good estimate of investors' growth rate expectations and required return for the proxy companies. This DCF analysis indicates a median required rate of return of 11.3 percent and a 3rd Quartile return of approximately 13.1 percent. Figure 1 shows the results of my DCF analyses of the cost of common equity.

My risk premium analyses indicate that my DCF estimates produce a premium over the corporate bond yield that is below the average long-run risk premium available from common stocks. The DCF return estimates provide a premium over the return on corporate bonds that is considerably below the average premium experienced by companies in Montana-Dakota's relative size range. In addition, my examination of returns available on alternative equity investments suggests that my DCF estimates generally are far below the 36.22 percent average normal returns earned by the Value Line Industrials in recent years.

**Figure 1: DCF Results and Cost of Equity for Montana-Dakota**




**Q41. What rate of return on common equity do you recommend for Montana-Dakota in this proceeding?**

A. My analyses indicate that an appropriate rate of return on common equity for Montana-Dakota's North Dakota electric utility operations at this time is 12.0 percent. This recommended return reflects my assessment that Montana-Dakota's overall risks are substantially similar to, but slightly higher than, those of the proxy group.

A return of 12.0 percent is within the range of third quartile values of 10.8 – 12.1 percent and 11.3 – 13.1 percent, for both the Second-Stage Retention Growth Rate analysis and the Basic DCF analysis, respectively. Thus, my recommended return is appropriately positioned to reflect the risks faced by Montana-Dakota's North Dakota electric operations in comparison with the range of risks faced by the proxy companies.

**Q42. Does this conclude your Prepared Direct Testimony?**

A. Yes.

# Montana-Dakota Utilities Co.

## General Economic Statistics

*1980-2009*

| Year | Percentage Price Changes: Consumer Price Index | Percentage Price Changes: GDP Implicit Price Deflator | Real GDP Growth | Nominal GDP ($Billions) | Nominal GDP Growth |
|---|---|---|---|---|---|
| 1980 | 13.5% | 9.1% | -0.3% | 2,788.1 | 8.8% |
| 1981 | 10.3% | 9.4% | 2.5% | 3,126.8 | 12.1% |
| 1982 | 6.2% | 6.1% | -1.9% | 3,253.2 | 4.0% |
| 1983 | 3.2% | 4.0% | 4.5% | 3,534.6 | 8.6% |
| 1984 | 4.3% | 3.8% | 7.2% | 3,930.9 | 11.2% |
| 1985 | 3.6% | 3.0% | 4.1% | 4,217.5 | 7.3% |
| 1986 | 1.9% | 2.2% | 3.5% | 4,460.1 | 5.8% |
| 1987 | 3.6% | 2.9% | 3.2% | 4,736.4 | 6.2% |
| 1988 | 4.1% | 3.4% | 4.1% | 5,100.4 | 7.7% |
| 1989 | 4.8% | 3.8% | 3.6% | 5,482.1 | 7.5% |
| 1990 | 5.4% | 3.9% | 1.9% | 5,800.5 | 5.8% |
| 1991 | 4.2% | 3.5% | -0.2% | 5,992.1 | 3.3% |
| 1992 | 3.0% | 2.4% | 3.4% | 6,342.3 | 5.8% |
| 1993 | 3.0% | 2.2% | 2.9% | 6,667.4 | 5.1% |
| 1994 | 2.6% | 2.1% | 4.1% | 7,085.2 | 6.3% |
| 1995 | 2.8% | 2.1% | 2.5% | 7,414.7 | 4.7% |
| 1996 | 3.0% | 1.9% | 3.7% | 7,838.5 | 5.7% |
| 1997 | 2.3% | 1.8% | 4.5% | 8,332.4 | 6.3% |
| 1998 | 1.6% | 1.1% | 4.4% | 8,793.5 | 5.5% |
| 1999 | 2.2% | 1.5% | 4.8% | 9,353.5 | 6.4% |
| 2000 | 3.4% | 2.2% | 4.1% | 9,951.5 | 6.4% |
| 2001 | 2.8% | 2.3% | 1.1% | 10,286.2 | 3.4% |
| 2002 | 1.6% | 1.6% | 1.8% | 10,642.3 | 3.5% |
| 2003 | 2.3% | 2.2% | 2.5% | 11,142.1 | 4.7% |
| 2004 | 2.7% | 2.8% | 3.6% | 11,867.8 | 6.5% |
| 2005 | 3.4% | 3.3% | 3.1% | 12,638.4 | 6.5% |
| 2006 | 3.2% | 3.3% | 2.7% | 13,398.9 | 6.0% |
| 2007 | 2.8% | 2.9% | 2.1% | 14,077.6 | 5.1% |
| 2008 | 3.8% | 2.1% | 0.4% | 14,441.4 | 2.6% |
| 2009 | -0.4% | 1.2% | -2.4% | 14,258.7 | -1.3% |
| Average Rate of Change: [1] | | | | | |
| 1980-2009 | 3.7% | 3.1% | 2.7% | 5.8% | 5.9% |
| 1990-2009 | 2.8% | 2.3% | 2.6% | 4.8% | 4.9% |
| 2000-2009 | 2.6% | 2.4% | 1.9% | 4.1% | 4.3% |

[1] Nominal GDP growth rates are based on the geometric average rate of change in nominal GDP.

Sources: Department of Labor, Bureau of Labor Statistics, Databases & Tables, website (http://www.bls.gov/data) and Department of Commerce, Bureau of Economic Analysis, National Economic Accounts, website (http://www.bea.gov/national/nipaweb/index.asp)

# Montana-Dakota Utilities Co.

## Bond Yield Averages
*January 2007 - March 2010*

| | | [1] | [2] | [3] | [4] | [5] | [6] |
|---|---|---|---|---|---|---|---|
| | | 30-Year | Average | Public Utility Bonds | | Credit Spreads | |
| | | T-Bonds | Corporate | A-Rated | Baa-Rated | A-Rated | Baa-Rated |
| 2007 | JAN | 4.85 | 5.92 | 5.96 | 6.16 | 1.11 | 1.31 |
| | FEB | 4.82 | 5.88 | 5.90 | 6.10 | 1.08 | 1.28 |
| | MAR | 4.72 | 5.84 | 5.85 | 6.10 | 1.13 | 1.38 |
| | APR | 4.86 | 5.99 | 5.97 | 6.24 | 1.10 | 1.37 |
| | MAY | 4.90 | 6.00 | 5.99 | 6.23 | 1.08 | 1.33 |
| | JUN | 5.21 | 6.32 | 6.30 | 6.54 | 1.10 | 1.34 |
| | JUL | 5.10 | 6.26 | 6.25 | 6.49 | 1.15 | 1.39 |
| | AUG | 4.94 | 6.26 | 6.24 | 6.51 | 1.30 | 1.57 |
| | SEP | 4.79 | 6.21 | 6.18 | 6.45 | 1.39 | 1.66 |
| | OCT | 4.78 | 6.12 | 6.11 | 6.36 | 1.33 | 1.58 |
| | NOV | 4.52 | 5.97 | 5.97 | 6.27 | 1.45 | 1.75 |
| | DEC | 4.53 | 6.15 | 6.16 | 6.51 | 1.63 | 1.98 |
| 2008 | JAN | 4.33 | 6.02 | 6.02 | 6.35 | 1.68 | 2.01 |
| | FEB | 4.51 | 6.24 | 6.21 | 6.60 | 1.70 | 2.08 |
| | MAR | 4.38 | 6.23 | 6.21 | 6.68 | 1.83 | 2.30 |
| | APR | 4.44 | 6.29 | 6.29 | 6.81 | 1.85 | 2.37 |
| | MAY | 4.60 | 6.31 | 6.28 | 6.79 | 1.68 | 2.20 |
| | JUN | 4.68 | 6.43 | 6.38 | 6.93 | 1.70 | 2.24 |
| | JUL | 4.56 | 6.44 | 6.40 | 6.97 | 1.84 | 2.41 |
| | AUG | 4.50 | 6.42 | 6.37 | 6.98 | 1.87 | 2.48 |
| | SEP | 4.27 | 6.50 | 6.49 | 7.15 | 2.22 | 2.88 |
| | OCT | 4.16 | 7.56 | 7.56 | 8.58 | 3.40 | 4.42 |
| | NOV | 3.98 | 7.65 | 7.60 | 8.98 | 3.62 | 5.00 |
| | DEC | 2.85 | 6.71 | 6.52 | 8.11 | 3.68 | 5.27 |
| 2009 | JAN | 3.10 | 6.59 | 6.39 | 7.90 | 3.29 | 4.80 |
| | FEB | 3.59 | 6.64 | 6.30 | 7.74 | 2.71 | 4.15 |
| | MAR | 3.64 | 6.84 | 6.42 | 8.00 | 2.79 | 4.36 |
| | APR | 3.76 | 6.85 | 6.48 | 8.03 | 2.73 | 4.27 |
| | MAY | 4.24 | 6.79 | 6.49 | 7.76 | 2.25 | 3.52 |
| | JUN | 4.51 | 6.52 | 6.20 | 7.30 | 1.69 | 2.79 |
| | JUL | 4.40 | 6.17 | 5.97 | 6.87 | 1.56 | 2.47 |
| | AUG | 4.37 | 5.83 | 5.71 | 6.36 | 1.34 | 1.99 |
| | SEP | 4.19 | 5.61 | 5.53 | 6.12 | 1.34 | 1.93 |
| | OCT | 4.19 | 5.63 | 5.55 | 6.14 | 1.36 | 1.95 |
| | NOV | 4.31 | 5.68 | 5.63 | 6.17 | 1.32 | 1.86 |
| | DEC | 4.50 | 5.78 | 5.79 | 6.26 | 1.29 | 1.76 |
| 2010 | JAN | 4.60 | 5.76 | 5.77 | 6.16 | 1.17 | 1.55 |
| | FEB | 4.62 | 5.86 | 5.87 | 6.25 | 1.25 | 1.63 |
| | MAR | 4.65 | 5.81 | 5.84 | 6.22 | 1.20 | 1.58 |

Sources:
[1] Bloomberg, U.S. Government Generic 30-Year Treasury Bond
[2] Bloomberg, Moody's Corporate Average Bond Index
[3] Bloomberg, Moody's A-Rated Utility Bond Index
[4] Bloomberg, Moody's Baa-Rated Utility Bond Index
[5] Equals [3] - [1]
[6] Equals [4] - [1]

# Montana-Dakota Utilities Co.

## POPULATION IN NORTH DAKOTA COUNTIES WHERE MONTANA-DAKOTA PROVIDES ELECTRIC SERVICE 1990 TO 2009

| | | | | Population Change | |
|---|---|---|---|---|---|
| | 1990 | 2000 | 2009 | 2000-2009 | 1990-2009 |
| | | | Estimate | | |
| **North Dakota** | **638,800** | **642,200** | **646,844** | **0.72%** | **1.26%** |
| Counties Served by Montana-Dakota | | | | | |
| Adams | 3,174 | 2,593 | 2,236 | -13.77% | -29.55% |
| Bowman | 3,596 | 3,242 | 3,028 | -6.60% | -15.80% |
| Burke | 3,002 | 2,242 | 1,839 | -17.98% | -38.74% |
| Burleigh | 60,131 | 69,416 | 79,822 | 14.99% | 32.75% |
| Dickey | 6,107 | 5,757 | 5,217 | -9.38% | -14.57% |
| Divide | 2,899 | 2,283 | 1,961 | -14.10% | -32.36% |
| Dunn | 4,005 | 3,600 | 3,365 | -6.53% | -15.98% |
| Emmons | 4,830 | 4,331 | 3,398 | -21.54% | -29.65% |
| Golden Valley | 2,108 | 1,924 | 1,621 | -15.75% | -23.10% |
| Grant | 3,549 | 2,841 | 2,337 | -17.74% | -34.15% |
| Hettinger | 3,445 | 2,715 | 2,343 | -13.70% | -31.99% |
| Kidder | 3,332 | 2,753 | 2,201 | -20.05% | -33.94% |
| LaMoure | 5,383 | 4,701 | 3,908 | -16.87% | -27.40% |
| Logan | 2,847 | 2,308 | 1,886 | -18.28% | -33.75% |
| Mcintosh | 4,021 | 3,390 | 2,582 | -23.83% | -35.79% |
| McKenzie | 6,383 | 5,737 | 5,799 | 1.08% | -9.15% |
| Mercer | 9,808 | 8,644 | 5,799 | -32.91% | -40.87% |
| Morton | 23,700 | 25,303 | 26,464 | 4.59% | 11.66% |
| Mountrail | 7,021 | 6,631 | 6,791 | 2.41% | -3.28% |
| Oliver | 2,381 | 2,065 | 1,643 | -20.44% | -31.00% |
| Renville | 3,160 | 2,610 | 2,227 | -14.67% | -29.53% |
| Richland | 18,148 | 17,998 | 16,067 | -10.73% | -11.47% |
| Sioux | 3,761 | 4,044 | 4,203 | 3.93% | 11.75% |
| Slope | 907 | 767 | 649 | -15.38% | -28.45% |
| Stark | 22,832 | 22,636 | 22,847 | 0.93% | 0.07% |
| Ward | 57,921 | 58,795 | 57,012 | -3.03% | -1.57% |
| Williams - includes Williston | 21,129 | 19,761 | 20,451 | 3.49% | -3.21% |
| **Total MDU** | **289,580** | **289,087** | **287,696** | **-0.48%** | **-0.65%** |

| | 1990 | 2000 | 2009 Estimate | Population Change 2000-2009 | Population Change 1990-2009 |
|---|---|---|---|---|---|
| **Counties Not Served by Montana-Dakota** | | | | | |
| **Barnes** | 12,545 | 11,775 | 10,753 | -8.68% | -14.28% |
| **Benson** | 7,198 | 6,964 | 10,753 | 54.41% | 49.39% |
| **Billings** | 1,108 | 888 | 827 | -6.87% | -25.36% |
| **Bottineau** | 8,011 | 7,149 | 6,352 | -11.15% | -20.71% |
| **Cass** | 102,874 | 123,138 | 143,339 | 16.41% | 39.33% |
| **Cavalier** | 6,064 | 4,831 | 3,699 | -23.43% | -39.00% |
| **Eddy** | 2,951 | 2,757 | 2,288 | -17.01% | -22.47% |
| **Foster** | 3,983 | 3,759 | 3,259 | -13.30% | -18.18% |
| **Grand Forks** | 70,683 | 66,109 | 66,414 | 0.46% | -6.04% |
| **Griggs** | 3,303 | 2,754 | 2,346 | -14.81% | -28.97% |
| **Hettinger** | 3,445 | 2,715 | 2,343 | -13.70% | -31.99% |
| **McHenry** | 6,528 | 5,987 | 5,173 | -13.60% | -20.76% |
| **McLean** | 10,457 | 9,311 | 8,310 | -10.75% | -20.53% |
| **Nelson** | 4,410 | 3,715 | 3,129 | -15.77% | -29.05% |
| **Pembina** | 9,238 | 8,585 | 7,392 | -13.90% | -19.98% |
| **Pierce** | 5,052 | 4,675 | 3,990 | -14.65% | -21.02% |
| **Ramsey** | 12,681 | 12,066 | 11,240 | -6.85% | -11.36% |
| **Ransom** | 5,921 | 5,890 | 5,500 | -6.62% | -7.11% |
| **Rolette** | 12,772 | 13,674 | 13,797 | 0.90% | 8.03% |
| **Sargent** | 4,549 | 4,366 | 3,951 | -9.51% | -13.15% |
| **Sheridan** | 2,148 | 1,710 | 1,228 | -28.19% | -42.83% |
| **Steele** | 2,420 | 2,258 | 1,747 | -22.63% | -27.81% |
| **Stutsman** | 22,241 | 21,908 | 20,463 | -6.60% | -7.99% |
| **Towner** | 3,627 | 2,876 | 2,209 | -23.19% | -39.10% |
| **Traill** | 8,752 | 8,477 | 7,868 | -7.18% | -10.10% |
| **Walsh** | 13,840 | 12,389 | 10,798 | -12.84% | -21.98% |
| **Wells** | 5,864 | 5,102 | 4,092 | -19.80% | -30.22% |
| **Total Other Counties** | **352,665** | **355,828** | **363,260** | **2.09%** | **3.00%** |

SOURCE: U.S. BUREAU OF THE CENSUS. DECENNIAL CENSUSES OF POPULATION

# Montana-Dakota Utilities Co.

## Selected Electric Utility Proxy Companies
## Fiscal Year 2009 Operating Data

| | | Assets ($000,000) | Operating Revenues ($000,000) | Operating Income ($000,000) |
|---|---|---|---|---|
| American Electric Power Co., Inc. | AEP | $48,348 | $13,489 | $2,771 |
| Cleco Corp. | CNL | $3,695 | $854 | $107 |
| DPL Inc. | DPL | $3,642 | $1,589 | $428 |
| Empire District Electric Co. | EDE | $1,840 | $497 | $74 |
| Great Plains Energy Inc. | GXP | $8,483 | $1,965 | $320 |
| IDACORP, Inc. | IDA | $4,239 | $1,050 | $204 |
| Northeast Utilities | NU | $14,058 | $5,439 | $751 |
| Pinnacle West Capital Corp. | PNW | $11,808 | $3,297 | $322 |
| Portland General Electric Co. | POR | $5,172 | $1,804 | $208 |
| Progress Energy, Inc. | PGN | $31,236 | $9,885 | $1,772 |
| Southern Company | SO | $52,046 | $15,743 | $3,268 |
| Westar Energy, Inc. | WR | $7,525 | $1,858 | $355 |
| Xcel Energy Inc. | XEL | $25,488 | $9,644 | $1,469 |
| High | | $52,046 | $15,743 | $3,268 |
| Median | | **$8,483** | **$1,965** | **$355** |
| Low | | $1,840 | $497 | $74 |
| Montana-Dakota Electric Utility | | **$570** | **$196** | **$37** |
| MDU Resources Group, Inc. | MDU | $5,991 | $4,177 | $467 * |
| Montana-Dakota Electric Utility % of: | | | | |
| - Proxy Company Median | | **6.7%** | **10.0%** | **10.4%** |
| - MDU Resources Group, Inc. | | 9.5% | 4.7% | 7.9% |

Sources: 2009 10-Ks

* 2009 Operating Income excluding a $620 million write-down of the value of oil and gas assets.

# Montana-Dakota Utilities Co.

## Bond Ratings of
## Selected Electric Utility Proxy Companies

| | | Standard & Poor's | Moody's |
|---|---|---|---|
| American Electric Power Co., Inc. | AEP | BBB | -- |
| Cleco Corp. | CNL | BBB | Baa2 |
| DPL Inc. | DPL | A- | A2 |
| Empire District Electric Co. | EDE | BBB- | Baa2 |
| Great Plains Energy Inc. | GXP | BBB | Baa2 |
| IDACORP, Inc. | IDA | BBB | Baa2 |
| Northeast Utilities | NU | BBB | Baa2 |
| Pinnacle West Capital Corp. | PNW | BBB- | Baa3 |
| Portland General Electric Co. | POR | BBB | Baa2 |
| Progress Energy, Inc. | PGN | BBB+ | A3 |
| Southern Company | SO | A | -- |
| Westar Energy, Inc. | WR | BBB- | Baa3 |
| Xcel Energy Inc. | XEL | BBB+ | Baa1 |
| Median | | BBB | Baa2 |
| MDU Resources Group, Inc. | | BBB+ | Baa1 |

Source: Bloomberg & SNL

# Montana-Dakota Utilities Co.

## Selected Electric Utility Proxy Companies
## Dividend Yields
## October 2009 - March 2010

| | | Stock Price October 2009 - March 2010 | | | | |
|---|---|---|---|---|---|---|
| | | High | Low | Average | Dividend | Yield |
| American Electric Power Co., Inc. | AEP | $ 34.32 | $ 32.39 | $ 33.35 | $ 1.64 | 4.92% |
| Cleco Corp. | CNL | $ 26.73 | $ 25.08 | $ 25.91 | $ 0.90 | 3.47% |
| DPL Inc. | DPL | $ 27.73 | $ 26.43 | $ 27.08 | $ 1.16 | 4.30% |
| Empire District Electric Co. | EDE | $ 18.81 | $ 18.10 | $ 18.45 | $ 1.28 | 6.94% |
| Great Plains Energy Inc. | GXP | $ 18.97 | $ 17.54 | $ 18.26 | $ 0.83 | 4.55% |
| IDACORP, Inc. | IDA | $ 32.45 | $ 30.22 | $ 31.34 | $ 1.20 | 3.83% |
| Northeast Utilities | NU | $ 25.95 | $ 24.32 | $ 25.13 | $ 0.98 | 3.88% |
| Pinnacle West Capital Corp. | PNW | $ 36.86 | $ 34.25 | $ 35.55 | $ 2.10 | 5.91% |
| Portland General Electric Co. | POR | $ 20.19 | $ 18.79 | $ 19.49 | $ 1.02 | 5.23% |
| Progress Energy, Inc. | PGN | $ 40.11 | $ 38.05 | $ 39.08 | $ 2.48 | 6.35% |
| Southern Company | SO | $ 33.22 | $ 31.62 | $ 32.42 | $ 1.75 | 5.40% |
| Westar Energy, Inc. | WR | $ 21.77 | $ 20.44 | $ 21.10 | $ 1.21 | 5.72% |
| Xcel Energy Inc. | XEL | $ 21.08 | $ 19.99 | $ 20.53 | $ 0.98 | 4.77% |
| Average | | | | | | 5.02% |

Source: Bloomberg

# Montana-Dakota Utilities Co.

## Projected Earnings Retention Growth Rates for Selected Electric Utility Proxy Companies

| | | Value Line Forecast 2013-2015 | | | | |
|---|---|---|---|---|---|---|
| | | EPS | DPS | ROE | Retention Rate | Retention Growth |
| American Electric Power Co., Inc. | AEP | $ 3.50 | $ 1.90 | 10.00% | 45.71% | 4.57% |
| Cleco Corp. | CNL | $ 2.50 | $ 1.40 | 11.00% | 44.00% | 4.84% |
| DPL Inc. | DPL | $ 2.90 | $ 1.50 | 28.00% | 48.28% | 13.52% |
| Empire District Electric Co. | EDE | $ 1.75 | $ 1.35 | 10.00% | 22.86% | 2.29% |
| Great Plains Energy Inc. | GXP | $ 1.75 | $ 1.20 | 8.00% | 31.43% | 2.51% |
| IDACORP, Inc. | IDA | $ 2.75 | $ 1.40 | 7.50% | 49.09% | 3.68% |
| Northeast Utilities | NU | $ 2.25 | $ 1.25 | 9.00% | 44.44% | 4.00% |
| Pinnacle West Capital Corp. | PNW | $ 3.25 | $ 2.20 | 9.00% | 32.31% | 2.91% |
| Portland General Electric Co. | POR | $ 2.00 | $ 1.20 | 8.50% | 40.00% | 3.40% |
| Progress Energy, Inc. | PGN | $ 3.55 | $ 2.58 | 9.00% | 27.32% | 2.46% |
| Southern Company | SO | $ 3.00 | $ 2.10 | 13.00% | 30.00% | 3.90% |
| Westar Energy, Inc. | WR | $ 2.25 | $ 1.40 | 8.50% | 37.78% | 3.21% |
| Xcel Energy Inc. | XEL | $ 2.00 | $ 1.10 | 10.50% | 45.00% | 4.73% |
| Average | | | | | | 4.31% |

# Montana-Dakota Utilities Co.

## Second-Stage Retention Growth Rate Estimates for Selected Electric Utility Proxy Companies

| | | 2/3 Zacks 5-Yr Earnings Growth Est. | 1/3 Retention Growth | Weighted Average |
|---|---|---|---|---|
| American Electric Power Co., Inc. | AEP | 3.60% | 4.57% | 3.92% |
| Cleco Corp. | CNL | 9.00% | 4.84% | 7.61% |
| DPL Inc. | DPL | 5.00% | 13.52% | 7.84% |
| Empire District Electric Co. (1) | EDE | 6.00% | 2.29% | 4.76% |
| Great Plains Energy Inc. | GXP | 5.00% | 2.51% | 4.17% |
| IDACORP, Inc. | IDA | 5.00% | 3.68% | 4.56% |
| Northeast Utilities | NU | 7.90% | 4.00% | 6.60% |
| Pinnacle West Capital Corp. | PNW | 7.00% | 2.91% | 5.64% |
| Portland General Electric Co. | POR | 5.80% | 3.40% | 5.00% |
| Progress Energy, Inc. | PGN | 4.00% | 2.46% | 3.49% |
| Southern Company | SO | 7.10% | 3.90% | 6.03% |
| Westar Energy, Inc. | WR | 5.00% | 3.21% | 4.40% |
| Xcel Energy Inc. | XEL | 5.70% | 4.73% | 5.38% |
| Average | | 5.85% | 4.31% | 5.34% |
| Median | | 5.70% | 3.68% | 5.00% |

Source: Zacks.com and page 4.

(1) Because there was no published Zacks growth rate for this company, a Yahoo! First Call growth rate was substituted in its place.

# Montana-Dakota Utilities Co.

## Second-Stage Retention Growth DCF Calculation for Selected Electric Utility Proxy Companies

| | | Dividend Yield | Dividend Yield Times (1 + .625g) | Expected Growth Rate (g) | Secondary Market: Investor Required Return | Flotation Cost Adjustment | Primary Market: Cost of Capital |
|---|---|---|---|---|---|---|---|
| American Electric Power Co., Inc. | AEP | 4.92% | 5.04% | 3.92% | 8.96% | 1.036 | 9.29% |
| Cleco Corp. | CNL | 3.47% | 3.64% | 7.61% | 11.25% | 1.036 | 11.66% |
| DPL Inc. | DPL | 4.30% | 4.51% | 7.84% | 12.35% | 1.036 | 12.79% |
| Empire District Electric Co. | EDE | 6.94% | 7.14% | 4.76% | 11.90% | 1.036 | 12.34% |
| Great Plains Energy Inc. | GXP | 4.55% | 4.66% | 4.17% | 8.84% | 1.036 | 9.16% |
| IDACORP, Inc. | IDA | 3.83% | 3.94% | 4.56% | 8.50% | 1.036 | 8.81% |
| Northeast Utilities | NU | 3.88% | 4.04% | 6.60% | 10.64% | 1.036 | 11.03% |
| Pinnacle West Capital Corp. | PNW | 5.91% | 6.11% | 5.64% | 11.75% | 1.036 | 12.18% |
| Portland General Electric Co. | POR | 5.23% | 5.40% | 5.00% | 10.40% | 1.036 | 10.77% |
| Progress Energy, Inc. | PGN | 6.35% | 6.48% | 3.49% | 9.97% | 1.036 | 10.33% |
| Southern Company | SO | 5.40% | 5.60% | 6.03% | 11.63% | 1.036 | 12.06% |
| Westar Energy, Inc. | WR | 5.72% | 5.88% | 4.40% | 10.28% | 1.036 | 10.65% |
| Xcel Energy Inc. | XEL | 4.77% | 4.93% | 5.38% | 10.31% | 1.036 | 10.68% |
| **High** | | | | | 12.35% | | **12.79%** |
| | | **3rd Quartile** | | | 11.63% | | **12.06%** |
| **Median** | | **2nd Quartile** | | | 10.40% | | **10.77%** |
| | | **1st Quartile** | | | 9.97% | | **10.33%** |
| **Low** | | | | | 8.50% | | **8.81%** |
| **Average** | | | | | 10.52% | | **10.90%** |

# Montana-Dakota Utilities Co.

## Basic DCF Calculation
## for Selected Electric Utility Proxy Companies

| | | Dividend Yield | Dividend Yield Times (1 + .625g) | Expected Growth Rate (g) | Secondary Market: Investor Required Return | Flotation Cost Adjustment | Primary Market: Cost of Capital |
|---|---|---|---|---|---|---|---|
| American Electric Power Co., Inc. | AEP | 4.92% | 5.03% | 3.60% | 8.63% | 1.036 | 8.94% |
| Cleco Corp. | CNL | 3.47% | 3.67% | 9.00% | 12.67% | 1.036 | 13.13% |
| DPL Inc. | DPL | 4.30% | 4.43% | 5.00% | 9.43% | 1.036 | 9.77% |
| Empire District Electric Co. | EDE | 6.94% | 7.20% | 6.00% | 13.20% | 1.036 | 13.68% |
| Great Plains Energy Inc. | GXP | 4.55% | 4.69% | 5.00% | 9.69% | 1.036 | 10.04% |
| IDACORP, Inc. | IDA | 3.83% | 3.95% | 5.00% | 8.95% | 1.036 | 9.27% |
| Northeast Utilities | NU | 3.88% | 4.07% | 7.90% | 11.97% | 1.036 | 12.41% |
| Pinnacle West Capital Corp. | PNW | 5.91% | 6.16% | 7.00% | 13.16% | 1.036 | 13.64% |
| Portland General Electric Co. | POR | 5.23% | 5.42% | 5.80% | 11.22% | 1.036 | 11.63% |
| Progress Energy, Inc. | PGN | 6.35% | 6.51% | 4.00% | 10.51% | 1.036 | 10.89% |
| Southern Company | SO | 5.40% | 5.64% | 7.10% | 12.74% | 1.036 | 13.20% |
| Westar Energy, Inc. | WR | 5.72% | 5.90% | 5.00% | 10.90% | 1.036 | 11.29% |
| Xcel Energy Inc. | XEL | 4.77% | 4.94% | 5.70% | 10.64% | 1.036 | 11.03% |
| **High** | | | | | 13.20% | | **13.68%** |
| | | **3rd Quartile** | | | 12.67% | | **13.13%** |
| **Median** | | **2nd Quartile** | | | 10.90% | | **11.29%** |
| | | **1st Quartile** | | | 9.69% | | **10.04%** |
| **Low** | | | | | 8.63% | | **8.94%** |
| **Average** | | | | | 11.05% | | **11.46%** |

## Montana-Dakota Utilities Co.

### Selected Electric Utility Proxy Companies
### Capital Structures as of December 31, 2009

| | | Short-Term Debt (Millions) | % | Long-Term Debt (Millions) | % | Preferred Stock (Millions) | % | Common Equity (Millions) | % | Total Capital |
|---|---|---|---|---|---|---|---|---|---|---|
| American Electric Power Co., Inc. | AEP | $ 126.0 | 0.41% | $ 17,498.0 | 56.77% | $ 61.0 | 0.20% | $ 13,140.0 | 42.63% | $ 30,825.0 |
| Cleco Corp. | CNL | $ - | 0.00% | $ 1,331.8 | 54.41% | $ 1.0 | 0.04% | $ 1,115.0 | 45.55% | $ 2,447.8 |
| DPL Inc. | DPL | $ - | 0.00% | $ 1,324.1 | 54.11% | $ 22.9 | 0.94% | $ 1,099.9 | 44.95% | $ 2,446.9 |
| Empire District Electric Co. | EDE | $ 50.5 | 3.76% | $ 691.2 | 51.51% | $ - | 0.00% | $ 600.2 | 44.73% | $ 1,341.8 |
| Great Plains Energy Inc. | GXP | $ 438.6 | 6.76% | $ 3,214.3 | 49.56% | $ 39.0 | 0.60% | $ 2,793.7 | 43.08% | $ 6,485.6 |
| IDACORP, Inc. | IDA | $ 53.8 | 1.87% | $ 1,419.1 | 49.37% | $ - | 0.00% | $ 1,401.5 | 48.76% | $ 2,874.4 |
| Northeast Utilities | NU | $ 100.3 | 1.14% | $ 5,001.7 | 56.86% | $ 116.2 | 1.32% | $ 3,577.9 | 40.68% | $ 8,796.1 |
| Pinnacle West Capital Corp. | PNW | $ 153.7 | 2.15% | $ 3,648.2 | 51.04% | $ - | 0.00% | $ 3,345.7 | 46.81% | $ 7,147.6 |
| Portland General Electric Co. | POR | $ - | 0.00% | $ 1,744.0 | 53.06% | $ - | 0.00% | $ 1,543.0 | 46.94% | $ 3,287.0 |
| Progress Energy, Inc. | PGN | $ 140.0 | 0.63% | $ 12,678.0 | 56.68% | $ 93.0 | 0.42% | $ 9,455.0 | 42.27% | $ 22,366.0 |
| Southern Company | SO | $ 639.0 | 1.78% | $ 19,244.0 | 53.69% | $ 1,082.0 | 3.02% | $ 14,878.0 | 41.51% | $ 35,843.0 |
| Westar Energy, Inc. | WR | $ 242.8 | 4.75% | $ 2,601.4 | 50.86% | $ 21.4 | 0.42% | $ 2,248.8 | 43.97% | $ 5,114.4 |
| Xcel Energy Inc. | XEL | $ 459.0 | 2.82% | $ 8,432.4 | 51.80% | $ 105.0 | 0.64% | $ 7,283.2 | 44.74% | $ 16,279.7 |
| **Median** | | | **1.78%** | | **53.06%** | | **0.42%** | | **44.73%** | |

Source: 2009 10-Ks

# Montana-Dakota Utilities Co.

## Flotation Costs Associated With Electric Company Common Stock Issues 2000 - 2009

| Company | Ticker | Year | Month | Day | Number of Shares (000's) | Price to Public | Net Proceeds | Issue Cost as a Percent of Net Proceeds |
|---|---|---|---|---|---|---|---|---|
| Consolidated Edison, Inc. | ED | 2009 | NOV | 30 | 5,000 | $42.630 | $42.250 | 0.90% |
| Ameren Corp. | AEE | 2009 | SEP | 9 | 19,000 | $25.250 | $24.469 | 3.19% |
| CenterPoint Energy, Inc. | CNP | 2009 | SEP | 9 | 21,000 | $12.000 | $11.564 | 3.77% |
| UIL Holdings Corp | UIL | 2009 | MAY | 20 | 4,000 | $21.000 | $19.869 | 5.69% |
| Unitil Corp | UTL | 2009 | MAY | 20 | 2,400 | $20.000 | $18.742 | 6.71% |
| Great Plains Energy Inc | GXP | 2009 | MAY | 12 | 10,000 | $14.000 | $13.460 | 4.01% |
| American Electric Power Co Inc | AEP | 2009 | APR | 1 | 60,000 | $24.500 | $23.758 | 3.12% |
| Northeast Utilities | NU | 2009 | MAR | 16 | 16,500 | $20.200 | $19.523 | 3.47% |
| Portland General Electric Co | POR | 2009 | MAR | 5 | 10,850 | $14.100 | $13.571 | 3.89% |
| Progress Energy Inc | PGN | 2009 | JAN | 7 | 12,500 | $37.500 | $36.351 | 3.16% |
| SCANA Corp | SCG | 2008 | DEC | 31 | 2,500 | $35.500 | $34.827 | 1.93% |
| Unitil Corp | UTL | 2008 | DEC | 11 | 2,000 | $20.000 | $18.950 | 5.54% |
| Hawaiian Electric Industries Inc | HE | 2008 | DEC | 3 | 5,000 | $23.000 | $22.077 | 4.18% |
| Central Vermont Public Service Corp | CV | 2008 | NOV | 18 | 1,190 | $19.000 | $17.677 | 7.48% |
| Pepco Holdings Inc | POM | 2008 | NOV | 5 | 14,000 | $16.500 | $15.867 | 3.99% |
| Otter Tail Corp | OTTR | 2008 | OCT | 18 | 4,500 | $30.000 | $28.823 | 4.08% |
| Xcel Energy Inc | XEL | 2008 | OCT | 9 | 15,000 | $20.200 | $20.060 | 0.70% |
| Westar Energy Inc | WR | 2008 | MAY | 29 | 6,000 | $24.280 | $23.376 | 3.87% |
| ITC Holdings Corp | ITC | 2008 | JAN | 17 | 5,583 | $50.150 | $47.858 | 4.79% |
| Energy East | EAS | 2007 | MAR | 21 | 9,000 | $24.250 | $23.504 | 3.18% |
| Empire Distric Electric Co. | EDE | 2007 | DEC | 6 | 3,000 | $23.000 | $21.920 | 4.93% |
| Empire District Electric Co. | EDE | 2006 | JUN | 15 | 3,200 | $20.250 | $19.312 | 4.86% |
| CLECO Corp. | CNL | 2006 | AUG | 14 | 6,000 | $23.750 | $22.860 | 3.89% |
| Avista Corp. | AVA | 2006 | DEC | 12 | 2,750 | $25.050 | $24.461 | 2.41% |
| Cinergy | CIN | 2005 | JAN | 28 | 3,399 | $50.000 | $48.279 | 3.56% |
| Cinergy | CIN | 2005 | FEB | 11 | 849 | $50.000 | $47.617 | 5.01% |
| CMS | CMS | 2005 | MAR | 30 | 20,000 | $12.250 | $11.809 | 3.73% |
| Pinnacle West | PNW | 2005 | APR | 27 | 5,300 | $42.000 | $40.588 | 3.48% |
| Puget Energy | PSD | 2005 | NOV | 1 | 15,000 | $20.800 | $20.650 | 0.73% |
| WPS Resources Corp | TEG | 2005 | NOV | 27 | 1,900 | $53.700 | $51.955 | 3.36% |
| Northeast Utilities | NU | 2005 | DEC | 12 | 20,000 | $19.090 | $18.453 | 3.45% |
| Hawaiian Electric Industries | HE | 2004 | MAR | 10 | 2,000 | $51.860 | $49.711 | 4.32% |
| Consolidated Edison, Inc. | ED | 2004 | APR | 11 | 14,000 | $37.750 | $36.589 | 3.17% |
| Great Plains Energy Corp | GXP | 2004 | JUN | 8 | 5,000 | $30.000 | $28.880 | 3.88% |
| Great Plains Energy Corp | GXP | 2004 | JUN | 8 | 6,000 | $25.000 | $24.167 | 3.45% |
| Constellation Energy | CEG | 2004 | JUN | 28 | 6,000 | $37.950 | $37.768 | 0.48% |
| CMS Energy | CMS | 2004 | OCT | 7 | 28,500 | $9.100 | $8.770 | 3.76% |
| Ottertail Corporation | OTTR | 2004 | DEC | 7 | 2,900 | $25.450 | $24.397 | 4.32% |
| IDACORP | IDA | 2004 | DEC | 9 | 83,500 | $30.000 | $28.796 | 4.18% |
| Ameren Corp. | AEE | 2003 | JAN | 14 | 5,500 | $40.500 | $39.107 | 3.56% |
| Cinergy | CIN | 2003 | JAN | 31 | 5,700 | $31.100 | $30.815 | 0.93% |
| American Electric Power Co. | AEP | 2003 | FEB | 27 | 50,000 | $20.950 | $20.311 | 3.15% |
| PPL Corp | PPL | 2003 | MAY | 15 | 65,000 | $38.250 | $37.001 | 3.38% |
| Consolidated Edison Inc | ED | 2003 | MAY | 19 | 87,000 | $39.800 | $39.451 | 0.88% |
| OGE Energy Corp | OGE | 2003 | AUG | 21 | 4,650 | $21.600 | $20.810 | 3.80% |
| FirstEnergy Corp | FE | 2003 | SEP | 12 | 28,000 | $30.000 | $29.010 | 3.41% |
| PSEG | PEG | 2003 | OCT | 1 | 8,250 | $41.750 | $40.455 | 3.20% |
| UNITIL | UTL | 2003 | OCT | 23 | 6,524 | $25.400 | $24.130 | 5.26% |

| Company | Ticker | Year | Month | Day | Number of Shares (000's) | Price to Public | Net Proceeds | a Percent of Net Proceeds |
|---|---|---|---|---|---|---|---|---|
| Puget Energy | PSD | 2003 | OCT | 31 | 4,550 | $22.750 | $22.000 | 3.41% |
| WPS Resources Corp | TEG | 2003 | NOV | 19 | 3,500 | $43.000 | $42.202 | 1.89% |
| Empire District Electric Co. | EDE | 2003 | DEC | 11 | 2,000 | $21.150 | $20.138 | 5.03% |
| TXU Corp | TXU | 2002 | NOV | 25 | 30,500 | $14.770 | $14.278 | 3.45% |
| Great Plains Energy Inc | GXP | 2002 | NOV | 21 | 6,000 | $22.000 | $21.175 | 3.90% |
| PSE&G | PEG | 2002 | NOV | 12 | 15000 | $26.550 | $25.664 | 3.45% |
| Progress Energy, Inc | PGN | 2002 | NOV | 6 | 14,670 | $41.900 | $40.857 | 2.55% |
| Puget Energy | PSD | 2002 | NOV | 5 | 5000 | $20.700 | $19.975 | 3.63% |
| Puget Energy | PSD | 2002 | OCT | 31 | 5,000 | $20.700 | $19.975 | 3.63% |
| TECO Energy, Inc | TE | 2002 | OCT | 10 | 17,000 | $11.000 | $10.659 | 3.20% |
| Duke Energy | DUK | 2002 | SEP | 25 | 54,500 | $18.350 | $17.873 | 2.67% |
| PPL Corp | PPL | 2002 | SEP | 12 | 14,500 | $30.500 | $29.505 | 3.37% |
| Ameren Corp. | AEE | 2002 | SEP | 10 | 7,000 | $42.000 | $40.573 | 3.52% |
| DQE | DQE | 2002 | JUN | 20 | 15,000 | $13.500 | $12.961 | 4.16% |
| DTE Energy | DTE | 2002 | JUN | 19 | 5,500 | $43.250 | $41.799 | 3.47% |
| FPL Group | FPL | 2002 | JUN | 6 | 5,000 | $56.600 | $54.850 | 3.19% |
| FPL Group (F) | FPL | 2002 | JUN | 6 | 8,800 | $50.000 | $48.415 | 3.27% |
| American Electric Power Co. | AEP | 2002 | JUN | 5 | 16,000 | $40.900 | $39.650 | 3.15% |
| TECO Energy, Inc | TE | 2002 | JUN | 4 | 13,500 | $23.000 | $22.310 | 3.09% |
| TXU Corp | TXU | 2002 | MAY | 31 | 11,000 | $51.150 | $49.595 | 3.14% |
| Empire District Electric Co. | EDE | 2002 | MAY | 16 | 2,500 | $20.750 | $19.868 | 4.44% |
| Cleco Corp | CNL | 2002 | MAY | 2 | 1,750 | $33.000 | $32.036 | 3.01% |
| Xcel Energy Co. | XEL | 2002 | FEB | 28 | 20,000 | $22.500 | $21.755 | 3.42% |
| FPL Group | FPL | 2002 | JAN | 29 | 10,000 | $50.000 | $48.425 | 3.25% |
| Empire District Electric | EDE | 2001 | DEC | 4 | 1,750 | $20.370 | $19.500 | 4.46% |
| Hawaiian Electric Industries | HE | 2001 | NOV | 19 | 1,500 | $37.700 | $36.190 | 4.17% |
| Alliant Energy Corp | LNT | 2001 | NOV | 15 | 8,500 | $28.000 | $26.900 | 4.09% |
| Sierra Pacific | NVE | 2001 | AUG | 15 | 20,500 | $15.000 | $14.418 | 4.04% |
| Progressive Energy | PGN | 2001 | AUG | 14 | 11,000 | $40.000 | $38.600 | 3.63% |
| WPS Resource Corp | TEG | 2001 | MAY | 2 | 2,000 | $34.360 | $33.160 | 3.62% |
| Reliant Resources, Inc | RRI | 2001 | APR | 30 | 52,000 | $30.000 | $28.500 | 5.26% |
| Aquila, Inc | | 2001 | APR | 27 | 12,250 | $24.000 | $22.620 | 6.10% |
| Utilicorp United Inc | | 2001 | APR | 27 | 5,250 | $24.000 | $22.620 | 6.10% |
| Allegheny Energy Inc | AYE | 2001 | APR | 26 | 12,400 | $48.250 | $46.800 | 3.10% |
| Black Hills Corporation | BKH | 2001 | APR | 18 | 3,000 | $52.000 | $49.140 | 5.82% |
| Constellation Energy | CEG | 2001 | MAR | 21 | 12,000 | $39.900 | $39.280 | 1.58% |
| Duke Energy | DUK | 2001 | MAR | 13 | 25,000 | $38.980 | $37.947 | 2.72% |
| Utilicorp United Inc | | 2001 | MAR | 9 | 10,000 | $29.760 | $28.940 | 2.83% |
| TECO Energy, Inc | TE | 2001 | MAR | 6 | 7,500 | $27.750 | $26.883 | 3.22% |
| CMS Energy | CMS | 2001 | FEB | 23 | 10,000 | $29.750 | $29.560 | 0.64% |
| Allete | ALE | 2001 | JAN | 24 | 6,500 | $23.680 | $22.679 | 4.41% |
| CMS Energy | CMS | 2000 | OCT | 16 | 11,000 | $18.250 | $17.770 | 2.70% |
| TNPC | | 2000 | OCT | 4 | 24,000 | $21.000 | $19.790 | 6.11% |
| NRG Energy Inc. | NRG | 2000 | MAY | 30 | 28,170 | $15.000 | $14.100 | 6.38% |
| Southern Company | SO | 2000 | DEC | 7 | 25,000 | $28.500 | $27.560 | 3.41% |
| **AVERAGE** | | | | | | | | 3.63% |

Source: Public Utility Finance Tracker through 2007; Bloomberg data from 2008 to present.

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| MDU Resources Group | 2002 | NOV | 29 | 2,100 | $ 24.000 | 23.188 | 3.50% |
| MDU Resources Group | 2002 | NOV | 19 | 2,100 | $ 24.000 | 23.280 | 3.09% |