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

Before the North Dakota Public Service Commission

Case No. PU-17-___

Direct Testimony
of
Nicole A. Kivisto

Q. Please state your name and business address.

A. Yes. My name is Nicole A. Kivisto, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the President and Chief Executive Officer (CEO) for Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Co., Divisions of MDU Resources Group, Inc. I am also the President and CEO of Cascade Natural Gas Corporation and Intermountain Gas Company; subsidiaries of MDU Resources Group, Inc.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission, the Public Service Commissions of Montana and Wyoming, the Public Utilities Commissions of Minnesota and South Dakota, the

Public Utility Commissions of Oregon and Idaho, and the Washington Utilities and Transportation Commission.

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I have executive responsibility for the development, coordination, and implementation of strategies and policies relative to operations of the above mentioned companies that, in combination, serve over one million customers in eight states.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Accounting from Minnesota State University Moorhead. I have worked for MDU Resources/Montana-Dakota for twenty two years and have been in my current capacity since January 2015. I was the Vice President - Operations of Montana-Dakota and Great Plains Natural Gas Co., Divisions of MDU Resources Group, Inc. from January of 2014 until assuming my present position.

Prior to that, I was the Vice President, Controller and Chief Accounting Officer for MDU Resources for nearly four years, and held other finance related positions prior to that.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of Montana-Dakota's gas operations. I will also provide an overview of the Company's request for a natural gas distribution rate increase, discuss the reasons underlying the major aspects of the request and introduce the Company's proposed System Safety Integrity Program (SSIP) and the proposed adjustment mechanism required to fund the SSIP. Finally, I will address the need for an interim increase and introduce the other Company witnesses that will present testimony and exhibits in further support of the Company's request.

Q. Would you provide a summary of Montana-Dakota's gas operations in North Dakota?

A. Montana-Dakota provides natural gas service to approximately 109,000 customers in 74 communities in North Dakota, operating approximately 2,575 miles of distribution mains and approximately 110,000 service lines. The customer base is 86 percent residential customers and 14 percent commercial and industrial customers. As of December 31, 2016, the Company had 562 full and part time employees who live and work throughout the Company's North Dakota electric and gas service area. Montana-Dakota's North Dakota gas service area is divided into two operating regions with regional offices located in Bismarck and Dickinson, North Dakota. In addition to the regional offices, there are fully staffed operations centers located in the communities of Minot, Williston, and Devils Lake, with satellite offices in Watford City and Jamestown.

Mr. Patrick Darras will provide additional information regarding the distribution system in North Dakota and the structure of the Distribution Operations group and describe how that group operates and maintains the distribution system to ensure the safety of customers and compliance with all pipeline safety regulations.

Montana-Dakota's customers have toll-free access to the Customer Service Centers located in Meridian, Idaho and Bismarck, North Dakota as well as the Credit Center in Bismarck, North Dakota, to place routine utility service requests and inquiries from 7:00 am to 7:00 pm local time, Monday through Friday and emergency calls on a 24-hour basis. A scheduling center, located in Meridian, Idaho transmits electronic service orders to the mobile terminals placed in our fleet of service and construction vehicles. This network allows the Company to respond quickly to customer requests and emergency situations.

Q. Would you please provide more information regarding the customers the Company serves?

A. Yes. The residential, firm general service, and small interruptible customers use natural gas primarily for space and water heating. As such, Montana-Dakota's system has a low load factor with peak gas requirements occurring during the winter. Summer loads are small by comparison. Montana-Dakota is projecting to deliver approximately 23.4 Mmdk of natural gas to customers in North Dakota in 2018. The natural gas requirements by customer class is as follows: approximately 38 percent residential, 34 percent firm general service, 7 percent small interruptible, 19 percent large interruptible, and 2 percent for the Air Force.

Q. Would you please describe the basic elements that make up the total costs of providing natural gas service?

A. For a natural gas distribution utility, the basic elements which make up the cost of providing natural gas service are the cost of gas delivered at the town border stations in its service territory and the cost of distributing the gas from the town border station to the end use customer. It is the second of these two elements, the distribution costs, which are the subject of this application for a general rate increase.

The natural gas the Company purchases from suppliers is a commodity like wheat or corn, the price of which is not regulated. The cost of delivering the gas to the Company's distribution system at the town border station is regulated by the FERC or other regulatory agencies. These gas costs are passed on to customers on a dollar-for-dollar basis as specified in the Commission approved Cost of Gas tariff. The gas cost portion of the cost of providing natural gas service currently comprises about 61 percent of a typical residential bill for gas service.

The distribution portion of the Company's cost of service is the subject of this proceeding. This element includes the costs of new distribution investments, replacement of aging infrastructure, operation and maintenance expenses, depreciation, taxes, and the opportunity to earn a return on the Company's investments in facilities that provide natural gas service. Distribution costs are currently about 39 percent of a typical residential bill.

Q. Ms. Kivisto, did you authorize the filing of the rate application in this proceeding?

A. Yes, I did.

Q. What is the amount of the increase requested?

A. As will be fully explained by other Company witnesses, the Company is requesting a natural gas rate increase of $5,868,389 (a 5.4 percent increase over current rates) based on a projected 2018 test period.

Q. Why has Montana-Dakota filed this application for a natural gas rate increase?

A. Montana-Dakota is requesting an increase in its general gas rates at this time because the current rates do not reflect the cost of providing natural gas service to the Company's North Dakota customers.

Q. When was the Company's last general rate case?

A. The Company's last rate case was Case No. PU-15-090. The resulting rate increase was $2.6 million, or a 1.96 percent overall increase. Final rates in that case became effective on December 1, 2015.

Q. What are the primary reasons that Montana-Dakota needs an increase at this time?

A. The primary reasons for the need for an increase in rates is the increased investment in distribution facilities to improve system safety and reliability and the depreciation and taxes associated with the increase in investment. The increase in investment since the last rate case is attributable to mains, services and meters placed into service since the Company's last case and the Company's plan to address infrastructure integrity initiatives through a System Safety and Integrity Program. Without an increase in distribution rates, the Company projects its 2018 rate of return will be 4.850 percent, well below its cost of capital.

Q. Would you please describe the proposed System Safety and Integrity Program (SSIP)?

A. Yes. The Company is proposing a structured replacement program for Early Vintage Steel Pipe, Early Vintage Plastic Pipe, Low Pressure Systems and the relocation of inside meters. The SSIP will focus on the replacement of systems in these categories that are known for higher risks as identified by the Company's Distribution Integrity Management Plan (DIMP).

Q. What has prompted Montana-Dakota to propose the SSIP?

A. On March 28, 2011, following fatal explosions by natural gas pipeline failures in Allentown, Pennsylvania and San Bruno, California, United States Secretary of Transportation, Ray LaHood, issued a Call to Action. This Call to Action sought to engage state regulators, technical experts, and pipeline operators in identifying pipeline risks and repairing, rehabilitating and replacing the highest risk infrastructure. In addition, it called on pipeline operators and owners to evaluate the condition of their pipelines and quickly repair or replace sections in poor condition. In recent years, a number of states have approved programs addressing cost recovery mechanisms for distribution companies with programs addressing aging infrastructure on a more structured basis similar to Montana-Dakota's proposed SSIP. A study published by the American Gas Association indicates that, as of December 2016, 36 states have a cost recovery mechanism in place, similar to Montana-Dakota's proposed SSIP recovery mechanism, that allows utilities to address aging infrastructure while minimizing the frequency of rate cases necessary to recover the associated costs.

Company witness Patrick Darras will describe in his testimony the efforts that Montana-Dakota has undertaken to ensure a safe and reliable distribution system and will discuss in detail the proposed SSIP.

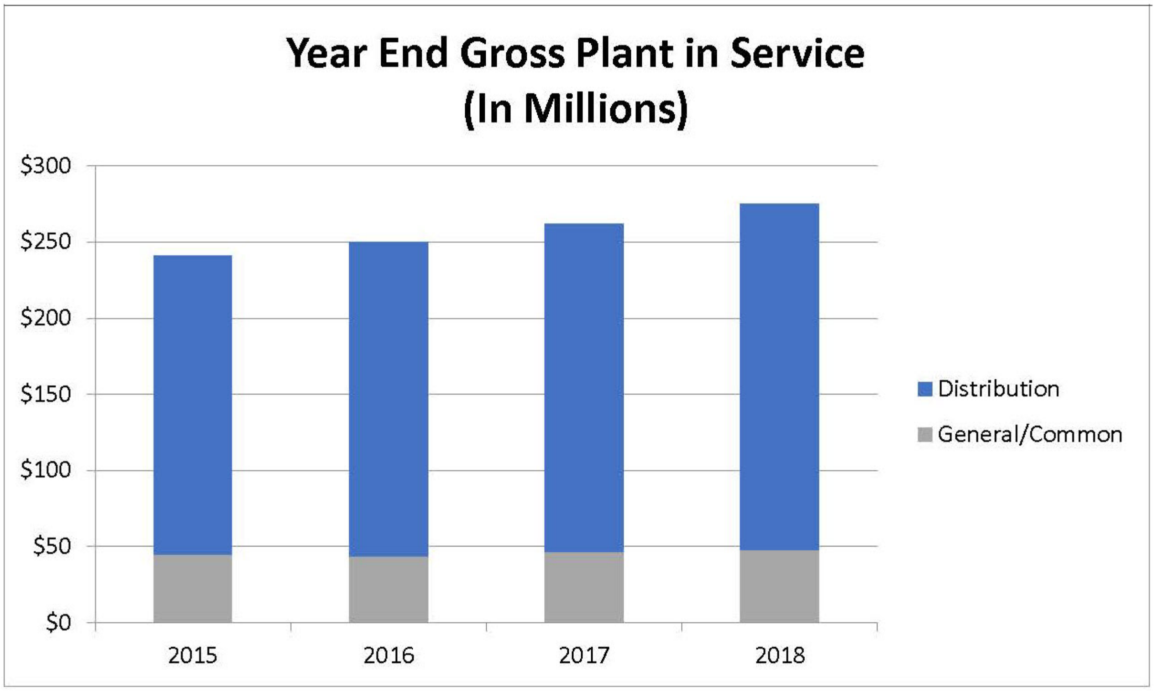
Q. What is the estimated cost of the SSIP under the adjustment mechanism in 2019?

A. Based on the projected investment in 2019 of approximately $6 million as identified by Mr. Darras, an annual revenue of approximately

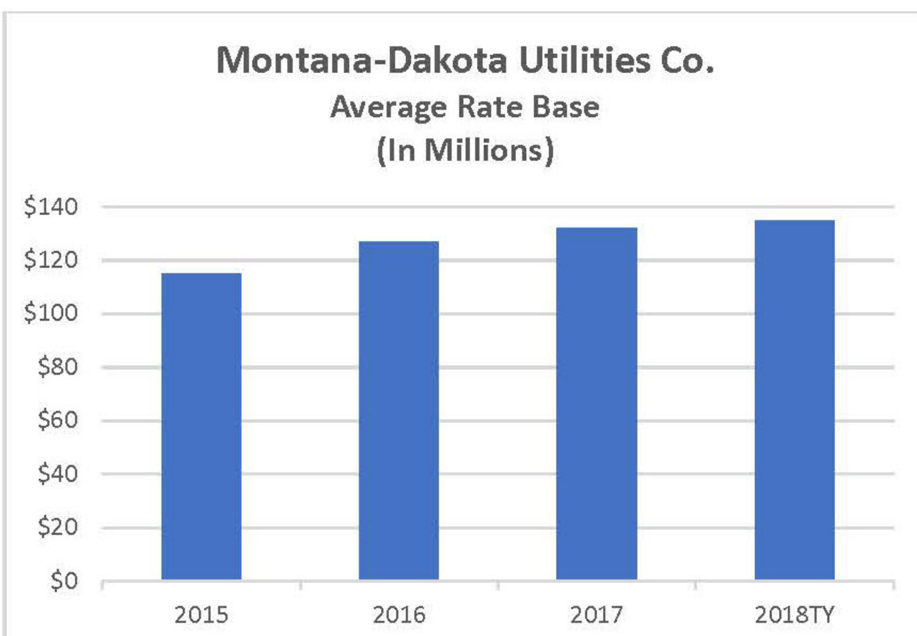
$860,000 would be required in 2019. This represents a monthly charge to residential customers of approximately $0.46 in order to enhance system safety and reliability. The proposed System Safety and Integrity Program Adjustment Mechanism provides a mechanism that allows the Company to proactively address pipeline integrity while potentially avoiding costly rate cases and providing customers with more gradual rate increases over time.

Q. How much has the gross investment and rate base increased since the last case?

A. The table below shows the year end gross investment in natural gas plant assigned and allocated to North Dakota gas operations. The year end gross investment projected for 2018 is $275 million or nearly 18 percent greater than the gross investment from the 2015 test year used in the last rate case. The chart below illustrates the increase in investment since 2015, with the average rate base increasing to approximately $135 million for the test period in this case.



The chart below illustrates the increase in investment since 2015, with the average base increasing to approximately $135 million for the test period in this case.



Q. Have increased operating expenses contributed to the need for this rate increase?

A. Yes, the Company's operating expenses, which include depreciation and taxes other than income, have increased since the last rate case. However, as mentioned earlier, the largest contributing factor has been the investment necessary to safely and adequately serve customers. Operation & Maintenance Expenses (O&M) have increased approximately 3 percent per year and have remained fairly consistent on a per customer basis since the last rate case.

Q. How will the requested increase affect the various classes of customers?

A. The proposed percentage change in rates by customer class is as follows:

Class	Percent Increase
Residential	5.9%
Firm General	5.5%
Air Force Delivery	.0%
Small Interruptible	.0%
Large Interruptible	.0%
Overall	5.4%

Q. Ms. Kivisto, would you explain how Montana-Dakota strives to efficiently provide safe and reliable service to its North Dakota customers?

A. Montana-Dakota works hard to control its costs by continually looking for opportunities that create efficiencies and control costs. In spite of Montana-Dakota's efforts to control costs, the Company is seeing a need for increased revenue as the need to replace existing infrastructure and add new infrastructure continues.

Montana-Dakota continually reviews its field operations for ways to operate more efficiently and has been successful in doing so. Much of this has been possible due to the advancement of cost effective technology. However, additional investments are needed to ensure the system can be operated safely and reliably.

Q. What return is Montana-Dakota requesting in this case?

A. Montana-Dakota is requesting an overall return of 7.542 percent, inclusive of a return on equity (ROE) of 10.0 percent. Dr. Gaske's analysis indicates that a 10.0 percent ROE is fully justified and supported.

Q. Is Montana-Dakota seeking interim rate relief in this proceeding?

A. Yes. Interim rate relief is being sought in this case consistent with North Dakota Century Code 49-05-06. The amount of interim relief sought is $4,561,074 or 4.2 percent and consists of the Company's projected 2018 revenue requirement adjusted to reflect the rate of return of 9.50 percent authorized in Case No. PU-15-090, currently approved depreciation rates, and the exclusion of items that were not a part of the last rate case. The interim request will be described in more detail by Mr. Jacobson. The proposed interim rates are described by Mr. Hatzenbuhler. The interim increase is necessary to provide the Company an opportunity to recover the costs of providing service to customers today.

Q. Will you please identify the witnesses who will testify on behalf of Montana-Dakota in this proceeding?

A. Yes. Following is a list of witnesses that will provide testimony and/or exhibits in support of the Company's application:

- Dr. J. Stephen Gaske, Senior Vice President of Concentric Energy Advisors, Inc. will testify regarding the appropriate cost of common equity for Montana-Dakota's North Dakota gas operations.
- Mr. Patrick C. Darras, Vice President of Operations for Montana-Dakota and Great Plains Natural Gas Co. will testify regarding the North Dakota gas distribution operations and the System Safety and Integrity Program.
- Ms. Tammy J. Nygard, Controller for Montana-Dakota, will testify regarding the overall cost of capital, capital structure and overall debt costs, including the preferred stock redemption.
- Mr. Earl M. Robinson, Principal and Director of AUS will testify regarding the Common and Gas Depreciation Studies that support the proposed depreciation rates in this filing.
- Mr. Matthew Shoemake, Regulatory Analyst for Montana-Dakota will testify regarding the volumes projected in this case.
- Mr. Travis R. Jacobson, Regulatory Analysis Manager for Montana-Dakota, will testify regarding the total revenue requirement and the interim revenue requirement necessary for North Dakota gas operations.

- Mr. Jordan R. Hatzenbuhler, Senior Regulatory Analyst for Montana-Dakota will testify on the Company's embedded class cost of service study and proposed rate design.
- Ms. Stephanie Bosch, Regulatory Affairs Manager for Montana-Dakota will testify regarding proposed tariff changes, including the SSIP Adjustment Mechanism and a proposed Firm General Contracted Demand Rate.

Q. Ms. Kivisto, are the rates requested in this proceeding just and reasonable?

A. Yes. In my opinion, the proposed rates are just and reasonable as they are reflective of the total costs being incurred by Montana-Dakota to provide safe and reliable natural gas service to its customers. The proposed rates will provide Montana-Dakota the opportunity to earn a fair and reasonable return on its North Dakota natural gas operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

Exhibit No.___(JSG-1)

STATE OF NORTH DAKOTA
BEFORE THE NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Case No. PU-17-___

PREPARED DIRECT TESTIMONY OF

J. STEPHEN GASKE

ON BEHALF OF

MONTANA-DAKOTA UTILITIES CO.

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

A1. My name is J. Stephen Gaske and I am a Senior Vice President of Concentric Energy Advisors, Inc., 1300 19th Street NW, Suite 620, Washington, DC 20036.

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

A2. 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 finance and economics. A copy of my résumé is included as Attachment A to this testimony.

Q3. Have you presented expert testimony in other proceedings?

A3. Yes. I have filed testimony or testified in more than 100 regulatory proceedings in North America. These submissions have included testimony on the cost of capital and capital structure issues for electric and natural gas distribution and oil and natural gas pipeline operations before more than a dozen federal, state and provincial regulatory bodies in the U.S., Canada and Mexico, including the North Dakota Public Service Commission ("Commission"). In addition, I have testified or submitted testimony on issues such as cost allocation, rate design, pricing, regulatory principles, market power, and generating plant economics before more than a dozen federal, state and provincial regulatory bodies in the U.S. and Canada. 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.

I. INTRODUCTION

A. Scope and Overview

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

A4. I have been asked by Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company") to estimate the cost of common equity capital for the Company's natural gas distribution operations in the state of North Dakota. In this testimony, I calculate a range for the cost of common equity capital for Montana-Dakota's North Dakota natural gas distribution 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 gas distribution operations. I then place the Company within the range of reasonableness established by the DCF analyses by comparing the risks of Montana-Dakota's North Dakota natural gas distribution operations to those of the proxy gas distribution companies and by considering several alternative benchmark analyses.

Q5. What rate of return is Montana-Dakota requesting in this proceeding?

A5. Based on its test period capital structure, Montana-Dakota is requesting the following rate of return for its North Dakota natural gas distribution operations:

Table 1: Requested Rate of Return – North Dakota Gas Distribution Operations[1]

Source	Percent	Cost	Overall Rate of Return
Long-Term Debt	43.036%	5.282%	2.273%
Short-term Debt	5.968%	2.831%	0.169%
Common Equity	50.996%	10.000%	5.100%
TOTAL	100.000%		7.542%

As my testimony discusses, an overall allowed rate of return of 7.542 percent, with a 10.0 percent return on common equity, represents the cost of capital for Montana-Dakota's North Dakota natural gas distribution operations at this time.

B. Company Background

Q6. Please describe Montana-Dakota's operations and those of its parent company, MDU Resources Group, Inc.

A6. 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 Montana, North Dakota, South Dakota, and Wyoming. MDU Resources also owns Cascade Natural

[1] Projected average capital structure and rate of return for 2018.

Gas Co., which distributes natural gas in the states of Oregon and Washington; Intermountain Gas Company, which distributes natural gas in the state of Idaho; and Great Plains Natural Gas Co., which distributes natural gas in western Minnesota and southeastern North Dakota.

Through other divisions and subsidiaries, MDU Resources is engaged in utility infrastructure construction services, natural gas gathering and transmission, and construction services and contracting.

Natural gas distribution assets comprised 33.4 percent[2] of MDU Resources' total assets in 2016, and natural gas distribution revenues comprised 18.6 percent[3] of total operating revenues. North Dakota accounted for 13.0 percent of the natural gas distribution operating sales revenues, while Idaho (34.0 percent), Washington (26.0 percent), Montana (8.0 percent), Oregon (8.0 percent), South Dakota (6.0 percent), Minnesota (3.0 percent) and Wyoming (2.0 percent) accounted for the other 87.0 percent of retail gas distribution operating sales revenues.[4]

Q7. Would you please describe Montana-Dakota's North Dakota natural gas distribution service territory?

A7. As discussed in the testimony of Company witness Nicole A. Kivisto, Montana-Dakota provides natural gas distribution service in North Dakota to approximately 109,000 customers in 74 communities, operating approximately 110,000 service lines and 2,575 miles of distribution mains. The customer base in North Dakota is

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2 MDU Resources Group, 2016 SEC Form 10-K, at 81.
3 *Ibid.*, at 80.
4 *Ibid.*, at 12.

86 percent residential customers and 14 percent commercial, industrial and transportation customers.[5] Outside of Bismarck, Montana-Dakota's service territory in North Dakota consists primarily of towns and small cities dotted throughout relatively sparsely populated areas. As such, the economy is heavily dependent on providing retail and other services for surrounding agricultural, mining and petroleum production areas, and several cities are heavily dependent on military bases or government employment.

Q8. What is your understanding of the factors that are driving this rate case filing by Montana-Dakota?

A8. Company witness Kivisto explains that the primary reasons for the filing are increased investment in distribution facilities to improve system safety and reliability and the depreciation and taxes associated with the increase in investment. Ms. Kivisto testifies that Montana-Dakota's gross investment projected for 2018 in North Dakota gas distribution operations is $275 million, or nearly 18 percent greater than the gross investment from the 2015 test year used in the last rate case.

II. FINANCIAL MARKET STUDIES

A. <u>Criteria for a Fair Rate of Return</u>

Q9. Please describe the criteria which should be applied in determining a fair rate of return for a regulated company.

A9. The United States Supreme Court has provided general guidance regarding the level

[5] Montana-Dakota Utilities Company, Annual Report, State of North Dakota, Gas Operations, For the Year Ended December 31, 2016, at 7.

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 Natural Gas 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 compensation 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 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.

Q10. How should a fair rate of return be evaluated from the standpoint of consumers and the public?

A10. The same standards should apply. When an unregulated entity faces competition, the pressure of that competition and consumer choices will combine to determine the fair rate of return. However, 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, both the consumer and the public interest depend on establishing a return that will readily attract capital without being excessive.

Q11. How are the costs of long-term debt determined?

A11. For purposes of setting regulated rates, the current embedded costs of long-term debt are used in order to ensure that the company receives a return that is sufficient to pay the interest obligations that are attached to this source of capital.

Q12. How is the cost of common equity determined?

A12. 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 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 two DCF analyses. In addition, I have conducted two types of risk premium analyses, a market DCF analysis of the S&P 500, and a Capital Asset Pricing Model ("CAPM") analysis as benchmarks to assess the reasonableness of the DCF results. Each of these approaches is described later in this testimony.

B. Interest Rates and the Economy

Q13. What are the general economic factors that affect the cost of capital?

A13. 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 Gross Domestic Product ("GDP") has averaged 2.6 percent annually during the past 30 years, 2.3 percent for the past 20 years, and 1.3 percent for the past 10 years. After increasing at an annual rate of 2.1 percent in the fourth quarter of 2016, the Bureau of Economic Analysis reported that the "second" estimate for the first quarter of 2017 was a real annual economic growth rate of 1.2 percent.[6] According to Blue Chip Economic Indicators, the consensus forecast for expected growth in real GDP is 2.2 percent in 2017[7] and 2.4 percent in 2018.[8] Likewise, the U.S. unemployment rate has improved in recent months to 4.3 percent for May 2017,[9] but the labor force participation rate for civilians 16 years and over was at 62.7 percent for May 2017, remaining near the lowest rate since the late 1970s.[10] Improvements in the U.S.

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6 U.S. Department of Commerce, Bureau of Economic Analysis, News Release, May 27, 2017.
7 Blue Chip Economic Indicators, Vol. 42, No. 6, June 10, 2017, at 2.
8 *Ibid.,* at 3.
9 U.S. Department of Labor, Bureau of Labor Statistics, News Release, June 2, 2017, at 1.
10 Ibid, at 2.

unemployment rate contributed to the Federal Reserve's decision in June 2017 to raise its target range for the federal funds rate to a range between 1.00 – 1.25 percent for overnight loans to banks.[11]

In October 2014, the Federal Open Market Committee ("FOMC") ended its Quantitative Easing program, which provided extraordinary monetary stimulus for the U.S. economy for several years through asset purchases of mortgage-backed securities and Treasury bonds. However, the Federal Reserve's accommodative policy continues today. Specifically, in May the FOMC noted, "[the FOMC's] policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions."[12] But, in June the FOMC announced a contemplated end to accommodative monetary policies later this year by gradually reducing the Federal Reserve's securities holdings by decreasing reinvestment of principal payments from those securities.[13] This new policy will begin to put upward pressure on interest rates by reducing the funds available in the market. According to the July 2017 issue of Blue Chip Financial Forecasts, approximately 81 percent of economists surveyed expect the Federal Reserve will begin to shrink the size of its balance sheet in the second half of 2017.[14]

In addition to the stated expectations of the FOMC, leading economists and market analysts are expecting additional increases in interest rates in the short and medium

11 Statement of the Federal Open Market Committee, June 14, 2017.
12 Statement of the Federal Open Market Committee, May 3, 2017.
13 Statement of the Federal Open Market Committee, June 14, 2017.
14 Blue Chip Financial Forecasts, Vol. 36, No. 7, July 1, 2017, at 14.

term. The July 2017 issue of Blue Chip Financial Forecasts surveyed market participants concerning their views regarding the magnitude and timing of future increases in short-term rates by the Federal Reserve. In response to the question regarding how much more the Federal Reserve will raise interest rates in 2017, 85 percent of those surveyed by Blue Chip expect an additional increase of 25 basis points and 9 percent expect an additional increase of 50 basis points.[15] In response to the same question for 2018, 22 percent of those surveyed expect a total increase in short-term interest rates of 50 basis points in 2018, 44 percent expect a total increase of 75 basis points, and 30 percent expect a total increase of 100 basis points. The average yield on the 30-year U.S. Treasury bond in May 2017 was 2.96 percent. By contrast, the Blue Chip consensus estimate projects that the average yield on the 30-year U.S. Treasury bond will increase to 4.30 percent for the period from 2019 through 2023.[16] Thus, the consensus estimate from leading economists is for an increase of 134 basis points in U.S. Treasury bond yields over the next several years.

As pages 2 and 3 of Schedule 1 of Exhibit No.___(JSG-2) show, interest rates on longer-term U.S. Treasury bonds and A-rated and Baa-rated public utility bonds have increased substantially since August 2016. For example, between August 2016 and May 2017, the average yield on 30-year U.S. Treasury bonds increased from 2.26 percent to 2.96 percent, the average yield on A-rated public utility bonds

[15] Blue Chip Financial Forecasts, Vol. 36, No. 7, July 1, 2017, at 14.
[16] Blue Chip Financial Forecasts, Vol. 36, No. 6, June 1, 2017, at 14.

increased from 3.59 percent to 4.12 percent, and the average yield on Baa-rated public utility bonds increased from 4.20 percent to 4.50 percent.

Investors also are influenced by both the historical and projected level of inflation. As also shown on Page 1 of Schedule 1 of Exhibit No.___(JSG-2), during the past decade, the Consumer Price Index has increased at an average annual rate of 1.8 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 1.6 percent. According to Blue Chip Economic Indicators, the Consumer Price Index is forecasted to increase by 2.3 percent[17] and 2.2 percent[18] for 2017 and 2018, respectively. Over the intermediate and longer-term, however, investors can expect higher inflation rates as the Federal Reserve's accommodative monetary policy, which began in 2008, places upward pressure on consumer and producer prices once economic growth returns to historical levels.

Q14. How are current economic conditions reflected in the equity markets?

A14. The equity markets have recovered from the large stock market decline in 2008 and 2009, but the Federal Reserve's massive purchases of federal debt and mortgage-backed securities have created artificially low interest rates on government bonds and a potential stock market valuation bubble that increases the risks in the equity market.

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17 Blue Chip Economic Indicators, Vol. 42, No. 6, June 10, 2017, at 2.
18 *Ibid.*, at 3.

C. Discounted Cash Flow ("DCF") Method

Q15. Please describe the DCF method of estimating the cost of common equity capital.

A15. The DCF method reflects the assumption that the market price of a share of common 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.

Q16. What is the appropriate DCF formula to use in this proceeding?

A16. 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 ($1 + 0.75g$). Another version assumes that the next dividend payment will be received today. This model multiplies the dividend yield by ($1 + 0.5g$). 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:

$$K = \frac{D_0(1 + 0.625g)}{P} + g$$

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

Q17. 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?

A17. 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 2 of Exhibit No.___(JSG-2) shows a representative sample of flotation costs incurred with 34 new common stock issues by natural gas distribution companies since January 2004. Flotation costs associated with these new issues averaged 4.09 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's North Dakota natural gas distribution operations must have an expected return that places a value on its equity that is approximately 4.0 percent above book value. The cost of common equity capital is therefore the investor return requirement multiplied by 1.04.

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 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 Natural Gas Distribution Companies

Q18. Would you please describe the overall approach used in your DCF analysis of Montana-Dakota's cost of common equity for its North Dakota natural gas distribution operations?

A18. Because Montana-Dakota's North Dakota natural gas distribution operations must compete for capital with many other potential projects and investments, it is essential that the Company have an allowed return that matches returns potentially available from other similarly risky investments. The DCF method generally 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. 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 North Dakota natural gas distribution operations as a stand-alone company is not possible. As an alternative, I have used a group of natural gas distribution companies 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 natural gas distribution operations.

Q19. How did you select a group of natural gas distribution proxy companies?

A19. I started with the eleven companies that The Value Line Investment Survey ("Value Line") classifies as Natural Gas Utilities to ensure that the company is considered to be primarily engaged in the natural gas distribution business and that retention growth rate projections are available. From that group, I eliminated any companies that did not have investment-grade credit ratings from either Standard & Poor's ("S&P") or Moody's Investors Service ("Moody's") because such companies are not sufficiently comparable in terms of business and financial risk to Montana-Dakota. In addition, I excluded any companies that did not pay dividends, or that did not have future growth rate estimates provided by either Zacks or Thomson First Call, or that were currently engaged in significant mergers or acquisitions. In order to ensure that the companies are primarily engaged in the natural gas distribution business, I eliminated any companies that did not derive at least 65 percent of their operating income from regulated natural gas distribution operations in 2016, or that did not have at least 65 percent of their total assets devoted to the provision of natural gas distribution service in 2016. As shown on page 1 of Schedule 3 of Exhibit No.___(JSG-2), seven companies met these criteria for inclusion in the proxy group.

Q20. How did you calculate the dividend yields for the companies in your proxy group?

A20. These calculations are shown on pages 1-2 of Schedule 4 of Exhibit No.___(JSG-2). For the price component of the calculation, I used the average of the high and low stock prices for each month during the six-month period from November 2016 through April 2017. The average monthly dividend yields were calculated for each proxy group company by dividing the prevailing annualized dividend for the period by the average of the stock prices for each month. These dividend yields were then multiplied by the quarterly DCF model factor ($1 + 0.625g$) to arrive at the projected dividend yield component of the DCF model.

Q21. Please describe the method you used to estimate the future growth rate that investors expect from this group of companies.

A21. 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. I developed two different DCF analyses of the proxy companies. In the first approach, I conducted a Basic DCF analysis that relied on analysts' earnings forecasts for the growth rate component of the model. My second approach used a combination of the analysts' earnings growth projections and "sustainable growth" rate forecasts calculated from Value Line data (based on growth from earnings retention and stock issuances) to produce a Blended Growth Rate Analysis.

F. Basic DCF Analysis

Q22. How did you estimate the expected future growth rate in your Basic DCF analysis?

A22. In my Basic DCF analysis, I have estimated expected future growth based on long-term earnings per share growth rate forecasts of investment analysts, which are an important source of information regarding investors' growth rate expectations. This Basic DCF analysis assumes that the analysts' earnings growth forecasts incorporate all information required to estimate a long-term expected growth rate for a company. I have used the consensus estimates of earnings growth forecasts published by Zacks Investment Research and Thomson First Call (as reported on Yahoo! Finance) as the sources for analysts' forecasts in my calculations. As shown on page 2 of Schedule 4 of Exhibit No.___(JSG-2), the average of the analysts' long-term earnings growth rate estimates for the natural gas distribution proxy companies is 5.86 percent, and the median is 6.00 percent.

Q23. How did you calculate the cost of capital using the Basic DCF analysis?

A23. These calculations are shown on page 5 of Schedule 4 of Exhibit No.___(JSG-2). Again, the annual dividend yield is multiplied by the quarterly dividend adjustment factor ($1 + 0.625g$), and this product is added to the growth rate estimate to arrive at the investor-required return. Then, the investor return requirement is multiplied by the flotation cost adjustment factor, 1.04, to arrive at the Basic DCF estimate of the cost of common equity capital for the proxy companies. The Basic DCF analysis indicates a cost of common equity for the proxy companies in a range from 7.11 percent to 11.84 percent. In this analysis, the median for the group is 9.22

percent and the third quartile is 10.22 percent.

G. Blended Growth Rate Analysis

Q24. How did you use your Blended Growth Rate Analysis to estimate investors' long-term growth rate expectations for the proxy companies?

A24. The Blended Growth Rate approach combines: (i) Sustainable growth rates based on Value Line retention growth rate forecasts (B*R), plus earnings accretion from new shares (S*V); and (ii) consensus estimates of long-term earnings growth for each company from various investment analysts, as published by Zacks and Thomson First Call

Q25. What approach did you use in calculating the expected long-term retention growth rate?

A25. The long-term retention growth rate component is based on the calculation of retention growth rates using Value Line forecasts for each company.

Q26. Please describe the retention growth rate component of your analysis.

A26. 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 is 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).

Q27. How can a company's earnings retention rate affect its future growth?

A27. Retention of earnings causes an increase in the book value per share and, other factors being equal, increases the amount of earnings that is generated per share of common stock. The retention growth rate can be estimated by multiplying the expected retention rate (*B*) by 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 12 percent and retain 75 percent of its earnings might be expected to have a growth rate of 9 percent, computed as follows:

$$0.75 \times 12\% = 9\%$$

On the other hand, another company that is also expected to earn 12 percent but only retains 25 percent of its earnings might be expected to have a growth rate of 3 percent, computed as follows:

$$0.25 \times 12\% = 3\%$$

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.

Q28. How can a company increase its earnings per share and future dividends by issuing new common stock?

A28. Firms can grow through external financing by issuing new shares to investors and investing the proceeds to earn a return. If the new equity funds are invested to earn the same rate of return as the existing equity, and the market price per share (M) is greater than the book value per share (B), this source of financing can increase earnings per share so that the earnings of existing shareholders is increased. The amount of growth from external share issuances is represented as:

Growth from new issuances = S*V

Where:
S = the annual percentage increase in common equity from stock issuances;
V = the portion of the stock issuance that increases the book value of existing shareholders;
= 1 – (B/M).

Q29. How did you calculate the expected future sustainable growth rates of the proxy companies?

A29. 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 three to five 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 three to five 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 3 of Schedule 4 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 is being retained and reinvested in the company. This earnings retention rate is multiplied by the projected return on common equity to arrive at the B*R portion of the projected sustainable growth rate. It is also necessary to account for projected earnings growth derived from issuing new shares by the proxy group companies. This is calculated, by multiplying growth in equity from issuing new shares (S) times the portion of new equity that accrues to existing shareholders (V). The S*V portion of the projected sustainable growth rates for each of the proxy companies are also shown on page 3 of Schedule 4 of Exhibit No.___(JSG-2). The average sustainable growth rate, (B*R) + (S*V), for the proxy companies is 5.38 percent, and the median is 5.08 percent.

Q30. How did you utilize the analysts' projected earnings growth rates and the projected sustainable earnings growth rates in estimating expected growth for the proxy companies in the Blended Growth Rate Analysis?

A30. As shown on page 4 of Schedule 4 of Exhibit No.___(JSG-2), I calculated a weighted average of the analysts' projected earnings growth rates and the sustainable growth rates to derive long-term growth rate estimates for each of the proxy companies. In these calculations, I gave two-thirds weighting to the analysts' earnings growth rate projections and one-third weighting to the projected sustainable growth rates. The average of the blended growth rates for the proxy companies is 5.70 percent, and the median is 5.92 percent.

Q31. How did you utilize these Blended Growth Rate estimates in estimating the return on common equity capital that investors require from the proxy companies?

A31. These calculations are shown on page 6 of Schedule 4 of Exhibit No.___(JSG-2). Again, the annual dividend yield for each company is multiplied by the quarterly dividend adjustment factor ($1 + 0.625g$), and this product is added to the growth rate estimate to arrive at the investor-required return. Finally, the investor return requirement is multiplied by the flotation cost adjustment factor, 1.04, to arrive at the cost of common equity capital for the proxy companies. This Blended Growth Rate Analysis indicates that the cost of common equity capital for the natural gas distribution proxy companies is in a range between 7.85 percent and 10.75 percent. In this analysis, the median for the group is 9.13 percent and the third quartile is 9.64 percent.

Q32. Earlier you discussed the fact that the Federal Reserve Board has been setting interest rates and monetary policy in a way that artificially depresses yields on U.S. Treasury debt. What does this mean for the cost of common equity for gas distribution companies using the DCF model?

A32. The DCF cost of equity results for regulated gas distribution companies are being affected by artificial factors in the current and projected capital markets, including the following two key factors: (1) the Federal Reserve's continuing accommodative monetary policy; (2) and the market's expectation for substantially higher interest rates.

Rising interest rates historically have had a negative effect on stock prices, especially for dividend paying stocks such as utilities. As interest rates increase, the return on gas utility equities may be less attractive to investors as compared with other investments of comparable risk. The market's expectation for rising interest rates suggests that the calculated cost of equity for the proxy companies using current market data is likely to be an artificially depressed estimate of investors' required return at this time. For example, in two recent decisions, the FERC expressed concern that Federal Reserve actions may have artificially reduced current dividend yields for utilities and the results of the DCF model may not be representative of the true cost of capital at this time.[19]

H. Risk Premium Analysis

Q33. Have you conducted additional analysis in determining the cost of equity capital for Montana-Dakota?

A33. 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 subordinate to the claims of bondholders. This priority standing provides bondholders with greater assurances

[19] Opinion No. 531, 147 FERC ¶ 61,234 (2014); aff'd in Opinion No. 531-B, 150 FERC ¶ 61,165 (March 3, 2015); and Opinion No. 551, 156 FERC, ¶ 61,234 (Sept. 28, 2016), para. 120-122.

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 data 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. Duff & Phelps annually publishes extensive data regarding the returns that have been earned on stocks, bonds and U.S. Treasury bills since 1926. Historically, the annual return on large company common stocks has exceeded the return on long-term corporate bonds by a premium of 570 basis points (5.7 percent) per year from 1926-2016.[20] When this premium is added to the average yield on Moody's corporate bonds in recent months of approximately 4.2 percent[21], the result is an investor return requirement for large company stocks of approximately 9.9 percent. However, investors in smaller companies expect higher returns over the long term, due to the additional business and financial risks that smaller companies face. According to Duff & Phelps, companies in the same size range as Montana-Dakota's North Dakota natural gas distribution operations have

[20] Duff & Phelps Valuation Handbook, 2017 U.S. Guide to Cost of Capital, Exhibit 2.3. Calculation: (12.0 percent – 6.3 percent = 5.7 percent)

[21] Exhibit No.___(JSG-2), Schedule 1, at 3. The average yield on Moody's corporate bonds from November 2016 through April 2017 has been 4.24 percent.

had a premium of 1,400 basis points (14.0 percent) over the average return on long-term corporate bonds.[22] When added to the recent average corporate bond yield, this size-related premium suggests an expected return of 18.2 percent. This analysis indicates that the rate of return that I am proposing in this proceeding would be low relative to the historic risk premiums earned by similarly-sized unregulated companies.

Q34. Did you also perform a risk premium analysis that is specific to the natural gas distribution industry?

A34. Yes, I did. Research studies provide empirical support for the proposition that equity risk premia generally increase as interest rates decrease, and vice versa. In fact, the data provided in Schedule 5, Exhibit No.___(JSG-2) produce statistical results that are consistent with existing research in this area. Using this data, I performed a linear regression to estimate the relationship between 30-year U.S. Treasury bonds and the risk premium required for regulated gas distribution companies. The resulting equation is presented in Schedule 5, Exhibit No.__(JSG-2) and re-created below:

Intercept + Coefficient x Bond Yield = Risk Premium

0.08410 + (- 0.5560 x Bond Yield) = Risk Premium

[22] Duff & Phelps Valuation handbook, 2017 U.S. Guide to Cost of Capital, Exhibit 4.1. Duff & Phelps defines size ranges based on market capitalization. I calculated the implied market capitalization for Montana-Dakota's North Dakota natural gas distribution operations based on the Company's pro forma rate base ($135.450 million) and the projected average equity ratio for 2018 (51.00 percent). This places Montana-Dakota's North Dakota natural gas distribution operations in Duff & Phelps' tenth decile. Calculation: 20.3 percent – 6.3 percent = 14.0 percent.

The regression statistics indicate that this equation is statistically significant and the R-square reveals that approximately 80 percent of the variation in the risk premium is explained by the bond yield. The negative coefficient in the above equation demonstrates the inverse relationship between bond yields and the risk premium. For every change of 100 basis points in the bond yield, the risk premium changes by approximately 56 basis points in the opposite direction.

This Risk Premium analysis was conducted using three different risk-free rates: (1) the current average yield on 30-year Treasury bonds; (2) the near-term projected yields on 30-year Treasury bonds in 2017 and 2018; and (3) the longer-term projected yields on 30-year Treasury bonds from 2019-2023. Based on these three interest rates, the regression equation produces an average ROE estimate of 9.96 percent.

I. Market DCF Analysis

Q35. What other analysis did you conduct in determining the cost of equity capital for Montana-Dakota's North Dakota natural gas distribution operations?

A35. For an additional benchmark of the reasonableness of my DCF results, I calculated the current required return for the companies contained in the S&P 500 Index. Using data provided by the Bloomberg Professional service, I performed a market capitalization-weighted DCF calculation on the S&P 500 companies based on the current dividend yields and long-term growth rate estimates as of April 28, 2017. These calculations are shown in Schedule 6 of Exhibit No.___(JSG-2). The current secondary market required ROE for the S&P 500 is 12.54 percent. This analysis demonstrates that the rate of return that I am proposing in this proceeding is low relative to the return required by investors who invest in the S&P 500.

J. Forward-Looking CAPM

Q36. Many analysts would argue that gas distribution companies are less risky than the S&P 500 companies. Does this make the S&P 500 a poor benchmark for evaluating the DCF results?

A36. No. The DCF required return for the S&P 500 is significantly greater than the DCF estimates for the natural gas distribution company proxy group, and the large magnitude of this difference is an indicator that the proxy company DCF results may be on the low side. Some analysts use the CAPM to adjust for differences in risk between the market average and a particular group of proxy companies. While I do not consider the CAPM to be a reliable measure of the cost of capital, one could use it to adjust the S&P 500 results to achieve a risk-adjusted benchmark for the natural gas distribution company proxy group. For example, Beta is frequently used as the measure of relative risk in the CAPM. As shown on Schedule 7 of Exhibit No.___(JSG-2), the average beta reported by Value Line for the proxy companies is 0.73.

Duff & Phelps recommends making a size adjustment to the CAPM results to reflect the differential in investors' return requirements for smaller and larger companies, as measured by market capitalization. On Schedule 8, page 2 of 2, of Exhibit No.___(JSG-2), I calculated the CAPM size premium for the proxy companies using the Duff & Phelps size premium data. The average size adjustment for my proxy group companies is 128 basis points. As shown on Schedule 8, page 1 of 2, of Exhibit No.___(JSG-2), using the Value Line beta estimates and the Duff & Phelps adjustments for CAPM size bias for my proxy companies, the median unbiased CAPM result for my proxy companies is 11.26 percent.

Thus, if one were to use the CAPM as a benchmark of a reasonable return, this benchmark demonstrates that my recommended ROE of 10.0 percent in this proceeding is reasonable.[23]

K. Relative Risk Analysis

Q37. Have you compared the risks faced by Montana-Dakota's North Dakota natural gas distribution operations with the risks faced by the proxy group of companies?

A37. Yes. There are four broad categories of risk that concern investors. These include:

1. Business Risk;
2. Regulatory Risk;
3. Financial Risk; and,
4. Market Risk.

[23] This CAPM calculation is identical to the one adopted by the U.S. Federal Energy Regulatory Commission. *Martha Coakley, et al. v. Bangor Hydro-Electric Company, et al.*, Opinion No. 531, 147 FERC ¶ 61,234 (2014); aff'd in Opinion No. 531-B, 150 FERC ¶ 61,165 (March 3, 2015); and *ABATE, et al. v. MISO, et al.*, Opinion No. 551, 156 FERC, ¶ 61,234 (Sept. 28, 2016), para. 120-122. Note that FERC used the CAPM only as a benchmark, but set the allowed rate of return above the median indicated by a DCF analysis of proxy companies because of the current abnormal financial market conditions. While Opinion No. 531 was recently remanded to the FERC by the D.C. Circuit Court, the Court's decision did not question the finding by the FERC that capital market conditions were anomalous.

Q38. Please describe the business risks inherent in the natural gas distribution industry.

A38. 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 natural gas distribution 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.

Q39. What are some of the business risks faced by Montana-Dakota's North Dakota natural gas distribution operations?

A39. The Company's natural gas distribution operations in North Dakota face many of the same business risks that are associated with other natural gas distribution companies. However, Montana-Dakota's North Dakota natural gas distribution operations face some particular risks that distinguish the Company from the proxy group of distribution companies, including its smaller size, slower customer growth in its service territory, and economic uncertainty associated with the sharp decline in oil prices that has affected the Company's service territory.

As shown on page 1 of Schedule 3 of Exhibit No.___(JSG-2), Montana-Dakota's North Dakota natural gas distribution operations are significantly smaller than the operations of any of the proxy companies and a fraction of the size of the typical proxy company. For example, the 2018 test year adjusted rate base of Montana-Dakota's North Dakota natural gas distribution operations is equal to only 2.4 percent of the fiscal year-end 2016 total assets of the median proxy company. Similarly, Montana-Dakota's North Dakota natural gas distribution 2018 test year requested operating revenues and operating income are only 6.3 percent and 5.1 percent of the year-end 2016 level for the median proxy company, respectively. Thus, depending upon the measure of size, the typical proxy company is somewhere between 16 and 41 times the size of Montana-Dakota's North Dakota natural gas distribution operations. The Company's smaller size has significant implications for business risks. Duff & Phelps has documented the significantly higher returns that generally have been associated with small companies.

With its relatively small revenue base, Montana-Dakota's North Dakota natural gas distribution operations are subject to greater risk that a major employer or industry, such as a government facility, agricultural processing facilities, or petroleum industry, might contract or close. Events such as these could significantly affect overall employment and income in the cities and towns served. Factors that negatively influence the local economy can reduce demand for Montana-Dakota's North Dakota natural gas distribution service and adversely impact investments in facilities used to provide those services.

Q40. Please discuss how local economic conditions affect the business risk of Montana-Dakota's North Dakota gas distribution operations.

A40. There is significant economic uncertainty in the Company's service territory due to the sharp decline in oil prices that has occurred over the past few years, which has contributed to slower customer growth, especially in the regions outside Bismarck, and an increase in late payments. As discussed above, the smaller size of Montana-Dakota's North Dakota gas distribution operations makes the Company particularly vulnerable to the loss of larger customers or the downsizing of facilities.

Q41. In the 2014 rate case settlement, Montana-Dakota was allowed to implement straight fixed-variable rates for its North Dakota residential gas distribution customers. Does this rate design reduce the Company's risk profile relative to the proxy group?

A41. No. Because the ROE recommendation is established for a company based on its risk profile relative to the proxy group, it is necessary to consider whether the companies in the proxy group also have a comparable form of volumetric risk protection. Schedule 9 of Exhibit No.___(JSG-2) shows that 66.7 percent of the operating utilities held by the proxy companies have some form of volumetric risk protection (e.g., revenue decoupling mechanisms, straight fixed-variable rate design, formula rate plans). On that basis, Montana-Dakota's volumetric risk is similar to that of the majority of the operating utility companies held by the proxy group companies. Thus, no adjustment to the authorized return on equity capital for that factor is necessary.

Q42. How do Montana-Dakota's risks compare with those of the proxy companies?

A42. Considering only its smaller size, Montana-Dakota's North Dakota natural gas distribution operations might require a return that is approximately 100 basis points higher than the return required for the typical proxy company. In addition, the Company's operations are concentrated in smaller towns and cities with local economies that are generally less diversified than those of the proxy companies. In summary, Montana-Dakota's North Dakota natural gas distribution operations are riskier than the operations of the proxy companies.

Q43. What are the regulatory risks faced by Montana-Dakota's North Dakota natural gas utility operations?

A43. 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 a natural gas distribution 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 for full cost recovery. In effect, the binding constraint on natural gas distribution companies 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 natural gas distribution companies 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 natural gas distribution industry.

The regulatory environment can significantly affect both the access to, and cost of capital in several ways. As noted by Moody's, "[f]or rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[24] Moody's further noted that:

> Utility rates are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.[25]

Regulatory Research Associates ("RRA") ranks the North Dakota Public Service Commission as Average / 1, which is one notch above average on the nine-point scale.[26] This RRA ranking suggests that the Company provides natural gas distribution service in a regulatory environment that is somewhat more constructive

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24 Moody's Investors Service, *Regulated Electric and Gas Utilities*, December 23, 2013, at 9.

25 *Ibid.*

26 Regulatory Research Associates, North Dakota Commission Profile, accessed June 13, 2017.

than average from an investor perspective. As such, Montana-Dakota's North Dakota natural gas distribution operations should be considered to have slightly below average regulatory risk.

Q44. Would you please describe the relative financial risks for Montana-Dakota's North Dakota natural gas distribution operations?

A44. Financial risk exists to the extent that 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 credit ratings.

Page 2 of Schedule 3 of Exhibit No.___(JSG-2) shows the credit ratings assigned by S&P and Moody's to each of the companies in the comparison group and to MDU Resources, Inc., the parent company of Montana-Dakota. The median S&P credit rating for companies in the proxy group is A-. By comparison, MDU Resources' long-term issuer rating from S&P is BBB+. This suggests that the perceived business and financial risk of MDU Resources' bonds is slightly higher than that of the typical company in the comparison group.

The capital structure data on Schedule 10 of Exhibit No.___(JSG-2) show that Montana-Dakota's filed common equity ratio of 51.00 percent is similar to the

49.84 percent median for the proxy companies as of March 31, 2017, suggesting average financial risk. However, MDU Resources' below-average credit rating suggests that a higher common equity ratio would be required to offset Montana-Dakota's above-average business risks.

Q45. Would you please describe Montana-Dakota's market risks?

A45. 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, the market risk of Montana-Dakota's North Dakota natural gas distribution operations is comparable to that of the companies in the proxy group.

Q46. How do the overall risks of the proxy companies compare with the risks faced by Montana-Dakota's North Dakota natural gas distribution operations?

A46. Montana-Dakota's North Dakota natural gas distribution operations face overall risks that are above the median relative to those of the proxy companies. Montana-Dakota has above-average business risks due primarily to its small size relative to the proxy companies and its exposure to economic uncertainty in its service territory due to the sharp decline in oil prices and the resulting effect on customer growth and employment. Montana-Dakota has average financial risk relative to the proxy group, and somewhat below-average regulatory risk.

The greater business risk leads me to conclude that investors appraise the overall risks of Montana-Dakota's North Dakota natural gas distribution operations to be above average relative to the risks of the proxy companies. Consequently, Montana-Dakota's North Dakota natural gas distribution business requires an allowed rate of return that is significantly above the median of the range for the companies in the proxy group indicated by my DCF analyses.

III. SUMMARY AND CONCLUSIONS

Q47. Please summarize the results of your cost of capital study.

A47. I conducted two DCF analyses on a group of natural gas distribution companies that have a range of risks that is roughly comparable to those of Montana-Dakota's North Dakota natural gas distribution operations. These results are summarized as follows:

Table 2: Summary of DCF Results

	Basic DCF Analysis	Blended Growth Rate DCF Analysis
High	11.84%	10.75%
3rd Quartile	10.22%	9.64%
Median	9.22%	9.13%
1st Quartile	7.82%	8.01%
Low	7.11%	7.85%

In addition, I conducted two risk premium analyses, a market DCF analysis of the S&P 500, and a size-adjusted CAPM analysis to test the reasonableness of my DCF analyses. Those results are summarized as follows:

Table 3: Benchmark Risk Premium and Market DCF Analyses

	Return
Risk Premium (Long-Term Corporate Bonds)	
vs. Large Company Stocks	9.9%
vs. Small Company Stocks	18.2%
Gas Utility Risk Premium (Regression of Authorized ROEs against 30-yr Treasury yields)	10.0%
Market DCF (S&P 500)	12.5%
Forward-Looking CAPM	11.3%

My risk premium, market DCF and size-adjusted CAPM analyses suggest that the median DCF results generally are low relative to current market benchmarks. In particular, the median DCF return estimates are considerably below the 10.0 percent gas utility risk premium return. Similarly, the median DCF estimates for the natural gas distribution proxy companies are well below the 12.5 percent market DCF estimate for the S&P 500 companies and the 11.3 percent size-adjusted CAPM estimate for the natural gas distribution proxy companies.

Q48. What rate of return on common equity do you recommend for Montana-Dakota's North Dakota natural gas distribution operations in this proceeding?

A48. My analyses indicate that an appropriate rate of return on common equity for Montana-Dakota's North Dakota natural gas distribution operations at this time is 10.0 percent, which is between the median and the third quartile of the range for my Basic DCF analysis, lower than my size-adjusted CAPM analysis, and equal to my Gas Utility Risk Premium analysis. This recommended return reflects my assessment that the overall risks of Montana-Dakota's North Dakota natural gas distribution operations are above average relative to those of the proxy companies, and the fact that the median DCF results appear to be low relative to the other benchmarks at this time. Although the Company has average financial risk relative to the proxy companies, it has above average business risks. In addition to its very small size relative to the proxy companies, Montana-Dakota's North Dakota natural gas distribution operations are faced with significant economic uncertainty due to the sharp decline in oil prices that has occurred in recent years. Thus, an allowed rate of return equal to the average utility risk premium (10.0 percent) in my study is appropriately positioned to reflect the risks faced by Montana-Dakota's North Dakota natural gas distribution operations relative to the risks faced by the proxy companies, and also to reflect current conditions in the financial market.

Q49. Does this conclude your Prepared Direct Testimony?

A49. Yes.

J. Stephen Gaske, Ph.D.
Senior Vice President

Steve Gaske has more than 30 years of experience as an economic consultant, researcher, and professor in the fields of public utility economics, finance, and regulation. Dr. Gaske has provided consulting services in more than 300 regulatory, antitrust, tax, and civil proceedings. In addition, he has presented expert testimony in more than 100 state, provincial, and federal regulatory commission hearings in Canada, the U.S. and Mexico.

AREAS OF EXPERTISE

His specialty is the application to regulated industries of inter-related principles from economics, finance and regulatory theory. His areas of expertise include:

- Finance, cost of capital, and risk analysis;
- Rate design, cost allocation, cost of service, and pricing of services;
- Energy markets and the economics of public utilities and energy infrastructure;
- Competition and antitrust principles; and
- Regulatory economics, rules, and policies.

INDUSTRY EXPERTISE

His work has involved:

- Most of the major natural gas pipelines in North America;
- Many electric utilities;
- Many natural gas distribution companies;
- Several major oil pipelines;
- Railroads;
- Postal Service;
- Telephone and satellite telecommunications companies; and
- Sewer and water companies.

REPRESENTATIVE PROJECT EXPERIENCE

Some of the projects on which Dr. Gaske has worked include:

- Advisor to numerous U.S. and Canadian pipelines on economics, pricing strategies and regulatory matters;
- Development of computerized cost of service models for calculating both traditional and levelized rates for gas and oil pipelines, and rates for electric utilities;
- On behalf of a new, greenfield pipeline designed to carry Canadian gas to U.S. New England markets he served as the rate and financial advisor during the development, permitting and financing stages.

- A variety of White Papers on technical aspects of calculating the allowed rate of return for regulated companies, including white papers submitted in proceedings involving FERC generic rate of return for electric utilities, FERC rate of return for gas and oil pipelines, Canadian rate of return for pipelines and utilities;
- An analysis of the applicability of various finance theories to telephone ratemaking by the U. S. Federal Communications Commission;
- A study of the economic structure, risks and cost of capital of the satellite telecommunications industry;
- Author of several issues of the H. Zinder & Associates Summary of Natural Gas Pipeline Rates;
- Several studies of regional natural gas market competition, market power, pricing and capacity needs;
- An evaluation of Federal Energy Regulatory Commission policies designed to promote liquidity in the natural gas commodity markets;
- Numerous studies of electric rate, regulatory and market issues such as canceled plant treatment, time-differentiated rates, non-utility generation, competitive bidding, and open-access transmission;
- Author of two updates of the Edison Electric Institute Glossary of Electric Utility Terms;
- Several studies of pricing, contract provisions, competitive bidding programs, and transmission practices for independent electric generation; and,
- Several reports and projects on incentive regulation and the application of price cap regulation to both electric and natural gas companies.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Dr. Gaske has testified or filed testimony or affidavits in more than 100 regulatory proceedings on the following topics:

Commission	Topic
Alaska Regulatory Commission	Oil Pipeline Rate of Return/Rate Base
Alberta Energy and Utilities Board	Gas Pipeline Cost Allocation/Rate Design
Alberta Utilities Commission	Utility Cost of Capital; Gas Pipeline Contracts and Market Power
Colorado Board of Assessment Appeals	Property Tax Discount Rate
U.S. Economic Regulatory Administration	Gas Distribution Rate Design
U. S. Federal Energy Regulatory Commission	Electric Transmission Rate of Return; Gas Pipeline Cost Allocation and Rate Design; Rate of Return and

	Capital Structure; Competition; Revenue Requirements; Oil Pipeline Rate of Return and Pricing
Idaho Public Utilities Commission	Gas Distribution Rate of Return
Indiana Utilities Regulatory Commission	Electric Cost Allocation/Rate Design
Iowa Utilities Board	Electric Avoided Costs/Externalities
Maine Public Utilities Commission	Electric Rate Design/Demand Management
Comision Reguladora de Energia de México	Gas Pipeline Rate of Return
Montana Public Service Commission	Electric/Gas Distribution Rate of Return; Electric Cost Allocation and Rate Design
Minnesota Public Utilities Commission	Gas Distribution Rate of Return
National Energy Board of Canada	Gas Pipeline Cost Allocation and Rate Design; Oil Pipeline Service Structure and Rates
New Mexico Regulatory Commission	Electric Rate of Return
New York Public Service Commission	Gas Pipeline Capital Structure
New Brunswick Energy and Utilities Board	Gas Distribution Ratemaking
North Dakota Public Service Commission	Electric/Gas Distribution Rate of Return; Natural Gas Market Pricing; Electric Cost Allocation and Rate Design
Nova Scotia Utility and Review Board	Cost Allocation and Pricing of Bridge Access
Ontario Energy Board	Rate of Return; Access to and Pricing of Gas Pipeline Expansions; LNG Regulation
U.S. Postal Rate Commission	Postal Pricing/Rate Design
Régie de l'énergie du Québec	Rate of Return/Regulatory Principles
South Dakota Public Utilities Commission	Gas Distribution Rate of Return
Texas Public Utilities Commission	Electric Cost Allocation and Rate Design
Texas Railroad Commission	Gas Pipeline Cost Allocation/Rate Design
Washington Utilities and Transportation Comm.	Gas Distribution Rate of Return
Wisconsin Public Service Commission	Electric Generation Economics

Wyoming Public Service Commission	Electric/Gas Distribution Rate of Return
Wyoming Board of Equalization	Property Tax Discount Rate

TEACHING/SPEAKING ENGAGEMENTS

Dr. Gaske has spoken on utility finance and economic issues before numerous professional groups. From 1983-1986, he served as Coordinator of the Edison Electric Institute Electric Rate Fundamentals Course. He has lectured on marginal cost estimation for electric utilities at the EEI rate course, and on both low-income rates and natural gas pipeline cost allocation and rate design before the American Gas Association Gas Rate Fundamentals Course. In addition, Dr. Gaske has taught college courses in Public Utility Economics, Transportation, Physical Distribution, Financial Management, Investments, Corporate Finance, and Corporate Financial Theory.

PROFESSIONAL HISTORY

<u>CONSULTING</u>

Concentric Energy Advisors, Inc. (2008 – present)
Senior Vice President

H. Zinder & Associates (1988 – 2008)
President/Senior Vice-President/Consultant

Independent Consulting on Public Utility Issues (1982 - 1988)

Olson & Company, Inc. (1980 – 1981)
Public Utility Consultant

H. Zinder & Associates (1977 – 1980)
Research Assistant and Supervisor of Regulatory Research

<u>ACADEMIC/TEACHING</u>

Trinity University (1986 – 1988)
Assistant Professor of Finance

Indiana University School of Business (1982 - 1986)
Associate Instructor of Public Utilities and Transportation

Northern Virginia Community College (1978)
Lecturer in Accounting

EDUCATION

Ph.D., Indiana University School of Business, 1987
M.B.A., George Washington University, 1977
B.A., University of Virginia, 1975

PROFESSIONAL ASSOCIATIONS

American Economic Association
American Finance Association
American Gas Association Rate Committee (1989-2001)
Energy Bar Association
Financial Management Association

Montana-Dakota Utilities Co.

General Economic Statistics

1987-2016

	[1]	[2]	[3]	[4]	[5]
	Percentage Price Changes				
Year	Consumer Price Index	GDP Implicit Price Deflator	Real GDP Growth	Nominal GDP ($ billions)	Nominal GDP Growth
1986	1.9%	2.0%	3.5%	4,590.2	
1987	3.6%	2.6%	3.5%	4,870.2	6.1%
1988	4.1%	3.5%	4.2%	5,252.6	7.9%
1989	4.8%	3.9%	3.7%	5,657.7	7.7%
1990	5.4%	3.7%	1.9%	5,979.6	5.7%
1991	4.2%	3.3%	-0.1%	6,174.0	3.3%
1992	3.0%	2.3%	3.6%	6,539.3	5.9%
1993	3.0%	2.4%	2.7%	6,878.7	5.2%
1994	2.6%	2.1%	4.0%	7,308.8	6.3%
1995	2.8%	2.1%	2.7%	7,664.1	4.9%
1996	3.0%	1.8%	3.8%	8,100.2	5.7%
1997	2.3%	1.7%	4.5%	8,608.5	6.3%
1998	1.6%	1.1%	4.5%	9,089.2	5.6%
1999	2.2%	1.5%	4.7%	9,660.6	6.3%
2000	3.4%	2.3%	4.1%	10,284.8	6.5%
2001	2.8%	2.3%	1.0%	10,621.8	3.3%
2002	1.6%	1.5%	1.8%	10,977.5	3.3%
2003	2.3%	2.0%	2.8%	11,510.7	4.9%
2004	2.7%	2.7%	3.8%	12,274.9	6.6%
2005	3.4%	3.2%	3.3%	13,093.7	6.7%
2006	3.2%	3.1%	2.7%	13,855.9	5.8%
2007	2.8%	2.7%	1.8%	14,477.6	4.5%
2008	3.8%	2.0%	-0.3%	14,718.6	1.7%
2009	-0.4%	0.8%	-2.8%	14,418.7	-2.0%
2010	1.6%	1.2%	2.5%	14,964.4	3.8%
2011	3.2%	2.1%	1.6%	15,517.9	3.7%
2012	2.1%	1.8%	2.2%	16,155.3	4.1%
2013	1.5%	1.6%	1.7%	16,691.5	3.3%
2014	1.6%	1.8%	2.4%	17,393.1	4.2%
2015	0.1%	1.1%	2.6%	18,036.6	3.7%
2016	1.3%	1.3%	1.6%	18,566.9	2.9%

Average Rate of Change:				[6]	
1987-2016	2.7%	2.2%	2.6%	4.6%	4.8%
1997-2016	2.2%	1.9%	2.3%	3.9%	4.3%
2007-2016	1.8%	1.6%	1.3%	2.5%	3.0%

Notes:

[1] U.S. Department of Labor, Bureau of Labor Statistics; U.S. city average, all urban consumers, all items, not seasonally adjusted

[2] U.S. Department of Commerce, Bureau of Economic Analysis; NIPA Tables 1.1.9, Revised on January 27, 2017

[3] U.S. Department of Commerce, Bureau of Economic Analysis; NIPA Tables 1.1.1, Revised on January 27, 2017

[4] U.S. Department of Commerce, Bureau of Economic Analysis; NIPA Tables 1.1.5, Revised on January 27, 2017

[5] Equals annual percent change of Column [4]

[6] Nominal GDP growth rates based on geometric average rate of change

Montana Dakota Utilities Co.

Bond Yield Averages

January 2010 - May 2017

		[1]	[2]	[3]	[4]	[5]	[6]
		30-year U.S. Treasury Bond	Average Corporate	Public Utility Bonds A-Rated	Public Utility Bonds Baa-Rated	Credit Spreads A-Rated	Credit Spreads Baa-Rated
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	4.64	5.81	5.84	6.22	1.20	1.58
	APR	4.69	5.80	5.81	6.19	1.12	1.49
	MAY	4.29	5.52	5.50	5.97	1.21	1.68
	JUN	4.13	5.52	5.46	6.18	1.34	2.05
	JUL	3.99	5.32	5.26	5.98	1.26	1.98
	AUG	3.80	5.05	5.01	5.55	1.20	1.74
	SEP	3.77	5.05	5.01	5.53	1.24	1.76
	OCT	3.87	5.15	5.10	5.62	1.23	1.75
	NOV	4.19	5.37	5.37	5.85	1.18	1.67
	DEC	4.42	5.55	5.56	6.04	1.14	1.62
2011	JAN	4.52	5.56	5.57	6.06	1.05	1.54
	FEB	4.65	5.66	5.68	6.10	1.03	1.45
	MAR	4.51	5.55	5.56	5.97	1.05	1.46
	APR	4.50	5.56	5.55	5.98	1.05	1.48
	MAY	4.29	5.33	5.32	5.74	1.03	1.45
	JUN	4.23	5.30	5.26	5.67	1.03	1.44
	JUL	4.27	5.30	5.27	5.70	0.99	1.43
	AUG	3.65	4.79	4.69	5.22	1.04	1.57
	SEP	3.18	4.60	4.48	5.11	1.30	1.93
	OCT	3.13	4.60	4.52	5.24	1.39	2.11
	NOV	3.02	4.39	4.25	4.93	1.23	1.92
	DEC	2.98	4.47	4.33	5.07	1.35	2.09
2012	JAN	3.03	4.45	4.34	5.06	1.31	2.04
	FEB	3.11	4.42	4.36	5.02	1.25	1.91
	MAR	3.28	4.54	4.48	5.13	1.20	1.85
	APR	3.18	4.49	4.40	5.11	1.21	1.93
	MAY	2.93	4.33	4.20	4.97	1.27	2.03
	JUN	2.70	4.22	4.08	4.91	1.38	2.21
	JUL	2.59	4.03	3.93	4.85	1.34	2.26
	AUG	2.77	4.09	4.00	4.88	1.23	2.11
	SEP	2.88	4.09	4.02	4.81	1.14	1.93
	OCT	2.90	3.97	3.91	4.54	1.01	1.64
	NOV	2.80	3.92	3.84	4.42	1.03	1.61
	DEC	2.88	4.05	4.00	4.56	1.12	1.67
2013	JAN	3.08	4.19	4.15	4.66	1.07	1.58
	FEB	3.17	4.27	4.18	4.74	1.02	1.58
	MAR	3.16	4.29	4.20	4.72	1.04	1.56
	APR	2.93	4.07	4.00	4.49	1.07	1.55
	MAY	3.11	4.23	4.17	4.65	1.05	1.54
	JUN	3.40	4.63	4.53	5.08	1.13	1.68
	JUL	3.61	4.76	4.68	5.21	1.08	1.60
	AUG	3.76	4.89	4.73	5.28	0.97	1.52
	SEP	3.79	4.95	4.80	5.31	1.02	1.52
	OCT	3.68	4.82	4.70	5.17	1.02	1.49
	NOV	3.80	4.91	4.77	5.24	0.97	1.44
	DEC	3.89	4.92	4.81	5.25	0.92	1.36

Montana Dakota Utilities Co.

Bond Yield Averages

January 2010 - May 2017

		[1]	[2]	[3]	[4]	[5]	[6]
		30-year U.S. Treasury Bond	Average Corporate	Public Utility Bonds A-Rated	Public Utility Bonds Baa-Rated	Credit Spreads A-Rated	Credit Spreads Baa-Rated
2014	JAN	3.77	4.76	4.63	5.09	0.86	1.32
	FEB	3.66	4.68	4.53	5.01	0.87	1.35
	MAR	3.62	4.65	4.51	5.00	0.89	1.37
	APR	3.52	4.52	4.41	4.85	0.89	1.33
	MAY	3.39	4.38	4.26	4.69	0.87	1.30
	JUN	3.42	4.44	4.29	4.73	0.87	1.31
	JUL	3.33	4.37	4.23	4.66	0.89	1.33
	AUG	3.20	4.29	4.13	4.65	0.93	1.45
	SEP	3.26	4.39	4.24	4.79	0.98	1.53
	OCT	3.04	4.22	4.06	4.67	1.02	1.63
	NOV	3.04	4.28	4.09	4.75	1.05	1.71
	DEC	2.83	4.17	3.95	4.70	1.11	1.86
2015	JAN	2.46	3.84	3.58	4.39	1.13	1.94
	FEB	2.57	3.93	3.67	4.44	1.11	1.87
	MAR	2.63	3.98	3.74	4.51	1.12	1.88
	APR	2.59	3.93	3.75	4.51	1.16	1.92
	MAY	2.96	4.35	4.17	4.91	1.22	1.95
	JUN	3.11	4.56	4.39	5.13	1.28	2.01
	JUL	3.07	4.57	4.40	5.22	1.33	2.16
	AUG	2.86	4.48	4.25	5.23	1.39	2.37
	SEP	2.95	4.59	4.39	5.42	1.43	2.47
	OCT	2.89	4.52	4.29	5.47	1.40	2.58
	NOV	3.03	4.62	4.40	5.57	1.37	2.54
	DEC	2.97	4.58	4.35	5.55	1.26	2.12
2016	JAN	2.86	4.56	4.27	5.49	1.41	2.63
	FEB	2.62	4.44	4.12	5.28	1.49	2.66
	MAR	2.68	4.33	4.16	5.12	1.48	2.44
	APR	2.62	4.09	4.00	4.75	1.38	2.12
	MAY	2.63	4.04	3.93	4.60	1.30	1.97
	JUN	2.44	3.90	3.77	4.46	1.33	2.01
	JUL	2.22	3.67	3.57	4.16	1.35	1.94
	AUG	2.26	3.70	3.59	4.20	1.32	1.94
	SEP	2.34	3.78	3.66	4.27	1.31	1.92
	OCT	2.50	3.87	3.77	4.34	1.28	1.85
	NOV	2.88	4.20	4.09	4.65	1.20	1.76
	DEC	3.11	4.36	4.27	4.79	1.16	1.68
2017	JAN	3.02	4.22	4.14	4.62	1.12	1.60
	FEB	3.03	4.24	4.18	4.58	1.15	1.55
	MAR	3.08	4.28	4.23	4.62	1.15	1.53
	APR	2.94	4.16	4.12	4.51	1.18	1.58
	MAY	2.96	4.15	4.12	4.50	1.17	1.54
TTM	AVG	2.73	4.04	3.96	4.47	1.23	1.74

Notes:
[1] Bloomberg Finance L.P., 30-Year U.S. Treasury Bond
[2] Bloomberg Finance L.P., Moody's Average Corporate Bond Index
[3] Bloomberg Finance L.P., Moody's A-Rated Utility Bond Index
[4] Bloomberg Finance L.P., Moody's Baa-Rated Utility Bond Index
[5] Equals Column [3] − Column [1]
[6] Equals Column [4] − Column [1]

Montana-Dakota Utilities Co.

Common Equity Flotation Costs of Natural Gas Distribution Companies

2004-2017

Issuer	Date of Offering	Number of Shares	Issue Price	Net Proceeds Per Share	Financing Costs as a Percent of Net Proceeds
Piedmont Natural Gas Company, Inc.	1/20/2004	4,250,000	$42.50	$41.01	3.63%
MDU Resources Group, Inc.	2/4/2004	2,000,000	$23.32	$22.53	3.52%
UGI Corporation	3/18/2004	7,500,000	$32.10	$30.70	4.58%
Northwest Natural Gas Company	3/30/2004	1,200,000	$31.00	$29.99	3.37%
The Laclede Group, Inc.	5/25/2004	1,500,000	$26.80	$25.93	3.36%
Atmos Energy Corporation	7/13/2004	8,650,000	$24.75	$23.76	4.17%
Southern Union Company	7/26/2004	11,000,000	$18.75	$18.09	3.63%
Aquila, Inc.	8/18/2004	40,000,000	$2.55	$2.45	4.04%
Atmos Energy Corporation	10/21/2004	14,000,000	$24.75	$23.76	4.17%
AGL Resources Inc.	11/19/2004	9,600,000	$31.01	$30.08	3.09%
Cinergy Corporation	12/9/2004	6,100,000	$41.00	$40.51	1.21%
Southern Union Company	2/7/2005	14,910,000	$23.00	$22.30	3.14%
SEMCO Energy, Inc.	8/10/2005	4,300,000	$6.32	$6.07	4.17%
Chesapeake Utilities Corporation	11/16/2006	600,300	$30.10	$28.98	3.88%
Atmos Energy Corporation	12/7/2006	5,500,000	$31.50	$30.40	3.63%
Vectren Corporation	2/22/2007	4,600,000	$28.33	$27.34	3.63%
Unitil Corporation	12/10/2008	2,000,000	$20.00	$18.95	5.54%
Unitil Corporation	5/20/2009	2,400,000	$20.00	$18.95	5.54%
CenterPoint Energy, Inc.	9/10/2009	21,000,000	$12.00	$11.58	3.63%
CenterPoint Energy, Inc.	6/9/2010	22,000,000	$12.90	$12.45	3.63%
NiSource Inc.	9/8/2010	21,100,000	$16.50	$15.96	3.36%
Gas Natural Inc.	11/10/2010	2,100,000	$10.00	$9.40	6.38%
Unitil Corporation	5/10/2012	2,400,000	$25.25	$23.99	5.26%
Gas Natural Inc.	6/27/2012	700,000	$10.10	$9.49	6.38%
Piedmont Natural Gas Company, Inc.	1/29/2013	4,000,000	$32.00	$30.88	3.63%
The Laclede Group, Inc.	5/22/2013	8,700,000	$44.50	$42.78	4.02%
Gas Natural Inc.	7/11/2013	1,500,000	$10.00	$9.43	6.10%
Gas Natural Inc.	10/31/2013	1,134,155	$10.00	$9.43	6.10%
Atmos Energy Corporation	2/11/2014	8,000,000	$44.00	$42.46	3.63%
The Laclede Group, Inc.	6/5/2014	9,000,000	$46.25	$44.54	3.84%
South Jersey Industries, Inc.	5/12/2016	7,000,000	$26.25	$25.33	3.63%
Spire, Inc.	5/12/2016	1,900,000	$63.05	$61.00	3.36%
Chesapeake Utilities Corporation	9/22/2016	960,488	$62.26	$59.93	3.89%
Northwest Natural Gas Company	11/10/2016	1,012,000	$54.63	$52.58	3.90%
			Average 2004-2017:		4.09%
			Selected Flotation Costs for Cost of Equity:		4.00%

Sources: *SNL Financial*

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Fiscal Year 2016 Operating Data

Company	Ticker	Total Assets ($ millions)	Operating Revenues ($ millions)	Operating Income ($ millions)	
Atmos Energy Corporation	ATO	11,194.9	3,349.9	668.0	1/
New Jersey Resources Corporation	NJR	3,727.1	1,880.9	178.1	1/
NiSource Inc.	NI	18,691.9	4,492.5	858.2	2/
Northwest Natural Gas Company	NWN	3,079.8	676.0	139.3	2/
South Jersey Industries, Inc.	SJI	3,730.6	1,036.5	189.3	2/
Southwest Gas Corporation	SWX	5,581.1	2,460.5	295.7	2/
Spire Inc.	SR	6,077.4	1,537.3	282.3	1/
High		18,692	4,493	858	
Average		**7,440**	**2,205**	**373**	
Median		**5,581**	**1,881**	**282**	
Low		3,080	676	139	
MDU North Dakota Gas		**$135.5**	**$118.0**	**$14.3**	3/
MDU North Dakota Distribution % of:					
- Proxy Company Median		2.43%	6.27%	5.07%	

Notes:
1/ Source: SNL Financial LC; data as of September 30, 2016
2/ Source: SNL Financial LC; data as of December 31, 2016
3/ Source: MDU Statement J, page 3, based on test year revenue requirement and rate base

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Credit Ratings

Company	Ticker	Standard & Poor's	Moody's
Atmos Energy Corporation	ATO	A	A2
New Jersey Resources Corporation	NJR	A	Aa2
NiSource Inc.	NI	BBB+	Baa2
Northwest Natural Gas Company	NWN	A+	A3
South Jersey Industries, Inc.	SJI	BBB+	--
Southwest Gas Corporation	SWX	BBB+	--
Spire Inc.	SR	A-	Baa2
Average		**A-**	**A3**
Median		**A-**	**A3**
MDU Resources, Inc.		BBB+	--

Notes:
Source: SNL Financial as of April 28, 2017
New Jersey Resources Corporation rating is for New Jersey Natural Gas Company

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Dividend Yields
November 2016 - April 2017

Company	Ticker	Average Dividend Yield
Atmos Energy Corporation	ATO	2.38%
New Jersey Resources Corporation	NJR	2.76%
NiSource Inc.	NI	2.98%
Northwest Natural Gas Company	NWN	3.20%
South Jersey Industries, Inc.	SJI	3.22%
Southwest Gas Corporation	SWX	2.27%
Spire Inc.	SR	3.19%
Average		**2.86%**
Median		**2.98%**

Company	Ticker	Month	Price Low	Price High	Price Average	Annualized Dividend	Dividend Yield
Atmos Energy Corporation	ATO	Nov-16	$ 70.47	$ 74.15	$ 72.31	$ 1.80	2.49%
		Dec-16	70.16	74.73	72.45	1.80	2.48%
		Jan-17	73.21	76.18	74.70	1.80	2.41%
		Feb-17	74.56	78.29	76.43	1.80	2.36%
		Mar-17	76.25	80.40	78.33	1.80	2.30%
		Apr-17	78.90	81.40	80.15	1.80	2.25%
							2.38%
New Jersey Resources Corporation	NJR	Nov-16	$ 32.25	$ 35.30	$ 33.78	$ 1.02	3.02%
		Dec-16	33.95	37.00	35.48	1.02	2.88%
		Jan-17	34.25	37.70	35.98	1.02	2.84%
		Feb-17	37.10	39.50	38.30	1.02	2.66%
		Mar-17	37.85	39.75	38.80	1.02	2.63%
		Apr-17	39.15	40.95	40.05	1.02	2.55%
							2.76%
NiSource Inc.	NI	Nov-16	$ 21.41	$ 22.58	$ 22.00	$ 0.66	3.00%
		Dec-16	21.47	22.43	21.95	0.66	3.01%
		Jan-17	21.84	22.68	22.26	0.66	2.96%
		Feb-17	21.98	24.01	23.00	0.70	3.04%
		Mar-17	22.99	24.09	23.54	0.70	2.97%
		Apr-17	23.66	24.43	24.05	0.70	2.91%
							2.98%
Northwest Natural Gas Company	NWN	Nov-16	$ 54.85	$ 59.65	$ 57.25	$ 1.88	3.28%
		Dec-16	56.00	61.50	58.75	1.88	3.20%
		Jan-17	57.65	60.55	59.10	1.88	3.18%
		Feb-17	57.45	61.40	59.43	1.88	3.16%
		Mar-17	56.85	60.90	58.88	1.88	3.19%
		Apr-17	58.50	60.50	59.50	1.88	3.16%
							3.20%
South Jersey Industries, Inc.	SJI	Nov-16	$ 28.22	$ 33.85	$ 31.04	$ 1.06	3.40%
		Dec-16	32.70	34.68	33.69	1.09	3.24%
		Jan-17	31.50	34.21	32.86	1.09	3.32%
		Feb-17	32.52	35.02	33.77	1.09	3.23%
		Mar-17	32.93	35.75	34.34	1.09	3.17%
		Apr-17	35.35	38.12	36.74	1.09	2.97%
							3.22%
Southwest Gas Corporation	SWX	Nov-16	$ 70.47	$ 76.20	$ 73.34	$ 1.80	2.45%
		Dec-16	73.33	76.64	74.99	1.80	2.40%
		Jan-17	76.02	80.57	78.30	1.80	2.30%
		Feb-17	78.93	85.54	82.24	1.80	2.19%
		Mar-17	81.63	86.27	83.95	1.80	2.14%
		Apr-17	83.13	85.17	84.15	1.80	2.14%
							2.27%
Spire Inc.	SR	Nov-16	$ 60.75	$ 66.25	$ 63.50	$ 1.96	3.09%
		Dec-16	62.95	65.05	64.00	2.10	3.28%
		Jan-17	63.70	65.60	64.65	2.10	3.25%
		Feb-17	62.60	66.10	64.35	2.10	3.26%
		Mar-17	63.90	67.50	65.70	2.10	3.20%
		Apr-17	67.40	69.80	68.60	2.10	3.06%
							3.19%

Source: Bloomberg Finance L.P.

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Earnings Growth Rate Estimates

Company	Ticker	1/2 Zacks 5-Yr Earnings Growth	1/2 Yahoo Finance! Earnings Growth	Weighted Average
Atmos Energy Corporation	ATO	7.00%	6.90%	6.95%
New Jersey Resources Corporation	NJR	6.00%	6.00%	6.00%
NiSource Inc.	NI	6.20%	8.00%	7.10%
Northwest Natural Gas Company	NWN	4.30%	4.50%	4.40%
South Jersey Industries, Inc.	SJI	10.00%	6.00%	8.00%
Southwest Gas Corporation	SWX	5.00%	4.00%	4.50%
Spire Inc.	SR	4.10%	4.05%	4.08%
Average		**6.09%**	**5.64%**	**5.86%**
Median		**6.00%**	**6.00%**	**6.00%**

Source: Yahoo Finance! and Zacks Investment Research as of April 28, 2017.

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Projected Sustainable Earnings Growth Rates

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]
		Value Line Forecast 2020-22					Common Shares Outstanding			Price 2020-22								
Company	Ticker	EPS	DPS	ROE	Retention Rate	B*R	2017	2020-22	Growth	High	Low	Average	Book Value Per Share 2020-22	Market/ Book Ratio	"S"	"V"	S*V	BR + SV
Atmos Energy Corporation	ATO	$4.50	$2.30	11.50%	48.89%	5.62%	107.00	120.00	2.32%	115.00	95.00	105.00	38.50	2.73	6.33%	63.33%	4.01%	9.63%
New Jersey Resources Corporation	NJR	$2.15	$1.12	12.00%	47.91%	5.75%	86.00	86.00	0.00%	35.00	25.00	30.00	17.80	1.69	0.00%	40.67%	0.00%	5.75%
NiSource Inc.	NI	$1.50	$1.00	12.00%	33.33%	4.00%	325.00	330.00	0.31%	30.00	20.00	25.00	12.75	1.96	0.60%	49.00%	0.29%	4.29%
Northwest Natural Gas Company	NWN	$3.15	$2.05	10.00%	34.92%	3.49%	29.00	30.00	0.68%	60.00	50.00	55.00	31.75	1.73	1.18%	42.27%	0.50%	3.99%
South Jersey Industries, Inc.	SJI	$1.85	$1.30	6.00%	29.73%	1.78%	82.00	86.00	0.96%	35.00	25.00	30.00	29.05	1.03	0.99%	3.17%	0.03%	1.82%
Southwest Gas Corporation	SWX	$4.75	$2.50	12.00%	47.37%	5.68%	49.00	53.00	1.58%	90.00	60.00	75.00	39.60	1.89	3.00%	47.20%	1.41%	7.10%
Spire Inc.	SR	$4.65	$2.50	9.50%	46.24%	4.39%	47.00	50.00	1.25%	85.00	65.00	75.00	48.30	1.55	1.93%	35.60%	0.69%	5.08%
Average																		**5.38%**
Median																		**5.08%**

Source: Value Line, dated March 3, 2017.

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Blended Growth Rate Estimates

Company	Ticker	2/3 Earnings Growth	1/3 Sustainable Growth	Weighted Average
Atmos Energy Corporation	ATO	6.95%	9.63%	7.84%
New Jersey Resources Corporation	NJR	6.00%	5.75%	5.92%
NiSource Inc.	NI	7.10%	4.29%	6.16%
Northwest Natural Gas Company	NWN	4.40%	3.99%	4.26%
South Jersey Industries, Inc.	SJI	8.00%	1.82%	5.94%
Southwest Gas Corporation	SWX	4.50%	7.10%	5.37%
Spire Inc.	SR	4.08%	5.08%	4.41%
Average		**5.86%**	**5.38%**	**5.70%**
Median		**6.00%**	**5.08%**	**5.92%**

Source: Schedule 4, page 2 & 3

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Basic DCF Calculation

Company	Ticker	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
Atmos Energy Corporation	ATO	2.38%	2.48%	6.95%	9.43%	1.04	9.81%
New Jersey Resources Corporation	NJR	2.76%	2.87%	6.00%	8.87%	1.04	9.22%
NiSource Inc.	NI	2.98%	3.12%	7.10%	10.22%	1.04	10.62%
Northwest Natural Gas Company	NWN	3.20%	3.28%	4.40%	7.68%	1.04	7.99%
South Jersey Industries, Inc.	SJI	3.22%	3.38%	8.00%	11.38%	1.04	11.84%
Southwest Gas Corporation	SWX	2.27%	2.33%	4.50%	6.83%	1.04	7.11%
Spire Inc.	SR	3.19%	3.27%	4.08%	7.35%	1.04	7.64%
High					11.38%		11.84%
3rd Quartile					9.82%		10.22%
2nd Quartile (Median)					**8.87%**		**9.22%**
1st Quartile					7.52%		7.82%
Low					6.83%		7.11%

Source: Schedule 2 and Schedule 4, page 1 & 2

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Blended Growth Rate DCF Calculation

Company	Ticker	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market: Investor Required Return	Flotation Cost Adjustment	Primary Market: Cost of Capital
Atmos Energy Corporation	ATO	2.38%	2.50%	7.84%	10.34%	1.04	10.75%
New Jersey Resources Corporation	NJR	2.76%	2.86%	5.92%	8.78%	1.04	9.13%
NiSource Inc.	NI	2.98%	3.10%	6.16%	9.26%	1.04	9.63%
Northwest Natural Gas Company	NWN	3.20%	3.28%	4.26%	7.55%	1.04	7.85%
South Jersey Industries, Inc.	SJI	3.22%	3.34%	5.94%	9.28%	1.04	9.65%
Southwest Gas Corporation	SWX	2.27%	2.35%	5.37%	7.71%	1.04	8.02%
Spire Inc.	SR	3.19%	3.28%	4.41%	7.69%	1.04	8.00%
High					10.34%		10.75%
3rd Quartile					9.27%		9.64%
2nd Quartile (Median)					**8.78%**		**9.13%**
1st Quartile					7.70%		8.01%
Low					7.55%		7.85%

Source: Schedule 2 and Schedule 4, page 1 & 4

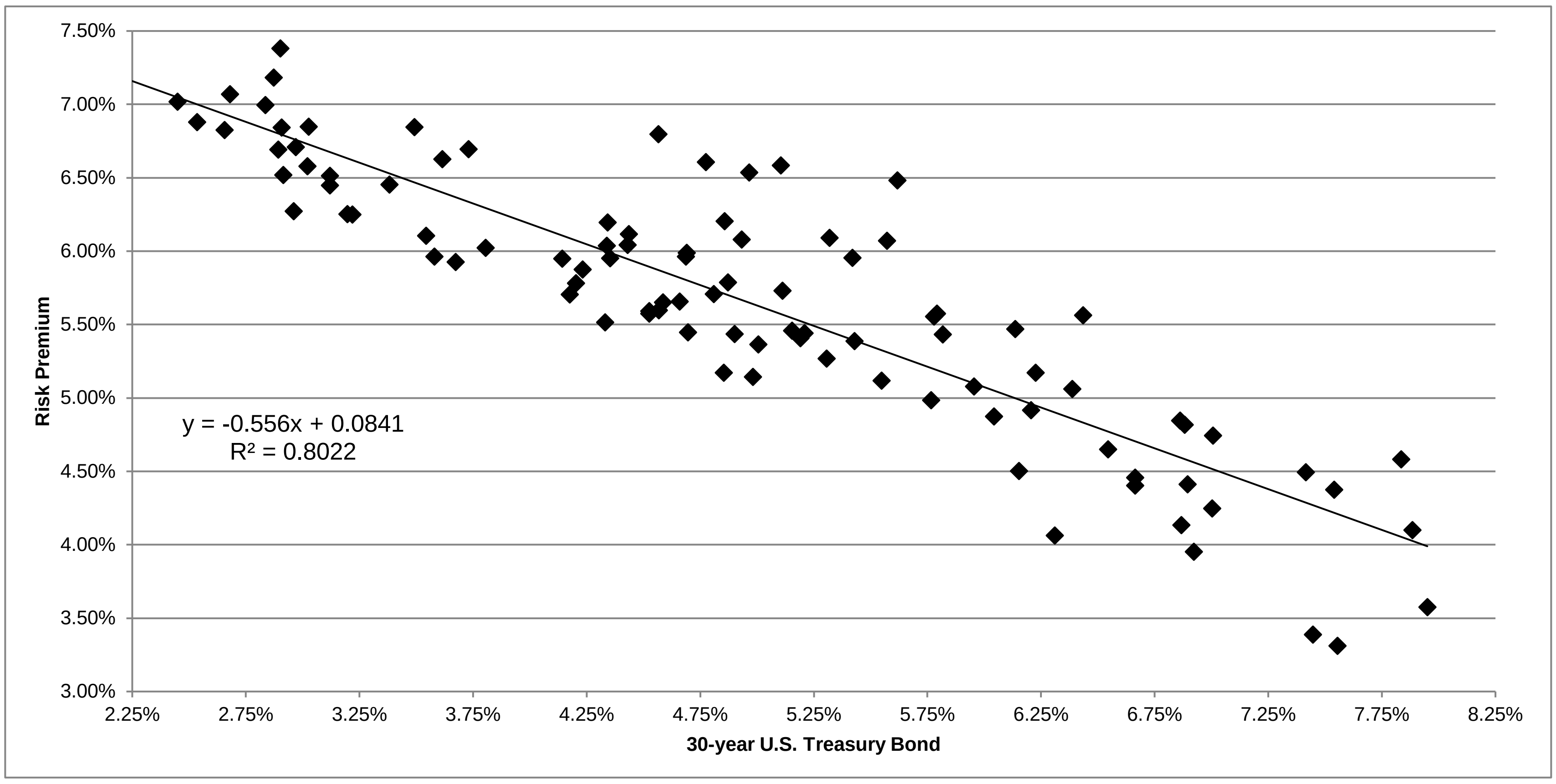
BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Natural Gas ROE	30-year U.S. Treasury Bond	Risk Premium
1992.1	12.42%	7.84%	4.58%
1992.2	11.98%	7.88%	4.10%
1992.3	11.91%	7.42%	4.49%
1992.4	11.92%	7.54%	4.38%
1993.1	11.75%	7.01%	4.74%
1993.2	11.71%	6.86%	4.85%
1993.3	11.40%	6.23%	5.17%
1993.4	11.12%	6.21%	4.92%
1994.1	11.12%	6.66%	4.46%
1994.2	10.84%	7.45%	3.39%
1994.3	10.87%	7.55%	3.31%
1994.4	11.53%	7.95%	3.58%
1995.2	11.00%	6.87%	4.13%
1995.3	11.07%	6.66%	4.40%
1995.4	11.61%	6.14%	5.47%
1996.1	11.45%	6.39%	5.06%
1996.2	10.88%	6.92%	3.95%
1996.3	11.25%	7.00%	4.25%
1996.4	11.19%	6.54%	4.65%
1997.1	11.31%	6.90%	4.41%
1997.2	11.70%	6.88%	4.82%
1997.3	12.00%	6.44%	5.56%
1997.4	10.92%	6.04%	4.87%
1998.2	11.37%	5.79%	5.57%
1998.3	11.41%	5.32%	6.09%
1998.4	11.69%	5.11%	6.59%
1999.1	10.82%	5.43%	5.39%
1999.2	11.25%	5.82%	5.43%
1999.4	10.38%	6.31%	4.06%
2000.1	10.66%	6.15%	4.50%
2000.2	11.03%	5.95%	5.08%
2000.3	11.33%	5.78%	5.56%
2000.4	12.10%	5.62%	6.48%
2001.1	11.38%	5.42%	5.96%
2001.2	10.75%	5.77%	4.98%
2001.4	10.65%	5.21%	5.44%
2002.1	10.67%	5.55%	5.12%
2002.2	11.64%	5.57%	6.07%
2002.3	11.50%	4.96%	6.54%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.78%	6.61%
2003.2	11.36%	4.57%	6.80%
2003.3	10.61%	5.15%	5.46%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.86%	6.20%
2004.2	10.57%	5.31%	5.27%
2004.3	10.37%	5.01%	5.36%
2004.4	10.66%	4.87%	5.79%
2005.1	10.65%	4.69%	5.96%
2005.2	10.54%	4.34%	6.19%
2005.3	10.47%	4.43%	6.04%
2005.4	10.32%	4.66%	5.66%
2006.1	10.68%	4.69%	5.99%
2006.2	10.60%	5.19%	5.41%
2006.3	10.34%	4.90%	5.44%
2006.4	10.14%	4.70%	5.45%

BOND YIELD PLUS RISK PREMIUM

	[1] Average Authorized Natural Gas ROE	[2] 30-year U.S. Treasury Bond	[3] Risk Premium
2007.1	10.52%	4.81%	5.71%
2007.2	10.13%	4.98%	5.14%
2007.3	10.03%	4.85%	5.17%
2007.4	10.12%	4.53%	5.59%
2008.1	10.38%	4.34%	6.04%
2008.2	10.17%	4.57%	5.60%
2008.3	10.55%	4.44%	6.12%
2008.4	10.34%	3.49%	6.85%
2009.1	10.24%	3.62%	6.63%
2009.2	10.11%	4.23%	5.87%
2009.3	9.88%	4.18%	5.70%
2009.4	10.31%	4.35%	5.95%
2010.1	10.24%	4.59%	5.65%
2010.2	9.99%	4.20%	5.78%
2010.3	10.43%	3.73%	6.70%
2010.4	10.09%	4.14%	5.95%
2011.1	10.10%	4.53%	5.57%
2011.2	9.85%	4.33%	5.51%
2011.3	9.65%	3.54%	6.11%
2011.4	9.88%	3.03%	6.85%
2012.1	9.63%	3.12%	6.51%
2012.2	9.83%	2.84%	7.00%
2012.3	9.75%	2.68%	7.07%
2012.4	10.06%	2.87%	7.18%
2013.1	9.57%	3.12%	6.45%
2013.2	9.47%	3.22%	6.25%
2013.3	9.60%	3.67%	5.93%
2013.4	9.83%	3.81%	6.02%
2014.1	9.54%	3.58%	5.96%
2014.2	9.84%	3.38%	6.45%
2014.3	9.45%	3.20%	6.25%
2014.4	10.28%	2.90%	7.38%
2015.1	9.47%	2.45%	7.02%
2015.2	9.43%	2.92%	6.52%
2015.3	9.75%	2.91%	6.84%
2015.4	9.68%	2.97%	6.71%
2016.1	9.48%	2.66%	6.83%
2016.2	9.42%	2.54%	6.88%
2016.3	9.47%	2.24%	7.22%
2016.4	9.59%	2.89%	6.69%
2017.1	9.60%	3.02%	6.58%
2017.2	9.23%	2.96%	6.27%
Average	10.59%	4.92%	5.68%
Median	10.56%	4.86%	5.72%

BOND YIELD PLUS RISK PREMIUM



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.895674832
R Square	0.802233405
Adjusted R Square	0.800173336
Standard Error	0.004084076
Observations	98

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.00649541	0.00649541	389.4207048	1.48518E-35
Residual	96	0.001601249	1.66797E-05		
Total	97	0.008096658			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.084098699	0.001445096	58.19592207	1.12791E-76	0.081230206	0.086967192	0.081230206	0.086967192
30-year U.S. T-Bond	-0.55599725	0.028174948	-19.73374533	1.48518E-35	-0.61192408	-0.50007042	-0.61192408	-0.50007042

	T-Bond	Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	2.80%	6.85%	9.65%
Near-term projected 30-year U.S. Treasury bond yield (Q2 2017 - Q3 2018) [5]	3.40%	6.52%	9.92%
Projected 30-year U.S. Treasury bond yield (2019 - 2023) [6]	4.30%	6.02%	10.32%
MEAN			9.96%

Notes:
[1] Source: Regulatory Research Associates, accessed April 28, 2017
[2] Source: Bloomberg Professional, quarterly bond yields are the daily average of each trading day in the quarter
[3] Equals [1] − [2]
[4] Source: Bloomberg Professional, as of April 28, 2017
[5] Source: Blue Chip Financial Forecasts, Vol. 36, No. 6, June 1, 2017, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 36, No. 6, June 1, 2017, at 14.
[7] See Notes [4], [5] and [6]
[8] Equals 0.084099 + (-0.555997 x [7])
[9] Equals [7] + [8]

Montana-Dakota Utilities Co.

Market DCF Calculation as of April 28, 2017

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.39%**	**2.54%**	**10.00%**	**12.54%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
LyondellBasell Industries NV	LYB	402.8	84.76	34,142	0.1965%	4.01%	6.50%	0.0079%	0.0128%
American Express Co	AXP	893.8	79.25	70,832	0.4077%	1.62%	8.20%	0.0066%	0.0334%
Verizon Communications Inc	VZ	4,079.4	45.91	187,284	1.0781%	5.03%	2.72%	0.0542%	0.0293%
Broadcom Ltd	AVGO	401.4	220.81	88,625	0.5102%	1.85%	15.42%	0.0094%	0.0787%
Boeing Co/The	BA	603.6	184.83	111,560	0.6422%	3.07%	14.33%	0.0197%	0.0920%
Caterpillar Inc	CAT	589.2	102.26	60,247	0.3468%	3.01%	7.64%	0.0104%	0.0265%
JPMorgan Chase & Co	JPM	3,557.9	87.00	309,534	1.7818%	2.30%	7.80%	0.0410%	0.1390%
Chevron Corp	CVX	1,894.6	106.70	202,150	1.1636%	4.05%	28.87%	0.0471%	0.3359%
Coca-Cola Co/The	KO	4,272.6	43.15	184,361	1.0612%	3.43%	5.16%	0.0364%	0.0548%
AbbVie Inc	ABBV	1,593.6	65.94	105,080	0.6049%	3.88%	9.27%	0.0235%	0.0561%
Walt Disney Co/The	DIS	1,581.2	115.60	182,792	1.0522%	1.35%	7.75%	0.0142%	0.0816%
Extra Space Storage Inc	EXR	125.9	75.53	9,510	0.0547%	4.13%	7.54%	0.0023%	0.0041%
EI du Pont de Nemours & Co	DD	867.0	79.75	69,146	0.3980%	1.91%	6.72%	0.0076%	0.0267%
Exxon Mobil Corp	XOM	4,239.7	81.65	346,174	1.9927%	3.77%	13.80%	0.0752%	0.2751%
Phillips 66	PSX	517.0	79.56	41,130	0.0000%	3.17%	-12.32%	0.0000%	0.0000%
General Electric Co	GE	8,708.7	28.99	252,466	1.4533%	3.31%	10.03%	0.0481%	0.1457%
HP Inc	HPQ	1,690.8	18.82	31,821	0.1832%	2.82%	1.75%	0.0052%	0.0032%
Home Depot Inc/The	HD	1,201.2	156.10	187,502	1.0793%	2.28%	12.45%	0.0246%	0.1343%
International Business Machines Corp	IBM	939.5	160.29	150,592	0.8669%	3.74%	6.64%	0.0324%	0.0576%
Concho Resources Inc	CXO	148.2	126.66	18,767	0.0000%	n/a	3.24%	n/a	0.0000%
Johnson & Johnson	JNJ	2,710.9	123.47	334,714	1.9267%	2.72%	6.45%	0.0524%	0.1243%
McDonald's Corp	MCD	816.8	139.93	114,288	0.6579%	2.69%	9.77%	0.0177%	0.0643%
Merck & Co Inc	MRK	2,741.5	62.33	170,880	0.9836%	3.02%	5.36%	0.0297%	0.0527%
3M Co	MMM	597.6	195.83	117,027	0.6737%	2.40%	8.40%	0.0162%	0.0566%
American Water Works Co Inc	AWK	177.7	79.76	14,176	0.0816%	2.08%	7.00%	0.0017%	0.0057%
Bank of America Corp	BAC	10,011.9	23.34	233,679	1.3451%	1.29%	13.94%	0.0173%	0.1875%
CSRA Inc	CSRA	163.1	29.08	4,743	0.0273%	1.38%	6.20%	0.0004%	0.0017%
Pfizer Inc	PFE	5,955.1	33.92	201,998	1.1628%	3.77%	5.08%	0.0439%	0.0590%
Procter & Gamble Co/The	PG	2,557.6	87.33	223,356	1.2857%	3.16%	7.56%	0.0406%	0.0972%
AT&T Inc	T	6,147.0	39.63	243,606	1.4023%	4.95%	4.75%	0.0694%	0.0666%
Travelers Cos Inc/The	TRV	279.4	121.66	33,994	0.1957%	2.37%	6.88%	0.0046%	0.0135%
United Technologies Corp	UTX	801.2	118.99	95,338	0.5488%	2.22%	7.92%	0.0122%	0.0435%
Analog Devices Inc	ADI	365.1	76.20	27,820	0.1601%	2.36%	10.96%	0.0038%	0.0176%
Wal-Mart Stores Inc	WMT	3,031.6	75.18	227,912	1.3119%	2.71%	4.84%	0.0356%	0.0635%
Cisco Systems Inc	CSCO	5,007.9	34.07	170,618	0.9821%	3.40%	7.44%	0.0334%	0.0731%
Intel Corp	INTC	4,709.0	36.15	170,230	0.9799%	3.02%	7.79%	0.0295%	0.0763%
General Motors Co	GM	1,509.1	34.64	52,276	0.3009%	4.39%	10.23%	0.0132%	0.0308%
Microsoft Corp	MSFT	7,720.5	68.46	528,546	3.0425%	2.28%	9.57%	0.0693%	0.2911%
Dollar General Corp	DG	274.9	72.71	19,987	0.1151%	1.43%	9.65%	0.0016%	0.0111%
Kinder Morgan Inc/DE	KMI	2,232.4	20.63	46,055	0.2651%	2.42%	10.00%	0.0064%	0.0265%
Citigroup Inc	C	2,764.9	59.12	163,459	0.9409%	1.08%	4.43%	0.0102%	0.0417%
American International Group Inc	AIG	979.6	60.91	59,665	0.3435%	2.10%	11.00%	0.0072%	0.0378%
Honeywell International Inc	HON	762.3	131.14	99,973	0.5755%	2.03%	9.29%	0.0117%	0.0535%
Altria Group Inc	MO	1,935.7	71.78	138,946	0.7998%	3.40%	7.64%	0.0272%	0.0611%
HCA Holdings Inc	HCA	370.4	84.21	31,195	0.0000%	n/a	11.18%	n/a	0.0000%
Under Armour Inc	UAA	184.7	21.49	3,968	0.0000%	n/a	17.98%	n/a	0.0000%
International Paper Co	IP	412.9	53.97	22,284	0.1283%	3.43%	6.86%	0.0044%	0.0088%
Hewlett Packard Enterprise Co	HPE	1,657.7	18.63	30,883	0.0000%	1.40%	-4.80%	0.0000%	0.0000%
Abbott Laboratories	ABT	1,728.0	43.64	75,410	0.4341%	2.43%	10.70%	0.0105%	0.0464%
Aflac Inc	AFL	401.2	74.88	30,040	0.1729%	2.30%	3.30%	0.0040%	0.0057%
Air Products & Chemicals Inc	APD	217.7	140.50	30,590	0.1761%	2.70%	8.19%	0.0048%	0.0144%
Royal Caribbean Cruises Ltd	RCL	214.9	106.60	22,911	0.1319%	1.80%	18.57%	0.0024%	0.0245%
American Electric Power Co Inc	AEP	491.7	67.83	33,353	0.1920%	3.48%	4.75%	0.0067%	0.0091%
Hess Corp	HES	316.5	48.83	15,456	0.0000%	2.05%	-9.60%	0.0000%	0.0000%
Anadarko Petroleum Corp	APC	558.7	57.02	31,857	0.0000%	0.35%	-0.49%	0.0000%	0.0000%
Aon PLC	AON	262.6	119.84	31,470	0.1812%	1.20%	9.77%	0.0022%	0.0177%
Apache Corp	APA	380.4	48.64	18,501	0.0000%	2.06%	-14.70%	0.0000%	0.0000%
Archer-Daniels-Midland Co	ADM	570.7	45.75	26,108	0.1503%	2.80%	11.86%	0.0042%	0.0178%
Automatic Data Processing Inc	ADP	448.9	104.49	46,906	0.2700%	2.18%	11.02%	0.0059%	0.0297%
Verisk Analytics Inc	VRSK	166.4	82.81	13,778	0.0000%	n/a	10.55%	n/a	0.0000%
AutoZone Inc	AZO	28.4	692.19	19,663	0.0000%	n/a	14.01%	n/a	0.0000%
Avery Dennison Corp	AVY	88.1	83.21	7,333	0.0422%	2.16%	7.10%	0.0009%	0.0030%

Montana-Dakota Utilities Co.

Market DCF Calculation as of April 28, 2017

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.625g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return
S&P 500	**2.39%**	**2.54%**	**10.00%**	**12.54%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Baker Hughes Inc	BHI	425.5	59.37	25,260	0.1454%	1.15%	20.50%	0.0017%	0.0298%
Ball Corp	BLL	175.1	76.89	13,461	0.0775%	0.52%	5.50%	0.0004%	0.0043%
Bank of New York Mellon Corp/The	BK	1,035.6	47.06	48,737	0.2805%	1.62%	12.31%	0.0045%	0.0345%
CR Bard Inc	BCR	72.4	307.48	22,267	0.1282%	0.34%	9.30%	0.0004%	0.0119%
Baxter International Inc	BAX	542.0	55.68	30,176	0.1737%	0.93%	13.08%	0.0016%	0.0227%
Becton Dickinson and Co	BDX	212.8	186.97	39,792	0.2291%	1.56%	10.19%	0.0036%	0.0233%
Berkshire Hathaway Inc	BRK/B	1,310.3	165.21	216,475	0.0000%	n/a	n/a	n/a	n/a
Best Buy Co Inc	BBY	309.1	51.81	16,015	0.0922%	2.63%	11.55%	0.0024%	0.0106%
H&R Block Inc	HRB	207.2	24.79	5,136	0.0296%	3.55%	11.00%	0.0010%	0.0033%
Boston Scientific Corp	BSX	1,369.0	26.38	36,113	0.0000%	n/a	9.80%	n/a	0.0000%
Bristol-Myers Squibb Co	BMY	1,647.4	56.05	92,339	0.5315%	2.78%	15.33%	0.0148%	0.0815%
Fortune Brands Home & Security Inc	FBHS	153.5	63.74	9,784	0.0563%	1.13%	12.48%	0.0006%	0.0070%
Brown-Forman Corp	BF/B	214.8	47.32	10,167	0.0585%	1.54%	1.53%	0.0009%	0.0009%
Cabot Oil & Gas Corp	COG	465.5	23.24	10,819	0.0623%	0.34%	41.29%	0.0002%	0.0257%
Campbell Soup Co	CPB	304.4	57.54	17,514	0.1008%	2.43%	4.98%	0.0025%	0.0050%
Kansas City Southern	KSU	106.1	90.07	9,555	0.0550%	1.47%	12.56%	0.0008%	0.0069%
Advanced Micro Devices Inc	AMD	941.4	13.30	12,521	0.0000%	n/a	8.33%	n/a	0.0000%
Carnival Corp	CCL	536.6	61.77	33,147	0.1908%	2.59%	13.55%	0.0049%	0.0259%
Qorvo Inc	QRVO	126.5	68.03	8,603	0.0000%	n/a	14.07%	n/a	0.0000%
CenturyLink Inc	CTL	548.9	25.67	14,089	0.0000%	8.41%	-0.45%	0.0000%	0.0000%
Cigna Corp	CI	256.7	156.37	40,135	0.2310%	0.03%	11.98%	0.0001%	0.0277%
UDR Inc	UDR	267.4	37.34	9,984	0.0575%	3.32%	6.41%	0.0019%	0.0037%
Clorox Co/The	CLX	128.3	133.69	17,148	0.0987%	2.39%	7.01%	0.0024%	0.0069%
CMS Energy Corp	CMS	280.0	45.40	12,713	0.0732%	2.93%	6.33%	0.0021%	0.0046%
Colgate-Palmolive Co	CL	883.3	72.04	63,632	0.3663%	2.22%	9.04%	0.0081%	0.0331%
Comerica Inc	CMA	176.3	70.70	12,466	0.0718%	1.47%	10.97%	0.0011%	0.0079%
CA Inc	CA	418.0	32.83	13,722	0.0790%	3.11%	6.05%	0.0025%	0.0048%
Conagra Brands Inc	CAG	425.5	38.78	16,501	0.0950%	2.06%	8.65%	0.0020%	0.0082%
Consolidated Edison Inc	ED	305.3	79.28	24,202	0.1393%	3.48%	3.27%	0.0049%	0.0046%
SL Green Realty Corp	SLG	101.8	104.93	10,685	0.0615%	2.95%	0.58%	0.0018%	0.0004%
Corning Inc	GLW	920.2	28.85	26,549	0.1528%	2.15%	9.19%	0.0033%	0.0140%
Cummins Inc	CMI	168.0	150.94	25,354	0.1459%	2.72%	8.50%	0.0040%	0.0124%
Danaher Corp	DHR	694.1	83.33	57,841	0.3330%	0.67%	10.41%	0.0022%	0.0347%
Target Corp	TGT	552.7	55.85	30,867	0.0000%	4.30%	-1.11%	0.0000%	0.0000%
Deere & Co	DE	318.3	111.61	35,524	0.2045%	2.15%	7.70%	0.0044%	0.0157%
Dominion Resources Inc/VA	D	628.2	77.43	48,644	0.2800%	3.90%	5.68%	0.0109%	0.0159%
Dover Corp	DOV	155.7	78.88	12,279	0.0707%	2.23%	13.63%	0.0016%	0.0096%
CBOE Holdings Inc	CBOE	112.0	82.41	9,229	0.0000%	1.21%	n/a	0.0000%	n/a
Dow Chemical Co/The	DOW	1,221.7	62.80	76,723	0.4416%	2.93%	6.58%	0.0129%	0.0291%
Duke Energy Corp	DUK	699.9	82.50	57,740	0.3324%	4.15%	5.05%	0.0138%	0.0168%
Eaton Corp PLC	ETN	448.6	75.64	33,929	0.1953%	3.17%	9.20%	0.0062%	0.0180%
Ecolab Inc	ECL	290.1	129.09	37,443	0.2155%	1.15%	13.00%	0.0025%	0.0280%
PerkinElmer Inc	PKI	109.8	59.41	6,522	0.0375%	0.47%	9.57%	0.0002%	0.0036%
Emerson Electric Co	EMR	645.1	60.28	38,885	0.2238%	3.19%	7.08%	0.0071%	0.0158%
EOG Resources Inc	EOG	577.2	92.50	53,387	0.0000%	0.72%	-6.08%	0.0000%	0.0000%
Entergy Corp	ETR	180.2	76.26	13,739	0.0000%	4.56%	-2.70%	0.0000%	0.0000%
Equifax Inc	EFX	120.2	135.31	16,266	0.0936%	1.15%	8.90%	0.0011%	0.0083%
EQT Corp	EQT	173.3	58.14	10,077	0.0580%	0.21%	15.00%	0.0001%	0.0087%
XL Group Ltd	XL	263.8	41.85	11,039	0.0635%	2.10%	9.00%	0.0013%	0.0057%
Gartner Inc	IT	90.5	114.09	10,320	0.0000%	n/a	14.83%	n/a	0.0000%
FedEx Corp	FDX	267.4	189.70	50,721	0.2920%	0.84%	13.67%	0.0025%	0.0399%
Macy's Inc	M	305.2	29.22	8,918	0.0513%	5.17%	2.63%	0.0027%	0.0013%
FMC Corp	FMC	133.8	73.23	9,800	0.0564%	0.90%	12.00%	0.0005%	0.0068%
Ford Motor Co	F	3,911.1	11.47	44,861	0.2582%	5.23%	3.82%	0.0135%	0.0099%
NextEra Energy Inc	NEE	468.2	133.56	62,528	0.3599%	2.94%	6.75%	0.0106%	0.0243%
Franklin Resources Inc	BEN	561.3	43.11	24,198	0.1393%	1.86%	10.00%	0.0026%	0.0139%
Freeport-McMoRan Inc	FCX	1,446.6	12.75	18,445	0.0000%	n/a	12.55%	n/a	0.0000%
TEGNA Inc	TGNA	214.8	25.48	5,473	0.0315%	2.20%	5.50%	0.0007%	0.0017%
Gap Inc/The	GPS	400.2	26.20	10,486	0.0604%	3.51%	5.46%	0.0021%	0.0033%
General Dynamics Corp	GD	301.7	193.79	58,464	0.3365%	1.73%	8.55%	0.0058%	0.0288%
General Mills Inc	GIS	576.1	57.51	33,134	0.1907%	3.34%	8.10%	0.0064%	0.0154%
Genuine Parts Co	GPC	147.4	92.02	13,563	0.0781%	2.93%	10.32%	0.0023%	0.0081%

Montana-Dakota Utilities Co.

Market DCF Calculation as of April 28, 2017

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.39%**	**2.54%**	**10.00%**	**12.54%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
WW Grainger Inc	GWW	58.4	192.70	11,255	0.0648%	2.66%	12.28%	0.0017%	0.0080%
Halliburton Co	HAL	867.9	45.88	39,818	0.2292%	1.57%	27.00%	0.0036%	0.0619%
Harley-Davidson Inc	HOG	175.6	56.81	9,977	0.0574%	2.57%	8.80%	0.0015%	0.0051%
Harris Corp	HRS	124.5	111.89	13,926	0.0000%	1.89%	n/a	0.0000%	n/a
HCP Inc	HCP	468.4	31.35	14,685	0.0000%	4.72%	-0.01897	0.0000%	0.0000%
Helmerich & Payne Inc	HP	108.6	60.64	6,583	0.0379%	4.62%	4.10%	0.0017%	0.0016%
Fortive Corp	FTV	346.6	63.26	21,925	0.1262%	0.44%	7.65%	0.0006%	0.0097%
Hershey Co/The	HSY	152.2	108.20	16,464	0.0948%	2.28%	9.97%	0.0022%	0.0094%
Synchrony Financial	SYF	810.8	27.80	22,540	0.1298%	1.87%	9.88%	0.0024%	0.0128%
Hormel Foods Corp	HRL	528.9	35.08	18,554	0.1068%	1.94%	4.07%	0.0021%	0.0043%
Arthur J Gallagher & Co	AJG	179.5	55.81	10,017	0.0577%	2.80%	9.95%	0.0016%	0.0057%
Mondelez International Inc	MDLZ	1,524.5	45.03	68,648	0.3952%	1.69%	11.04%	0.0067%	0.0436%
CenterPoint Energy Inc	CNP	431.0	28.53	12,295	0.0708%	3.75%	6.00%	0.0027%	0.0042%
Humana Inc	HUM	144.3	221.98	32,028	0.1844%	0.72%	12.53%	0.0013%	0.0231%
Willis Towers Watson PLC	WLTW	135.4	132.62	17,963	0.1034%	1.60%	11.90%	0.0017%	0.0123%
Illinois Tool Works Inc	ITW	345.7	138.09	47,733	0.2748%	1.88%	8.40%	0.0052%	0.0231%
Ingersoll-Rand PLC	IR	256.0	88.75	22,722	0.1308%	1.80%	10.30%	0.0024%	0.0135%
Foot Locker Inc	FL	131.2	77.34	10,150	0.0584%	1.60%	10.12%	0.0009%	0.0059%
Interpublic Group of Cos Inc/The	IPG	395.1	23.57	9,313	0.0536%	3.05%	9.21%	0.0016%	0.0049%
International Flavors & Fragrances Inc	IFF	79.0	138.59	10,945	0.0630%	1.85%	6.55%	0.0012%	0.0041%
Jacobs Engineering Group Inc	JEC	121.1	54.92	6,649	0.0383%	1.09%	8.49%	0.0004%	0.0032%
Hanesbrands Inc	HBI	372.5	21.81	8,124	0.0468%	2.75%	13.88%	0.0013%	0.0065%
Kellogg Co	K	350.1	71.00	24,854	0.1431%	2.93%	6.82%	0.0042%	0.0098%
Perrigo Co PLC	PRGO	143.4	73.94	10,601	0.0610%	0.87%	5.20%	0.0005%	0.0032%
Kimberly-Clark Corp	KMB	354.9	129.75	46,052	0.2651%	2.99%	6.99%	0.0079%	0.0185%
Kimco Realty Corp	KIM	425.7	20.29	8,637	0.0497%	5.32%	7.66%	0.0026%	0.0038%
Kohl's Corp	KSS	172.4	39.03	6,727	0.0387%	5.64%	5.42%	0.0022%	0.0021%
Oracle Corp	ORCL	4,114.7	44.96	184,996	1.0649%	1.69%	9.22%	0.0180%	0.0982%
Kroger Co/The	KR	914.2	29.65	27,107	0.1560%	1.62%	0.06662	0.0025%	0.0104%
Leggett & Platt Inc	LEG	133.0	52.54	6,987	0.0402%	2.59%	19.00%	0.0010%	0.0076%
Lennar Corp	LEN	203.2	50.50	10,260	0.0591%	0.32%	0.1009	0.0002%	0.0060%
Leucadia National Corp	LUK	359.8	25.39	9,135	0.0526%	0.98%	18.00%	0.0005%	0.0095%
Eli Lilly & Co	LLY	1,103.4	82.06	90,541	0.5212%	2.53%	12.65%	0.0132%	0.0659%
L Brands Inc	LB	284.8	52.81	15,041	0.0866%	4.54%	8.73%	0.0039%	0.0076%
Charter Communications Inc	CHTR	268.9	345.16	92,813	0.0000%	n/a	0.22327	n/a	0.0000%
Lincoln National Corp	LNC	225.5	65.93	14,869	0.0856%	1.76%	9.79%	0.0015%	0.0084%
Loews Corp	L	336.7	46.62	15,696	0.0000%	0.54%	n/a	0.0000%	n/a
Lowe's Cos Inc	LOW	857.3	84.88	72,770	0.4189%	1.65%	14.55%	0.0069%	0.0609%
Host Hotels & Resorts Inc	HST	737.9	17.95	13,246	0.0762%	4.46%	3.40%	0.0034%	0.0026%
Marsh & McLennan Cos Inc	MMC	514.2	74.13	38,115	0.2194%	1.83%	11.78%	0.0040%	0.0258%
Masco Corp	MAS	319.4	37.02	11,823	0.0681%	1.08%	13.68%	0.0007%	0.0093%
Mattel Inc	MAT	342.6	22.42	7,680	0.0442%	6.78%	25.65%	0.0030%	0.0113%
S&P Global Inc	SPGI	257.8	134.19	34,594	0.1991%	1.22%	11.00%	0.0024%	0.0219%
Medtronic PLC	MDT	1,368.9	83.09	113,741	0.6547%	2.07%	6.64%	0.0136%	0.0435%
CVS Health Corp	CVS	1,035.8	82.44	85,391	0.4915%	2.43%	12.09%	0.0119%	0.0594%
Micron Technology Inc	MU	1,106.3	27.67	30,612	0.0000%	n/a	10.00%	n/a	0.0000%
Motorola Solutions Inc	MSI	163.9	85.97	14,090	0.0811%	2.19%	4.65%	0.0018%	0.0038%
Murphy Oil Corp	MUR	172.5	26.18	4,517	0.0000%	3.82%	n/a	0.0000%	n/a
Mylan NV	MYL	535.5	37.35	20,001	0.0000%	n/a	6.47%	n/a	0.0000%
Laboratory Corp of America Holdings	LH	102.3	140.15	14,337	0.0000%	n/a	10.03%	n/a	0.0000%
Newell Brands Inc	NWL	483.1	47.74	23,063	0.1328%	1.59%	11.80%	0.0021%	0.0157%
Newmont Mining Corp	NEM	533.2	33.81	18,029	0.0000%	0.59%	-12.95%	0.0000%	0.0000%
Twenty-First Century Fox Inc	FOXA	1,052.3	30.54	32,138	0.1850%	1.18%	9.84%	0.0022%	0.0182%
NIKE Inc	NKE	1,321.5	55.41	73,225	0.4215%	1.30%	12.13%	0.0055%	0.0511%
NiSource Inc	NI	323.7	24.25	7,850	0.0452%	2.89%	6.38%	0.0013%	0.0029%
Noble Energy Inc	NBL	435.5	32.33	14,079	0.0810%	1.24%	10.62%	0.0010%	0.0086%
Norfolk Southern Corp	NSC	289.8	117.49	34,047	0.1960%	2.08%	11.67%	0.0041%	0.0229%
Eversource Energy	ES	316.9	59.40	18,823	0.1084%	3.20%	6.00%	0.0035%	0.0065%
Northrop Grumman Corp	NOC	174.6	245.96	42,938	0.2472%	1.46%	5.96%	0.0036%	0.0147%
Wells Fargo & Co	WFC	5,003.9	53.84	269,408	1.5508%	2.82%	11.03%	0.0438%	0.1710%
Nucor Corp	NUE	318.9	61.33	19,558	0.1126%	2.46%	6.63%	0.0028%	0.0075%
PVH Corp	PVH	78.2	101.03	7,901	0.0455%	0.15%	8.31%	0.0001%	0.0038%

Montana-Dakota Utilities Co.

Market DCF Calculation as of April 28, 2017

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.39%**	**2.54%**	**10.00%**	**12.54%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Occidental Petroleum Corp	OXY	764.6	61.54	47,052	0.0000%	4.94%	-1.99%	0.0000%	0.0000%
Omnicom Group Inc	OMC	232.9	82.12	19,127	0.1101%	2.68%	7.48%	0.0029%	0.0082%
ONEOK Inc	OKE	210.9	52.61	11,096	0.0639%	4.68%	25.10%	0.0030%	0.0160%
Raymond James Financial Inc	RJF	143.7	74.52	10,707	0.0616%	1.18%	13.50%	0.0007%	0.0083%
PG&E Corp	PCG	510.6	67.05	34,236	0.1971%	2.92%	6.50%	0.0058%	0.0128%
Parker-Hannifin Corp	PH	133.3	160.80	21,434	0.1234%	1.64%	9.81%	0.0020%	0.0121%
PPL Corp	PPL	680.8	38.11	25,945	0.1493%	4.15%	1.70%	0.0062%	0.0025%
PepsiCo Inc	PEP	1,428.5	113.28	161,821	0.9315%	2.66%	6.40%	0.0248%	0.0596%
Exelon Corp	EXC	925.8	34.63	32,059	0.1845%	3.78%	4.33%	0.0070%	0.0080%
ConocoPhillips	COP	1,237.1	47.91	59,267	0.3412%	2.21%	7.00%	0.0075%	0.0239%
PulteGroup Inc	PHM	315.5	22.67	7,152	0.0412%	1.59%	17.05%	0.0007%	0.0070%
Pinnacle West Capital Corp	PNW	111.6	85.09	9,492	0.0546%	3.08%	5.05%	0.0017%	0.0028%
PNC Financial Services Group Inc/The	PNC	486.2	119.75	58,217	0.3351%	1.84%	6.65%	0.0062%	0.0223%
PPG Industries Inc	PPG	256.7	109.84	28,191	0.1623%	1.46%	7.71%	0.0024%	0.0125%
Praxair Inc	PX	285.4	124.98	35,664	0.2053%	2.52%	9.97%	0.0052%	0.0205%
Progressive Corp/The	PGR	580.8	39.72	23,069	0.1328%	1.71%	10.26%	0.0023%	0.0136%
Public Service Enterprise Group Inc	PEG	506.2	44.05	22,299	0.1284%	3.90%	2.37%	0.0050%	0.0030%
Raytheon Co	RTN	291.1	155.21	45,178	0.2601%	2.06%	7.82%	0.0053%	0.0203%
Robert Half International Inc	RHI	127.2	46.05	5,859	0.0337%	2.08%	8.00%	0.0007%	0.0027%
Ryder System Inc	R	53.6	67.91	3,637	0.0209%	2.59%	15.00%	0.0005%	0.0031%
SCANA Corp	SCG	142.9	66.31	9,477	0.0546%	3.69%	5.30%	0.0020%	0.0029%
Edison International	EIX	325.8	79.97	26,055	0.1500%	2.71%	4.76%	0.0041%	0.0071%
Schlumberger Ltd	SLB	1,389.5	72.59	100,862	0.5806%	2.76%	36.05%	0.0160%	0.2093%
Charles Schwab Corp/The	SCHW	1,336.8	38.85	51,934	0.2990%	0.82%	18.17%	0.0025%	0.0543%
Sherwin-Williams Co/The	SHW	93.1	334.68	31,168	0.1794%	1.02%	13.65%	0.0018%	0.0245%
JM Smucker Co/The	SJM	116.4	126.72	14,755	0.0849%	2.37%	5.20%	0.0020%	0.0044%
Snap-on Inc	SNA	57.9	167.53	9,708	0.0559%	1.70%	9.80%	0.0009%	0.0055%
AMETEK Inc	AME	230.0	57.20	13,157	0.0757%	0.63%	9.35%	0.0005%	0.0071%
Southern Co/The	SO	995.2	49.80	49,562	0.2853%	4.66%	4.40%	0.0133%	0.0126%
BB&T Corp	BBT	811.4	43.18	35,035	0.2017%	2.78%	8.41%	0.0056%	0.0170%
Southwest Airlines Co	LUV	614.4	56.22	34,539	0.1988%	0.71%	10.28%	0.0014%	0.0204%
Stanley Black & Decker Inc	SWK	153.0	136.15	20,827	0.1199%	1.70%	11.00%	0.0020%	0.0132%
Public Storage	PSA	173.5	209.38	36,329	0.2091%	3.82%	6.06%	0.0080%	0.0127%
SunTrust Banks Inc	STI	491.4	56.81	27,917	0.1607%	1.83%	8.50%	0.0029%	0.0137%
Sysco Corp	SYY	540.2	52.87	28,561	0.1644%	2.50%	8.86%	0.0041%	0.0146%
Tesoro Corp	TSO	117.4	79.71	9,356	0.0539%	2.76%	10.00%	0.0015%	0.0054%
Texas Instruments Inc	TXN	999.6	79.18	79,151	0.4556%	2.53%	10.34%	0.0115%	0.0471%
Textron Inc	TXT	267.7	46.66	12,490	0.0719%	0.17%	9.66%	0.0001%	0.0069%
Thermo Fisher Scientific Inc	TMO	391.2	165.33	64,680	0.3723%	0.36%	11.98%	0.0014%	0.0446%
Tiffany & Co	TIF	124.8	91.65	11,436	0.0658%	1.96%	8.73%	0.0013%	0.0057%
TJX Cos Inc/The	TJX	644.6	78.64	50,688	0.2918%	1.59%	9.62%	0.0046%	0.0281%
Torchmark Corp	TMK	117.9	76.71	9,044	0.0521%	0.78%	7.57%	0.0004%	0.0039%
Total System Services Inc	TSS	183.4	57.31	10,508	0.0605%	0.70%	11.00%	0.0004%	0.0067%
Johnson Controls International plc	JCI	938.7	41.57	39,022	0.2246%	2.41%	10.50%	0.0054%	0.0236%
Ulta Beauty Inc	ULTA	62.1	281.44	17,488	0.0000%	n/a	22.56%	n/a	0.0000%
Union Pacific Corp	UNP	807.4	111.96	90,401	0.5204%	2.16%	9.82%	0.0112%	0.0511%
UnitedHealth Group Inc	UNH	964.1	174.88	168,604	0.9705%	1.43%	12.98%	0.0139%	0.1260%
Unum Group	UNM	228.2	46.33	10,573	0.0609%	1.73%	6.53%	0.0011%	0.0040%
Marathon Oil Corp	MRO	850.2	14.87	12,642	0.0728%	1.35%	8.60%	0.0010%	0.0063%
Varian Medical Systems Inc	VAR	93.5	90.74	8,480	0.0000%	n/a	n/a	n/a	n/a
Ventas Inc	VTR	354.9	64.01	22,714	0.1308%	4.84%	4.17%	0.0063%	0.0054%
VF Corp	VFC	414.5	54.63	22,645	0.1304%	3.08%	8.23%	0.0040%	0.0107%
Vornado Realty Trust	VNO	189.3	96.24	18,217	0.1049%	2.95%	4.32%	0.0031%	0.0045%
Vulcan Materials Co	VMC	132.6	120.88	16,033	0.0923%	0.83%	28.41%	0.0008%	0.0262%
Weyerhaeuser Co	WY	751.3	33.87	25,446	0.1465%	3.66%	7.50%	0.0054%	0.0110%
Whirlpool Corp	WHR	74.0	185.68	13,735	0.0791%	2.37%	15.88%	0.0019%	0.0126%
Williams Cos Inc/The	WMB	826.2	30.63	25,307	0.1457%	3.92%	10.00%	0.0057%	0.0146%
WEC Energy Group Inc	WEC	315.6	60.52	19,099	0.1099%	3.44%	6.23%	0.0038%	0.0068%
Xerox Corp	XRX	1,016.6	7.19	7,309	0.0421%	3.48%	1.80%	0.0015%	0.0008%
Adobe Systems Inc	ADBE	494.7	133.74	66,161	0.0000%	n/a	17.48%	n/a	0.0000%
AES Corp/VA	AES	659.3	11.31	7,457	0.0429%	4.24%	4.37%	0.0018%	0.0019%
Amgen Inc	AMGN	735.4	163.32	120,105	0.6914%	2.82%	6.81%	0.0195%	0.0471%

Montana-Dakota Utilities Co.

Market DCF Calculation as of April 28, 2017

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.39%**	**2.54%**	**10.00%**	**12.54%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Apple Inc	AAPL	5,246.5	143.65	753,665	4.3384%	1.59%	10.63%	0.0689%	0.4613%
Autodesk Inc	ADSK	220.8	90.07	19,892	0.0000%	n/a	24.33%	n/a	0.0000%
Cintas Corp	CTAS	105.3	122.47	12,899	0.0743%	1.09%	11.15%	0.0008%	0.0083%
Comcast Corp	CMCSA	4,733.5	39.19	185,506	1.0678%	1.61%	10.31%	0.0172%	0.1101%
Molson Coors Brewing Co	TAP	194.7	95.89	18,672	0.1075%	1.71%	16.88%	0.0018%	0.0181%
KLA-Tencor Corp	KLAC	156.8	98.22	15,397	0.0886%	2.20%	4.20%	0.0019%	0.0037%
Marriott International Inc/MD	MAR	382.4	94.42	36,108	0.2079%	1.27%	13.19%	0.0026%	0.0274%
McCormick & Co Inc/MD	MKC	113.2	99.90	11,311	0.0651%	1.88%	7.86%	0.0012%	0.0051%
Nordstrom Inc	JWN	166.9	48.27	8,054	0.0464%	3.07%	7.63%	0.0014%	0.0035%
PACCAR Inc	PCAR	351.3	66.73	23,439	0.1349%	1.50%	6.73%	0.0020%	0.0091%
Costco Wholesale Corp	COST	438.9	177.52	77,921	0.4485%	1.13%	10.40%	0.0051%	0.0466%
Stryker Corp	SYK	373.8	136.37	50,970	0.2934%	1.25%	8.04%	0.0037%	0.0236%
Tyson Foods Inc	TSN	286.9	64.26	18,439	0.1061%	1.40%	6.30%	0.0015%	0.0067%
Applied Materials Inc	AMAT	1,079.8	40.61	43,852	0.2524%	0.99%	15.72%	0.0025%	0.0397%
Time Warner Inc	TWX	775.3	99.27	76,965	0.4430%	1.62%	9.30%	0.0072%	0.0412%
Bed Bath & Beyond Inc	BBBY	145.2	38.75	5,625	0.0324%	1.55%	5.64%	0.0005%	0.0018%
American Airlines Group Inc	AAL	492.6	42.62	20,994	0.0000%	0.94%	-2.71%	0.0000%	0.0000%
Cardinal Health Inc	CAH	315.5	72.59	22,899	0.1318%	2.47%	7.77%	0.0033%	0.0102%
Celgene Corp	CELG	780.8	124.05	96,861	0.0000%	n/a	20.68%	n/a	0.0000%
Cerner Corp	CERN	330.4	64.75	21,395	0.0000%	n/a	12.82%	n/a	0.0000%
Cincinnati Financial Corp	CINF	164.7	72.09	11,872	0.0000%	2.77%	n/a	0.0000%	n/a
DR Horton Inc	DHI	375.6	32.89	12,353	0.0711%	1.22%	11.77%	0.0009%	0.0084%
Flowserve Corp	FLS	130.5	50.87	6,638	0.0382%	1.49%	11.74%	0.0006%	0.0045%
Electronic Arts Inc	EA	308.3	94.82	29,230	0.0000%	n/a	11.27%	n/a	0.0000%
Express Scripts Holding Co	ESRX	593.5	61.34	36,407	0.0000%	n/a	11.99%	n/a	0.0000%
Expeditors International of Washington Inc	EXPD	180.7	56.09	10,135	0.0583%	1.43%	7.85%	0.0008%	0.0046%
Fastenal Co	FAST	289.3	44.68	12,924	0.0744%	2.86%	14.55%	0.0021%	0.0108%
M&T Bank Corp	MTB	153.8	155.41	23,896	0.1376%	1.93%	0.06573	0.0027%	0.0090%
Fiserv Inc	FISV	212.4	119.14	25,303	0.0000%	n/a	10.13%	n/a	0.0000%
Fifth Third Bancorp	FITB	750.6	24.43	18,338	0.1056%	2.29%	2.53%	0.0024%	0.0027%
Gilead Sciences Inc	GILD	1,307.2	68.55	89,611	0.0000%	3.03%	-0.33%	0.0000%	0.0000%
Hasbro Inc	HAS	125.0	99.11	12,389	0.0713%	2.30%	9.45%	0.0016%	0.0067%
Huntington Bancshares Inc/OH	HBAN	1,087.1	12.86	13,980	0.0805%	2.49%	10.35%	0.0020%	0.0083%
Welltower Inc	HCN	363.2	71.44	25,947	0.1494%	4.87%	4.59%	0.0073%	0.0069%
Biogen Inc	BIIB	212.1	271.21	57,528	0.0000%	n/a	7.70%	n/a	0.0000%
Range Resources Corp	RRC	247.6	26.49	6,559	0.0000%	0.30%	-10.13%	0.0000%	0.0000%
Northern Trust Corp	NTRS	229.5	90.00	20,654	0.1189%	1.69%	13.15%	0.0020%	0.0156%
Paychex Inc	PAYX	359.2	59.28	21,296	0.1226%	3.10%	9.00%	0.0038%	0.0110%
People's United Financial Inc	PBCT	343.5	17.47	6,001	0.0345%	3.95%	2.00%	0.0014%	0.0007%
Patterson Cos Inc	PDCO	97.1	44.49	4,321	0.0249%	2.34%	4.76%	0.0006%	0.0012%
QUALCOMM Inc	QCOM	1,477.4	53.74	79,397	0.4570%	4.24%	8.72%	0.0194%	0.0398%
Roper Technologies Inc	ROP	101.9	218.70	22,280	0.1283%	0.64%	12.87%	0.0008%	0.0165%
Ross Stores Inc	ROST	392.0	65.00	25,480	0.1467%	0.98%	12.45%	0.0014%	0.0183%
IDEXX Laboratories Inc	IDXX	88.1	167.73	14,781	0.0000%	n/a	10.42%	n/a	0.0000%
AutoNation Inc	AN	101.3	42.00	4,253	0.0000%	n/a	7.92%	n/a	0.0000%
Starbucks Corp	SBUX	1,457.4	60.06	87,531	0.5039%	1.67%	17.13%	0.0084%	0.0863%
KeyCorp	KEY	1,082.0	18.24	19,736	0.1136%	1.86%	7.42%	0.0021%	0.0084%
Staples Inc	SPLS	653.1	9.77	6,381	0.0367%	4.91%	0.0594	0.0018%	0.0022%
State Street Corp	STT	381.7	83.90	32,021	0.1843%	1.81%	9.70%	0.0033%	0.0179%
US Bancorp	USB	1,693.2	51.28	86,829	0.4998%	2.18%	8.78%	0.0109%	0.0439%
Symantec Corp	SYMC	618.8	31.63	19,574	0.1127%	0.95%	11.63%	0.0011%	0.0131%
T Rowe Price Group Inc	TROW	241.3	70.89	17,103	0.0985%	3.22%	12.15%	0.0032%	0.0120%
Waste Management Inc	WM	441.9	72.78	32,164	0.1852%	2.34%	10.77%	0.0043%	0.0199%
CBS Corp	CBS	370.0	66.56	24,626	0.1418%	1.08%	12.64%	0.0015%	0.0179%
Allergan PLC	AGN	335.5	243.86	81,814	0.4710%	1.15%	12.73%	0.0054%	0.0599%
Whole Foods Market Inc	WFM	318.6	36.37	11,586	0.0667%	1.54%	3.17%	0.0010%	0.0021%
Constellation Brands Inc	STZ	171.4	172.54	29,581	0.1703%	1.21%	17.83%	0.0021%	0.0304%
Xilinx Inc	XLNX	248.9	63.11	15,710	0.0904%	2.22%	8.84%	0.0020%	0.0080%
DENTSPLY SIRONA Inc	XRAY	230.2	63.24	14,557	0.0838%	0.55%	9.47%	0.0005%	0.0079%
Zions Bancorporation	ZION	202.4	40.03	8,103	0.0466%	0.80%	9.00%	0.0004%	0.0042%
Alaska Air Group Inc	ALK	123.7	85.09	10,525	0.0606%	1.41%	10.66%	0.0009%	0.0065%
Invesco Ltd	IVZ	406.9	32.94	13,402	0.0771%	3.52%	10.79%	0.0027%	0.0083%

Montana-Dakota Utilities Co.

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S&P 500	**2.39%**	**2.54%**	**10.00%**	**12.54%**

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Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Intuit Inc	INTU	255.8	125.21	32,027	0.1844%	1.09%	14.78%	0.0020%	0.0272%
Morgan Stanley	MS	1,852.4	43.37	80,337	0.4625%	1.84%	14.87%	0.0085%	0.0688%
Microchip Technology Inc	MCHP	216.4	75.58	16,358	0.0942%	1.91%	17.52%	0.0018%	0.0165%
Chubb Ltd	CB	465.8	137.25	63,928	0.3680%	2.01%	10.63%	0.0074%	0.0391%
Hologic Inc	HOLX	279.3	45.15	12,610	0.0000%	n/a	10.22%	n/a	0.0000%
Chesapeake Energy Corp	CHK	908.0	5.26	4,776	0.0000%	n/a	-0.57%	n/a	0.0000%
Citizens Financial Group Inc	CFG	509.3	36.71	18,697	0.1076%	1.53%	19.13%	0.0016%	0.0206%
O'Reilly Automotive Inc	ORLY	91.6	248.15	22,742	0.0000%	n/a	15.50%	n/a	0.0000%
Allstate Corp/The	ALL	365.2	81.29	29,687	0.1709%	1.82%	9.70%	0.0031%	0.0166%
FLIR Systems Inc	FLIR	136.4	36.73	5,009	0.0000%	1.63%	n/a	0.0000%	n/a
Equity Residential	EQR	367.1	64.58	23,710	0.1365%	3.12%	9.04%	0.0043%	0.0123%
BorgWarner Inc	BWA	212.2	42.28	8,973	0.0516%	1.32%	6.13%	0.0007%	0.0032%
Newfield Exploration Co	NFX	199.0	34.62	6,888	0.0000%	n/a	20.39%	n/a	0.0000%
Incyte Corp	INCY	204.6	124.28	25,426	0.0000%	n/a	42.38%	n/a	0.0000%
Simon Property Group Inc	SPG	312.3	165.26	51,616	0.2971%	4.24%	7.87%	0.0126%	0.0234%
Eastman Chemical Co	EMN	145.8	79.75	11,630	0.0669%	2.56%	7.25%	0.0017%	0.0049%
AvalonBay Communities Inc	AVB	137.5	189.84	26,099	0.1502%	2.99%	6.96%	0.0045%	0.0105%
Prudential Financial Inc	PRU	430.4	107.03	46,063	0.2652%	2.80%	9.70%	0.0074%	0.0257%
United Parcel Service Inc	UPS	689.2	107.46	74,064	0.4263%	3.09%	8.50%	0.0132%	0.0362%
Apartment Investment & Management Co	AIV	157.0	43.74	6,868	0.0395%	3.29%	25.40%	0.0013%	0.0100%
Walgreens Boots Alliance Inc	WBA	1,081.0	86.54	93,545	0.5385%	1.73%	10.65%	0.0093%	0.0573%
McKesson Corp	MCK	212.1	138.29	29,325	0.1688%	0.81%	7.18%	0.0014%	0.0121%
Lockheed Martin Corp	LMT	289.4	269.45	77,990	0.4489%	2.70%	7.35%	0.0121%	0.0330%
AmerisourceBergen Corp	ABC	217.3	82.05	17,828	0.1026%	1.78%	9.46%	0.0018%	0.0097%
Capital One Financial Corp	COF	482.7	80.38	38,800	0.2233%	1.99%	4.52%	0.0044%	0.0101%
Waters Corp	WAT	80.1	169.89	13,604	0.0000%	n/a	7.51%	n/a	0.0000%
Dollar Tree Inc	DLTR	236.3	82.77	19,558	0.0000%	n/a	15.23%	n/a	0.0000%
Darden Restaurants Inc	DRI	124.3	85.19	10,592	0.0610%	2.63%	9.69%	0.0016%	0.0059%
NetApp Inc	NTAP	271.0	39.85	10,797	0.0622%	1.91%	10.16%	0.0012%	0.0063%
Citrix Systems Inc	CTXS	151.2	80.94	12,237	0.0000%	n/a	10.34%	n/a	0.0000%
Goodyear Tire & Rubber Co/The	GT	251.8	36.23	9,122	0.0000%	1.10%	n/a	0.0000%	n/a
DXC Technology Co	DXC	283.6	75.34	21,368	0.0000%	n/a	n/a	n/a	n/a
DaVita Inc	DVA	194.6	69.01	13,429	0.0000%	n/a	8.84%	n/a	0.0000%
Hartford Financial Services Group Inc/The	HIG	367.4	48.36	17,766	0.1023%	1.90%	9.50%	0.0019%	0.0097%
Iron Mountain Inc	IRM	264.1	34.76	9,181	0.0528%	6.33%	11.45%	0.0033%	0.0061%
Estee Lauder Cos Inc/The	EL	222.2	87.14	19,366	0.1115%	1.56%	10.82%	0.0017%	0.0121%
Yahoo! Inc	YHOO	958.1	48.21	46,191	0.0000%	n/a	10.37%	n/a	0.0000%
Principal Financial Group Inc	PFG	288.3	65.13	18,778	0.1081%	2.83%	9.53%	0.0031%	0.0103%
Stericycle Inc	SRCL	85.3	85.34	7,276	0.0000%	n/a	9.95%	n/a	0.0000%
Universal Health Services Inc	UHS	89.4	120.76	10,793	0.0621%	0.33%	9.49%	0.0002%	0.0059%
E*TRADE Financial Corp	ETFC	274.7	34.55	9,491	0.0000%	n/a	16.17%	n/a	0.0000%
Skyworks Solutions Inc	SWKS	184.5	99.74	18,401	0.1059%	1.12%	14.35%	0.0012%	0.0152%
National Oilwell Varco Inc	NOV	380.0	34.97	13,290	0.0000%	0.57%	n/a	0.0000%	n/a
Quest Diagnostics Inc	DGX	136.8	105.51	14,437	0.0831%	1.71%	8.51%	0.0014%	0.0071%
Activision Blizzard Inc	ATVI	753.6	52.25	39,374	0.2267%	0.57%	9.46%	0.0013%	0.0214%
Rockwell Automation Inc	ROK	128.6	157.35	20,235	0.1165%	1.93%	10.99%	0.0023%	0.0128%
Kraft Heinz Co/The	KHC	1,217.1	90.39	110,017	0.6333%	2.66%	10.03%	0.0168%	0.0635%
American Tower Corp	AMT	425.0	125.94	53,526	0.3081%	1.97%	17.98%	0.0061%	0.0554%
Regeneron Pharmaceuticals Inc	REGN	104.4	388.49	40,550	0.0000%	n/a	19.27%	n/a	0.0000%
Amazon.com Inc	AMZN	478.0	924.99	442,122	0.0000%	n/a	35.49%	n/a	0.0000%
Ralph Lauren Corp	RL	56.3	80.72	4,547	0.0262%	2.48%	1.46%	0.0006%	0.0004%
Boston Properties Inc	BXP	153.8	126.60	19,477	0.1121%	2.37%	5.36%	0.0027%	0.0060%
Amphenol Corp	APH	305.4	72.31	22,083	0.1271%	0.89%	10.03%	0.0011%	0.0127%
Arconic Inc	ARNC	440.6	27.33	12,043	0.0693%	0.88%	13.10%	0.0006%	0.0091%
Pioneer Natural Resources Co	PXD	170.2	172.99	29,439	0.1695%	0.05%	20.00%	0.0001%	0.0339%
Valero Energy Corp	VLO	448.7	64.61	28,993	0.1669%	4.33%	13.15%	0.0072%	0.0219%
Synopsys Inc	SNPS	150.5	73.70	11,092	0.0000%	n/a	9.36%	n/a	0.0000%
L3 Technologies Inc	LLL	77.9	171.77	13,377	0.0770%	1.75%	9.77%	0.0013%	0.0075%
Western Union Co/The	WU	476.2	19.86	9,458	0.0544%	3.52%	5.70%	0.0019%	0.0031%
CH Robinson Worldwide Inc	CHRW	141.8	72.70	10,307	0.0593%	2.48%	9.28%	0.0015%	0.0055%
Accenture PLC	ACN	620.1	121.30	75,216	0.4330%	2.00%	10.07%	0.0086%	0.0436%
TransDigm Group Inc	TDG	52.8	246.73	13,038	0.0000%	n/a	9.39%	n/a	0.0000%

Montana-Dakota Utilities Co.

Market DCF Calculation as of April 28, 2017

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.39%**	**2.54%**	**10.00%**	**12.54%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Yum! Brands Inc	YUM	352.3	65.75	23,162	0.1333%	1.83%	13.27%	0.0024%	0.0177%
Prologis Inc	PLD	529.6	54.41	28,813	0.1659%	3.23%	5.09%	0.0054%	0.0084%
FirstEnergy Corp	FE	443.7	29.94	13,286	0.0000%	4.81%	-0.30%	0.0000%	0.0000%
VeriSign Inc	VRSN	101.5	88.92	9,023	0.0000%	n/a	9.30%	n/a	0.0000%
Quanta Services Inc	PWR	148.6	35.44	5,265	0.0000%	n/a	16.80%	n/a	0.0000%
Henry Schein Inc	HSIC	79.7	173.80	13,856	0.0000%	n/a	10.09%	n/a	0.0000%
Ameren Corp	AEE	242.6	54.69	13,270	0.0764%	3.22%	6.00%	0.0025%	0.0046%
Scripps Networks Interactive Inc	SNI	95.9	74.72	7,163	0.0412%	1.61%	7.56%	0.0007%	0.0031%
NVIDIA Corp	NVDA	594.5	104.30	62,010	0.3570%	0.54%	9.40%	0.0019%	0.0336%
Sealed Air Corp	SEE	195.3	44.02	8,598	0.0495%	1.45%	3.47%	0.0007%	0.0017%
Cognizant Technology Solutions Corp	CTSH	589.0	60.23	35,475	0.2042%	1.00%	13.78%	0.0020%	0.0281%
Intuitive Surgical Inc	ISRG	36.8	835.87	30,794	0.0000%	n/a	9.73%	n/a	0.0000%
Affiliated Managers Group Inc	AMG	56.6	165.59	9,370	0.0539%	0.48%	14.31%	0.0003%	0.0077%
Aetna Inc	AET	331.7	135.07	44,806	0.2579%	1.48%	11.72%	0.0038%	0.0302%
Republic Services Inc	RSG	338.1	62.99	21,296	0.1226%	2.03%	9.48%	0.0025%	0.0116%
eBay Inc	EBAY	1,082.3	33.41	36,161	0.0000%	n/a	9.52%	n/a	0.0000%
Goldman Sachs Group Inc/The	GS	397.8	223.80	89,025	0.5125%	1.34%	7.16%	0.0069%	0.0367%
Sempra Energy	SRE	250.6	113.02	28,323	0.1630%	2.91%	7.32%	0.0047%	0.0119%
Moody's Corp	MCO	191.0	118.32	22,601	0.1301%	1.28%	8.00%	0.0017%	0.0104%
Priceline Group Inc/The	PCLN	49.2	1,846.82	90,777	0.0000%	n/a	16.83%	n/a	0.0000%
F5 Networks Inc	FFIV	64.8	129.13	8,366	0.0000%	n/a	12.21%	n/a	0.0000%
Akamai Technologies Inc	AKAM	172.9	60.94	10,538	0.0000%	n/a	14.18%	n/a	0.0000%
Reynolds American Inc	RAI	1,425.9	64.50	91,973	0.5294%	3.16%	8.09%	0.0167%	0.0428%
Devon Energy Corp	DVN	525.7	39.49	20,758	0.1195%	0.61%	18.53%	0.0007%	0.0221%
Alphabet Inc	GOOGL	297.6	924.52	275,151	0.0000%	n/a	16.26%	n/a	0.0000%
Red Hat Inc	RHT	177.8	88.08	15,659	0.0000%	n/a	14.90%	n/a	0.0000%
Allegion PLC	ALLE	95.3	78.64	7,493	0.0431%	0.81%	13.02%	0.0004%	0.0056%
Netflix Inc	NFLX	431.0	152.20	65,599	0.0000%	n/a	36.35%	n/a	0.0000%
Agilent Technologies Inc	A	322.3	55.05	17,743	0.1021%	0.96%	8.88%	0.0010%	0.0091%
Anthem Inc	ANTM	265.0	177.89	47,138	0.2713%	1.46%	8.29%	0.0040%	0.0225%
CME Group Inc	CME	339.8	116.19	39,480	0.2273%	2.27%	9.84%	0.0052%	0.0224%
Juniper Networks Inc	JNPR	382.5	30.07	11,501	0.0662%	1.33%	9.32%	0.0009%	0.0062%
BlackRock Inc	BLK	161.8	384.57	62,223	0.3582%	2.60%	13.87%	0.0093%	0.0497%
DTE Energy Co	DTE	179.4	104.59	18,762	0.1080%	3.16%	5.50%	0.0034%	0.0059%
Nasdaq Inc	NDAQ	166.1	68.87	11,442	0.0659%	2.21%	8.35%	0.0015%	0.0055%
Philip Morris International Inc	PM	1,553.1	110.84	172,150	0.9910%	3.75%	9.47%	0.0372%	0.0938%
salesforce.com Inc	CRM	711.3	86.12	61,260	0.0000%	n/a	25.53%	n/a	0.0000%
MetLife Inc	MET	1,080.4	51.81	55,978	0.3222%	3.09%	7.04%	0.0100%	0.0227%
Under Armour Inc	UA	220.2	19.41	4,275	0.0000%	n/a	11.28%	n/a	0.0000%
Monsanto Co	MON	438.8	116.61	51,169	0.2945%	1.85%	10.10%	0.0055%	0.0297%
Coach Inc	COH	280.6	39.39	11,053	0.0636%	3.43%	11.00%	0.0022%	0.0070%
Fluor Corp	FLR	139.7	51.32	7,171	0.0413%	1.64%	16.85%	0.0007%	0.0070%
CSX Corp	CSX	922.6	50.84	46,906	0.2700%	1.57%	9.90%	0.0042%	0.0267%
Edwards Lifesciences Corp	EW	209.8	109.67	23,009	0.0000%	n/a	16.68%	n/a	0.0000%
Ameriprise Financial Inc	AMP	153.9	127.85	19,672	0.1132%	2.60%	10.40%	0.0029%	0.0118%
Xcel Energy Inc	XEL	507.8	45.05	22,875	0.1317%	3.20%	6.10%	0.0042%	0.0080%
Rockwell Collins Inc	COL	162.4	104.09	16,902	0.0973%	1.27%	9.57%	0.0012%	0.0093%
TechnipFMC PLC	FTI	466.6	30.13	14,058	0.0000%	n/a	-6.85%	n/a	0.0000%
Zimmer Biomet Holdings Inc	ZBH	201.2	119.65	24,076	0.1386%	0.80%	8.38%	0.0011%	0.0116%
CBRE Group Inc	CBG	337.9	35.81	12,099	0.0000%	n/a	10.23%	n/a	0.0000%
Mastercard Inc	MA	1,053.9	116.32	122,592	0.7057%	0.76%	15.87%	0.0053%	0.1120%
Signet Jewelers Ltd	SIG	68.3	65.84	4,497	0.0259%	1.88%	5.63%	0.0005%	0.0015%
CarMax Inc	KMX	185.7	58.50	10,864	0.0000%	n/a	12.32%	n/a	0.0000%
Intercontinental Exchange Inc	ICE	593.5	60.20	35,726	0.2057%	1.33%	11.30%	0.0027%	0.0232%
Fidelity National Information Services Inc	FIS	329.7	84.19	27,759	0.1598%	1.38%	11.10%	0.0022%	0.0177%
Chipotle Mexican Grill Inc	CMG	28.7	474.47	13,600	0.0000%	n/a	20.00%	n/a	0.0000%
Wynn Resorts Ltd	WYNN	101.9	123.01	12,537	0.0722%	1.63%	17.20%	0.0012%	0.0124%
Assurant Inc	AIZ	55.4	96.24	5,329	0.0307%	2.20%	21.41%	0.0007%	0.0066%
NRG Energy Inc	NRG	316.1	16.90	5,342	0.0000%	0.71%	n/a	0.0000%	n/a
Regions Financial Corp	RF	1,205.3	13.75	16,572	0.0954%	2.04%	8.95%	0.0019%	0.0085%
Monster Beverage Corp	MNST	567.8	45.38	25,767	0.0000%	n/a	19.30%	n/a	0.0000%
Teradata Corp	TDC	130.9	29.18	3,819	0.0000%	n/a	4.76%	n/a	0.0000%

Montana-Dakota Utilities Co.

Market DCF Calculation as of April 28, 2017

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.39%**	**2.54%**	**10.00%**	**12.54%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Mosaic Co/The	MOS	351.0	26.93	9,453	0.0544%	4.08%	17.50%	0.0022%	0.0095%
Expedia Inc	EXPE	138.1	133.72	18,473	0.1063%	0.84%	19.18%	0.0009%	0.0204%
Discovery Communications Inc	DISCA	153.5	28.78	4,418	0.0000%	n/a	14.07%	n/a	0.0000%
CF Industries Holdings Inc	CF	233.2	26.74	6,235	0.0000%	4.49%	-0.05%	0.0000%	0.0000%
Viacom Inc	VIAB	347.5	42.56	14,788	0.0851%	1.88%	1.59%	0.0016%	0.0014%
Wyndham Worldwide Corp	WYN	104.4	95.31	9,946	0.0573%	2.43%	12.90%	0.0014%	0.0074%
Alphabet Inc	GOOG	347.0	905.96	314,336	0.0000%	n/a	16.26%	n/a	0.0000%
Mead Johnson Nutrition Co	MJN	183.6	88.72	16,293	0.0938%	1.86%	4.93%	0.0017%	0.0046%
Cooper Cos Inc/The	COO	48.9	200.33	9,803	0.0564%	0.03%	11.64%	0.0000%	0.0066%
TE Connectivity Ltd	TEL	355.0	77.37	27,468	0.1581%	1.91%	6.75%	0.0030%	0.0107%
Discover Financial Services	DFS	383.9	62.59	24,028	0.1383%	1.92%	6.91%	0.0027%	0.0096%
TripAdvisor Inc	TRIP	128.4	45.01	5,780	0.0000%	n/a	15.53%	n/a	0.0000%
Dr Pepper Snapple Group Inc	DPS	183.8	91.65	16,847	0.0970%	2.53%	8.58%	0.0025%	0.0083%
Visa Inc	V	1,846.3	91.22	168,415	0.9695%	0.72%	17.43%	0.0070%	0.1690%
Mid-America Apartment Communities Inc	MAA	113.6	99.21	11,268	0.0000%	3.51%	n/a	0.0000%	n/a
Xylem Inc/NY	XYL	179.7	51.41	9,238	0.0532%	1.40%	15.00%	0.0007%	0.0080%
Marathon Petroleum Corp	MPC	527.9	50.94	26,890	0.1548%	2.83%	16.55%	0.0044%	0.0256%
Level 3 Communications Inc	LVLT	361.3	60.76	21,955	0.0000%	n/a	5.00%	n/a	0.0000%
Tractor Supply Co	TSCO	129.9	61.91	8,043	0.0463%	1.55%	13.80%	0.0007%	0.0064%
Mettler-Toledo International Inc	MTD	25.9	513.42	13,301	0.0000%	n/a	11.78%	n/a	0.0000%
Albemarle Corp	ALB	110.8	108.91	12,062	0.0694%	1.18%	11.60%	0.0008%	0.0081%
Transocean Ltd	RIG	390.9	11.03	4,312	0.0000%	n/a	-29.00%	n/a	0.0000%
Essex Property Trust Inc	ESS	65.6	244.47	16,027	0.0923%	2.86%	6.95%	0.0026%	0.0064%
GGP Inc	GGP	883.4	21.61	19,091	0.1099%	4.07%	5.90%	0.0045%	0.0065%
Realty Income Corp	O	273.1	58.35	15,933	0.0917%	4.34%	5.07%	0.0040%	0.0046%
Seagate Technology PLC	STX	296.6	42.13	12,497	0.0719%	5.98%	12.45%	0.0043%	0.0090%
WestRock Co	WRK	250.4	53.56	13,412	0.0772%	2.99%	7.31%	0.0023%	0.0056%
Western Digital Corp	WDC	288.1	89.07	25,658	0.1477%	2.25%	13.69%	0.0033%	0.0202%
Church & Dwight Co Inc	CHD	254.0	49.53	12,582	0.0724%	1.53%	9.02%	0.0011%	0.0065%
Federal Realty Investment Trust	FRT	72.2	130.89	9,447	0.0544%	2.99%	6.26%	0.0016%	0.0034%
Twenty-First Century Fox Inc	FOX	798.5	29.86	23,844	0.1373%	1.21%	9.84%	0.0017%	0.0135%
Alliant Energy Corp	LNT	227.8	39.32	8,958	0.0516%	3.20%	6.40%	0.0017%	0.0033%
JB Hunt Transport Services Inc	JBHT	110.0	89.66	9,861	0.0568%	1.03%	13.43%	0.0006%	0.0076%
Lam Research Corp	LRCX	161.3	144.85	23,366	0.1345%	1.24%	11.74%	0.0017%	0.0158%
Mohawk Industries Inc	MHK	74.3	234.79	17,445	0.0000%	n/a	7.01%	n/a	0.0000%
Pentair PLC	PNR	182.2	64.51	11,757	0.0677%	2.14%	5.96%	0.0014%	0.0040%
Vertex Pharmaceuticals Inc	VRTX	249.0	118.30	29,462	0.0000%	n/a	74.91%	n/a	0.0000%
Facebook Inc	FB	2,363.7	150.25	355,151	0.0000%	n/a	25.04%	n/a	0.0000%
United Rentals Inc	URI	84.5	109.66	9,268	0.0000%	n/a	15.17%	n/a	0.0000%
Alexandria Real Estate Equities Inc	ARE	91.1	112.51	10,247	0.0590%	2.95%	6.97%	0.0017%	0.0041%
United Continental Holdings Inc	UAL	314.5	70.21	22,082	0.0000%	n/a	1.90%	n/a	0.0000%
Delta Air Lines Inc	DAL	735.5	45.44	33,422	0.1924%	1.78%	11.44%	0.0034%	0.0220%
Navient Corp	NAVI	284.9	15.20	4,331	0.0249%	4.21%	8.00%	0.0010%	0.0020%
Mallinckrodt PLC	MNK	104.7	46.92	4,912	0.0000%	n/a	6.33%	n/a	0.0000%
News Corp	NWS	199.6	13.00	2,595	0.0149%	1.54%	10.73%	0.0002%	0.0016%
Centene Corp	CNC	172.3	74.40	12,817	0.0000%	n/a	13.22%	n/a	0.0000%
Regency Centers Corp	REG	169.8	63.18	10,730	0.0618%	3.23%	8.57%	0.0020%	0.0053%
Macerich Co/The	MAC	142.4	62.43	8,889	0.0512%	4.55%	8.51%	0.0023%	0.0044%
Martin Marietta Materials Inc	MLM	62.6	220.19	13,791	0.0794%	0.76%	0.22906	0.0006%	0.0182%
Envision Healthcare Corp	EVHC	117.5	56.03	6,585	0.0000%	n/a	9.99%	n/a	0.0000%
PayPal Holdings Inc	PYPL	1,201.3	47.72	57,324	0.0000%	n/a	17.58%	n/a	0.0000%
Coty Inc	COTY	747.1	17.85	13,336	0.0768%	2.80%	1.89%	0.0022%	0.0015%
DISH Network Corp	DISH	227.0	64.44	14,625	0.0000%	n/a	2.99%	n/a	0.0000%
Alexion Pharmaceuticals Inc	ALXN	224.6	127.78	28,694	0.0000%	n/a	21.77%	n/a	0.0000%
News Corp	NWSA	381.9	12.72	4,857	0.0280%	1.57%	10.73%	0.0004%	0.0030%
Global Payments Inc	GPN	152.5	81.76	12,468	0.0718%	0.05%	0.12	0.0000%	0.0086%
Crown Castle International Corp	CCI	366.1	94.60	34,634	0.1994%	4.02%	19.97%	0.0080%	0.0398%
Delphi Automotive PLC	DLPH	269.3	80.40	21,651	0.1246%	1.44%	11.76%	0.0018%	0.0147%
Advance Auto Parts Inc	AAP	73.8	142.14	10,493	0.0604%	0.17%	13.56%	0.0001%	0.0082%
Michael Kors Holdings Ltd	KORS	162.4	37.33	6,064	0.0000%	n/a	0.74%	n/a	0.0000%
Illumina Inc	ILMN	146.0	184.86	26,990	0.0000%	n/a	14.61%	n/a	0.0000%
Acuity Brands Inc	AYI	44.1	176.10	7,765	0.0447%	0.30%	20.00%	0.0001%	0.0089%

Montana-Dakota Utilities Co.

Market DCF Calculation as of April 28, 2017

	[1]	[2]	[3]	[4]
	Dividend Yield	Dividend Yield x (1 + 0.625g)	Expected Growth Rate (g)	Secondary Market Investor Required Return
S&P 500	**2.39%**	**2.54%**	**10.00%**	**12.54%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Alliance Data Systems Corp	ADS	55.9	249.63	13,949	0.0803%	0.83%	14.50%	0.0007%	0.0116%
LKQ Corp	LKQ	308.2	31.24	9,629	0.0000%	n/a	15.00%	n/a	0.0000%
Nielsen Holdings PLC	NLSN	357.3	41.13	14,696	0.0846%	3.31%	10.67%	0.0028%	0.0090%
Garmin Ltd	GRMN	188.1	50.84	9,562	0.0550%	4.01%	2.45%	0.0022%	0.0013%
Cimarex Energy Co	XEC	95.1	116.68	11,098	0.0639%	0.27%	77.89%	0.0002%	0.0498%
Zoetis Inc	ZTS	491.6	56.11	27,585	0.1588%	0.75%	12.25%	0.0012%	0.0195%
Digital Realty Trust Inc	DLR	159.458	114.84	18,312	0.1054%	3.24%	5.10%	0.0034%	0.0054%
Equinix Inc	EQIX	77.912	417.7	32,544	0.1873%	1.92%	24.61%	0.0036%	0.0461%
Discovery Communications Inc	DISCK	228.764	27.98	6,401	0.0000%	n/a	14.07%	n/a	0.0000%
Average for Companies Paying Dividends with Positive Best Long-Term Growth Estimates						**2.24%**	**10.07%**		

Notes:
[1] Equals sum of Column [11]
[2] Equals Column [1] x (1 + 0.625 x Column [3])
[3] Equals sum of Column [12]
[4] Equals Column [2] + Column [3]
[5] Source: Bloomberg Finance L.P.
[6] Source: Bloomberg Finance L.P.
[7] Equals Column [5] x Column [6]
[8] Equals percent of sum of Column [7] if Current Dividend Yield does not equal "n/a" and BEst Long-Term Growth Estimate does not equal "n/a" and is greater than 0%
[9] Source: Bloomberg Finance L.P.
[10] Source: Bloomberg Finance L.P.
[11] Equals Column [8] x Column [9]
[12] Equals Column [8] x Column [10]

Montana-Dakota Utilities Co.
Beta
As of April 28, 2017

Company	Ticker	Value Line
Atmos Energy Corporation	ATO	0.70
New Jersey Resources Corporation	NJR	0.80
NiSource Inc.	NI	NMF
Northwest Natural Gas Company	NWN	0.65
South Jersey Industries, Inc.	SJI	0.80
Southwest Gas Corporation	SWX	0.75
Spire Inc.	SR	0.70
Mean		0.73

Source: Value Line; dated March 3, 2017

Montana-Dakota Utilities Co.

Adjusted CAPM Return
As of April 28, 2017

Company	Ticker	[1] S&P Current Market DCF Return	[2] Near-term projected T-Bond Yield	[3] Market Risk Premium	[4] Value Line Beta	[5] B*RP	[6] Plus: Projected T-Bond Yield	[7] Biased CAPM Return	[8] Ibbotson CAPM Adjustment	[9] Unbiased CAPM
Atmos Energy Corporation	ATO	12.54%	3.52%	9.02%	0.70	6.31%	3.52%	9.83%	0.89%	10.72%
New Jersey Resources Corporation	NJR	12.54%	3.52%	9.02%	0.80	7.22%	3.52%	10.73%	1.51%	12.24%
NiSource Inc.	NI	12.54%	3.52%	9.02%	NMF	6.61%	3.52%	10.13%	0.89%	11.02%
Northwest Natural Gas Company	NWN	12.54%	3.52%	9.02%	0.65	5.86%	3.52%	9.38%	1.66%	11.04%
South Jersey Industries, Inc.	SJI	12.54%	3.52%	9.02%	0.80	7.22%	3.52%	10.73%	1.51%	12.24%
Southwest Gas Corporation	SWX	12.54%	3.52%	9.02%	0.75	6.76%	3.52%	10.28%	0.98%	11.26%
Spire Inc.	SR	12.54%	3.52%	9.02%	0.70	6.31%	3.52%	9.83%	1.51%	11.34%
High								**10.73%**		**12.24%**
Median								**10.13%**		**11.26%**
Low								**9.38%**		**10.72%**

Notes
[1] S&P 500 Market Return as of 4/28/2017; dividend yield adjustment factor sets at (1+0.625g); excludes companies with zero dividend and negative growth rate.
[2] Near-term projected 30-year U.S. Treasury bond yield (Q2 2017 - Q3 2018); Blue Chip Financial Forecasts, Vol.36, No.4, April 1, 2017 at 2.
[3] = [1] - [2]
[4] Value Line; dated March 3, 2017
[5] = [3] x [4] (For NI, use average Value Line Beta)
[6] = [2]
[7] = [5] + [6]
[8] See Schedule 8 page 2
[9] = [7] + [8]

Montana-Dakota Utilities Co.

Adjusted CAPM Return
As of April 28, 2017

		[10]	[11]	[12]	[13]	[14]
Company	Ticker	Shares (million)	Price/Share	Market Capitalization (million)	Size Decile	Ibbotson CAPM Size Adjustment
Atmos Energy Corporation	ATO	105.18	$ 81.02	$ 8,521	3	0.89%
New Jersey Resources Corporation	NJR	86.31	$ 40.35	$ 3,483	5	1.51%
NiSource Inc.	NI	323.70	$ 24.25	$ 7,850	3	0.89%
Northwest Natural Gas Company	NWN	28.64	$ 59.60	$ 1,707	6	1.66%
South Jersey Industries, Inc.	SJI	79.52	$ 37.52	$ 2,983	5	1.51%
Southwest Gas Corporation	SWX	47.55	$ 83.76	$ 3,983	4	0.98%
Spire Inc.	SR	45.74	$ 68.55	$ 3,135	5	1.51%
					Average	**1.28%**

Notes

[10] Bloomberg; dated April 28, 2017.

[11] Bloomberg; dated April 28, 2017.

[12] = [10] x [11]

[13] Duff & Phelps 2017 Valuation Hand Book – U.S. Guide to Cost of Capital Exhibit 7.2.

[14] Duff & Phelps 2017 Valuation Hand Book – U.S. Guide to Cost of Capital Exhibit 4.7.

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Non-Volumetric Rate Design

Company	Ticker	Utility	State	Revenue Decoupling Mechanism	Formula Rate Plan	Straight Fixed-Variable Rate Design	Non-Volumetric Rate Design
				[1]	[1]	[1]	[2]
Atmos Energy Corporation	ATO	Atmos Energy Corporation	CO	N	N	N	N
		Atmos Energy Corporation	KS	N	N	N	N
		Atmos Energy Corporation	KY	N	N	N	N
		Atmos Energy Corporation	LA	N	Y	N	Y
		Atmos Energy Corporation	MS	N	Y	N	Y
		Atmos Energy Corporation	TN	N	Y	N	Y
		Atmos Energy Corporation (Mid-Tex)	TX	N	Y	N	Y
		Atmos Energy Corporation	VA	N	N	N	N
New Jersey Resources Corporation	NJR	New Jersey Natural Gas Company	NJ	Y	N	N	Y
NiSource Inc.	NI	Northern Indiana Public Service	IN	N	N	N	N
		Columbia Gas of Kentucky	KY	N	N	N	N
		Columbia Gas of Maryland	MD	Y	N	N	Y
		Columbia Gas of Massachusetts	MA	Y	N	N	Y
		Columbia Gas of Ohio	OH	N	N	Y	Y
		Columbia Gas of Pennsylvania	PA	N	N	N	N
		Columbia Gas of Virginia	VA	Y	N	N	Y
Northwest Natural Gas Company	NWN	Northwest Natural Gas Company	OR	Y	N	N	Y
		Northwest Natural Gas Company	WA	N	N	N	N
South Jersey Industries, Inc.	SJI	South Jersey Gas Company	NJ	Y	N	N	Y
Southwest Gas Corporation	SWX	Southwest Gas Corporation	AZ	Y	N	N	Y
		Southwest Gas Corporation	CA	Y	N	N	Y
		Southwest Gas Corporation	NV	Y	N	N	Y
Spire, Inc.	SR	Alabama Gas Company	AL	N	Y	N	Y
		Laclede Gas Company	MO	N	N	Y	Y
		Missouri Gas Energy	MO	N	N	Y	Y
		Mobile Gas Service Corporation	AL	N	Y	N	Y
		Willmut Gas & Oil Company	MS	N	N	N	N
Total Number of Jurisdictions (Y)							18
Total Number of Jurisdictions							27
Percent of Jurisdictions							66.7%

Notes:
[1] Source: American Gas Association, Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List, December 2016.
[2] Identifies companies with either a formula rate plan, revenue decoupling mechanism or straight fixed-variable rate design.

Montana-Dakota Utilities Co.

Selected Natural Gas Distribution Companies
Capital Structures as of March 31, 2017
$ millions

Company	Ticker	Short-Term Debt	%	Long-Term Debt	%	Preferred Stock	%	Common Equity	%	Total Capital	
Atmos Energy Corporation	ATO	$ 670.6	9.49%	$ 2,564.6	36.27%	-	0.00%	$ 3,834.9	54.24%	$ 7,070	1/
New Jersey Resources Corporation	NJR	237.9	9.12%	1,084.7	41.58%	-	0.00%	1,286.3	49.30%	$ 2,609	1/
NiSource Inc.	NI	1,514.2	12.51%	6,400.0	52.87%	-	0.00%	4,191.1	34.62%	$ 12,105	1/
Northwest Natural Gas Company	NWN	-	0.00%	719.7	45.14%	-	0.00%	874.6	54.86%	$ 1,594	1/
South Jersey Industries, Inc.	SJI	205.1	7.82%	1,111.2	42.34%	-	0.00%	1,307.9	49.84%	$ 2,624	1/
Southwest Gas Corporation	SWX	-	0.00%	1,590.2	48.11%	-	0.00%	1,715.4	51.89%	$ 3,306	1/
Spire Inc.	SR	567.4	12.97%	1,925.3	44.00%	-	0.00%	1,883.0	43.03%	$ 4,376	1/
Median			**9.12%**		**44.00%**		**0.00%**		**49.84%**		
MDU North Dakota Gas			5.97%		43.04%		0.00%		51.00%		2/

1/ Source: SNL Financial; quarterly data as of March 31, 2017.
2/ Source: Montana-Dakota Utilities Co. - North Dakota Natural Gas Operations

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

Before the North Dakota Public Service Commission

Case No. PU-17-__

Direct Testimony
of
Patrick C. Darras

Q. Please state your name and business address.

A. My name is Patrick C. Darras and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the Vice President of Operations for Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Co., Divisions of MDU Resources Group, Inc.

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I have executive responsibility for the development, coordination, and implementation of Company strategies and policies relative to all areas of distribution operations including pipeline integrity and safety along with employee safety.

Q. Please outline your educational and professional background.

A. I am a graduate of North Dakota State University with a Bachelor of Science Degree in Construction Engineering. I also hold an MBA along with a Master's Degree in Management both from the University of Mary. In June of 2014 I attended the Utility Executive Course at the University of Idaho.

I began my career with Montana-Dakota in 2002 as a gas engineer in Bismarck. I held that position for four years primarily working with the construction and service group in day to day operations. In 2006 I was moved into the role of Region Gas Superintendent where I was responsible for the overall gas engineering, construction, and service of the Dakota Heartland Region of Montana-Dakota. I worked in that capacity for two years and was then promoted to Region Director for Montana-Dakota's Dakota Heartland Region and Great Plains Natural Gas, Co. My responsibility in this role was oversight of all gas and electric operations for the Region. In January 2015 I accepted the promotion to Vice President of Operations for Montana-Dakota and Great Plains Natural Gas, Co. In this role I am responsible for gas and electric distribution operations and engineering across the five states of North Dakota, South Dakota, Montana, Wyoming, and Minnesota.

Prior to joining Montana-Dakota, I worked for a local industrial contractor specializing in refinery and power plant maintenance along with turn-key construction of industrial facilities such as refineries and food processing plants. I spent seven years with this group in various capacities in engineering, construction, and project management.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the Company's North Dakota natural gas operations along with our philosophy to be proactive and prudent operators in maintaining a safe and reliable natural gas system. I will discuss in further detail the following:

1. Montana-Dakota's natural gas operations
2. Montana-Dakota's gas organizational structure
3. Montana-Dakota's centralized support departments
4. Montana-Dakota's need for a System Safety and Integrity Program (SSIP)
5. Details and costs associated with the proposed SSIP

6. Need for an adjustment mechanism to recover costs associated with the SSIP.

Q. Please provide a summary of Montana-Dakota's natural gas operations in North Dakota.

A. Montana-Dakota provides natural gas service to approximately 109,000 customers in 74 communities, operating approximately 2,575 miles of distribution mains and approximately 110,000 service lines. The customer base is 86 percent residential customers and 14 percent commercial and industrial customers. As of December 31, 2016 the Company had 562 full and part time employees who live and work throughout the North Dakota gas and electric service area. Montana-Dakota's North Dakota service area is divided into two operating regions of which three operating districts fall under. Further detail is given on the structure of these regions later in my testimony. Montana-Dakota has gas service technicians and gas construction employees headquartered in 18 other North Dakota communities deemed strategic to the safe and reliable operation of the Company’s distribution system. There are also electric-only personnel in additional locations in North Dakota. Service technicians and construction employees in South Dakota and Montana also support operations in North Dakota communities close to the state border. A map of the gas distribution system in North Dakota is included as Exhibit No. ___(PCD-1).

Q. Please describe how Montana-Dakota's North Dakota natural gas operations are structured and managed in the field?

A. Field Operations for North Dakota are split into two "Regions" each led by a Region Director with employees located in a local region office along with district personnel that report to the Region Director. The two Regions and the respective Districts are as follows:

1. Dakota Heartland Region (Bismarck)
   - A. Minot District
   - B. Jamestown/Devils Lake District
   - C. Mobridge District (Linton)
2. Badlands Region (Dickinson)
   - A. Williston District
   - B. Glendive District (Beach)

Located in each Region office is a Construction Supervisor and a Field Operations Supervisor. Located in each District Office is a District

Manager and either a Construction Supervisor or a Field Operations Supervisor or both.

The Construction Supervisor is responsible for oversight of all construction including third party subcontractor work. Reporting directly to the Construction Supervisor are all gas construction personnel with Engineer Associates assigned to oversee subcontractors also reporting to the Construction Supervisor. All construction including new and replacement projects along with many maintenance activities are handled through this department.

The Field Operations Supervisor has oversight of the Service Department employees which includes all Service Technicians and District Representatives. These employees handle all service calls including first response to emergencies, meter installs, and all day-to day service activities.

Engineering duties in prior years were carried out by field engineers located at the region office. Montana-Dakota recently restructured the Company’s engineering group to report directly to the Director of Operations located in the General Office. More detail in regards to this restructuring is given later in my testimony.

There are currently 90 employees dedicated to Field Gas Operations, construction, and maintenance activities. Along with the gas only employees there are also 43 combination employees. These employees are located within the electric and gas combination areas including some smaller towns outside the Region and District Office locations. Combination employees handle the day-to-day activities of both electric and gas.

Q. Please describe the structure of the centralized Engineering and Operations Department and why this structure is integral to ensuring safe and reliable service is provided to customers.

A. Montana-Dakota's Centralized Engineering and Operations Department is located in the General Office in Bismarck. As mentioned earlier, this Department was recently restructured to include all field gas engineers.

The Centralized Engineering and Operations Department includes a Director of Engineering (Gas & Electric) and a Director of Operations. The Director of Operations' primary responsibility is the oversight and support of all gas operations. Reporting directly to the Director of Operations is as follows:

1. Manager of Standards and Compliance
2. Manager of Measurement
3. Manager of Field Operations
4. Supervisor of Engineering Services
5. Corrosion Lead Engineer

There are currently 23 employees that fall under the Centralized Engineering and Operations Department with personnel located in the General Office and in the Region or District offices.

Q. Please describe what other centralized functions support the field natural gas operations group.

A. *1. Safety & Training Department*

The safety of all personnel and customers is Montana-Dakota's top priority. The Safety and Training Department plays an integral part in this safety commitment and is the hub of all training for safety and operations, including training for employees necessary to be Operator Qualification compliant in accordance with Federal Pipeline Regulations. While oversight of the Operator Qualification plan rests in Operations, the administration of the program rests with the Safety and Technical Training Department.

2. Gas Supply

The principal function of Montana-Dakota's Centralized Gas Supply Department is to support the Company's operations by procuring, transporting, and storing natural gas in advance of delivery to the communities and locations served. This is done with consideration to cost and reliability of service. To accomplish this, the department remains apprised of industry trends, actively seeks least cost and most reliable commodity providers pursuant to a competitive proposal process, and continually reviews firm natural gas transportation services to ensure appropriate agreements are available.

The Gas Supply Department is also responsible for the scheduling and balancing activities for city gates associated with served communities. This activity allows for unbundled service customers to take delivery from a supplier other than Montana-Dakota. Accompanying this activity is the administration of customer contracts for those customers who receive service under an interruptible rate schedule. The department determines if and when interruption of service is required to maintain system integrity and deploys interruption plans to applicable personnel and customers.

For select large volume customers such as those receiving unbundled services or those receiving service under multiple rate schedules, the Gas Supply Department is responsible for the measurement information systems and resulting data. This data is used for billing, balancing activities, and forecasting.

3. Human Resources

The Human Resources Department has overall responsibility of Montana-Dakota's DOT Drug and Alcohol program along with the compliance of that program, including monitoring of contractor drug/alcohol programs. The Human Resources Department also manages compensation, benefits, recruitment and advises operations staff on employee relations issues including performance and discipline.

4. GIS

The GIS system and related environment is managed and maintained by the Enterprise GIS group within the centralized Enterprise Information Technology Department. The Enterprise GIS group partners with the Operation and Engineering field personnel to:

1. Perform editing/entry functions through the use of software tool sets within the GIS system. This process is often called

posting which is the editing/entry of new, modified, retired and/or abandoned facilities.

2. Perform editing/entry functions related to posting of landbase information.

3. GIS analysis for Operations, Engineering, Accounting, Tax and Regulatory departments within the company.

4. Analysis and reporting of GIS information related to federal and state regulatory requirements as well as other jurisdictional reporting requirements (tribal governments, cities, counties, taxing districts, etc.).

5. Maintain and manage one call boundaries which are submitted regularly to the various One Call Centers.

6. Maintain and manage the various GIS tools and systems. Support internal and field staff as they utilize these tools.

7. Maintain and manage the GIS system interfaces to other business systems such as PCAD mobile work management system, FCS Meter Reading system, Pipeline Inspection Manager, DOT Web Application compliance system, and the Electric Outage Management System.

The GIS system is used to track, manage and spatially represent the gas and electric facilities for Montana-Dakota. As facilities are installed, modified, retired, and/or abandoned their locations (spatial information such as latitude, longitude, survey points, etc.) as well as attribute information related to the assets (sizes, types, manufacturer, etc.) are managed in the GIS System. The GIS system also contains landbase information which references plats, subdivisions, streets, taxing districts as well as other public landmark reference information in order to provide referencing for these facilities. The GIS system represents the GIS information to employees and contractors utilizing tools such as mobile mapping software, desktop mapping software, and internal web viewable maps.

The software tools within GIS allow for analysis of the data contained within the system. Employees can use these tools to analyze: feet/miles of pipe by different attributes, numbers of valves installed, locations of facility by type, leak survey information, atmospheric corrosion survey information, and distribution integrity management. These are just a few of the many examples of analysis that can be performed. The GIS system also contains tools, which can be utilized during emergencies and other significant events, to show the impact of closing valves and squeezing lines. This tool set helps the Operations and Engineering staff make decisions about how to best handle these events and the impact of their decisions.

5. Customer Care Center

Montana-Dakota's customers have toll-free access to the Customer Service Center located in Meridian, Idaho, with a backup center in Bismarck, North Dakota, to place routine utility service requests and inquiries from 7:00 am to 7:00 pm local time, Monday through Friday and emergency calls on a 24-hour basis. A Scheduling Center, located in the Meridian, Idaho, facility, transmits electronic service orders to the mobile terminals placed in the Company's service and construction vehicle fleet. This network allows the Company to respond quickly to customer requests and emergency situations.

Q. Please describe the role the centralized Engineering and Operations Department takes in supporting natural gas operations in the field and ensuring Montana-Dakota's natural gas system is safe and reliable.

A. The Engineering and Operations Department has the primary responsibility for the oversight of all gas operations at Montana-Dakota. This group is responsible for overall Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) pipeline safety compliance, managing necessary requirements for compliance, damage prevention, and corrosion control. They also develop and manage the execution of maintenance and investment plans to provide a safe and reliable natural gas system.

Q. Please describe what role Montana-Dakota's North Dakota natural gas field operations group has in ensuring the natural gas system is safe and reliable.

A. The field operations group at Montana-Dakota is tasked with executing the plans laid out by the Engineering & Operations Department. Plans of system betterments, maintenance, and emergency response are the core responsibilities undertaken by field operations to keep the natural gas system safe and reliable. These plans include growth projects, replacement projects, maintenance activities, customer service (connects/disconnects), and emergency response.

Q. Please explain Montana-Dakota's approach to providing safe and reliable service to its North Dakota customers.

A. Montana-Dakota has been successful in finding efficiencies in serving North Dakota customers by continually reviewing its field operations without compromising its objective of providing safe and reliable natural gas service. Much of this has been possible due to the advancement of cost effective technology.

Montana-Dakota completed the implementation of Pragma CAD (PCAD). PCAD is a computer aided dispatching system for utility service orders, which replaced the previous system, Mobile Up. PCAD ensures that Montana-Dakota is able to maintain and improve upon the current level of customer service and pipeline data gathering.

We have also implemented a software solution called Pipeline Inspection Manager (PIM). PIM is designed to schedule, track, execute, and archive field data inspections for a variety of assets that fall under the jurisdiction of regulatory compliance guidelines. Montana-Dakota has implemented PIM for the monitoring of Company assets in corrosion inspection and annually inspected valves. It is the goal of the Engineering and Operations Department to continue to add additional required assets that fall under the regulatory compliance guidelines to the program such as regulator stations, odorization equipment, and tool calibration.

Montana-Dakota has always worked to provide a safe and reliable natural gas distribution system. In recent years, the predominant view, by both regulators and utilities, is to enhance data collection and analysis in order to further improve safety and reliability. The implementation of both PCAD and PIM has helped to automate, track, and manage distribution operations work flows. They have also allowed for the effective central sharing of data with the appropriate operations groups to make better evaluations and decisions to enhance the safety of customers, the general public, and employees.

Currently both of these systems automate operations and maintenance work orders that are then electronically dispatched to technicians and the resulting data is returned to the system and stored in a central database. The data captured within the system is then used to enhance and support the existing safety programs such as the Distribution Integrity Management Plan (DIMP), the Transmission Integrity Management Plan (TIMP), the Damage Prevention Program, the Public Awareness Plan, and Emergency Response Procedures.

Q. Please describe the challenges that are faced when operating a safe and reliable natural gas system.

A. Federal and State mandates require that minimum standards be met in regards to the operation of a natural gas system. In the recent past there has been an aggressive approach to further enhance system safety as a result of unfortunate pipeline incidents. Montana–Dakota works diligently, on a daily basis, to meet the federal and state safety standards and proactively evaluate its system to further reduce risk and ensure the public has a safe and reliable system.

Montana-Dakota and the natural gas industry in general are faced with an aging infrastructure. This aging infrastructure requires significant investment in order to maintain overall safety and reliability. Approximately 23 percent of Montana-Dakota's distribution mains and 24 percent of Montana-Dakota's service lines were installed prior to 1970. If you look at pre-1980 pipe, which would include pipe identified in the industry as Early Vintage Plastic Pipe these numbers climb significantly to approximately 44 percent and 46 percent, respectively. While there are other factors besides age in determining the overall integrity of a natural gas system, older vintage systems have demonstrated to be at higher risk than newer systems. This is simply because older facilities have been exposed to more threats and were often constructed without the benefits of today's materials and safety standards.

Federal Code changes related to natural gas pipelines along with a Call to Action issued by United States Secretary of Transportation, Ray LaHood, have resulted in the natural gas industry looking at a more proactive versus reactive approach to pipeline safety. As noted above, Montana-Dakota considers itself proactive in its approach to addressing pipeline safety by repairing and mitigating identified leaks, and identifying pipe and the vintage of pipe material that are prone to developing leaks at a higher rate than average and formulating a plan to mitigate those areas where the risks are higher.

However, this historical approach to integrity management is no longer sufficient. Prudent management of the integrity of the Company's pipeline system now requires a more aggressive approach, which will identify risks and require investment in measures to help mitigate those risks beyond the minimum code requirements. As a result, Montana–Dakota is requesting approval to implement a System Safety and Integrity

Program (SSIP) to enable the Company to further identify and mitigate natural gas system risks on a proactive basis.

Q. Please further describe specific challenges Montana-Dakota faces in operating a safe and reliable natural gas system based on the existing infrastructure.

A. As mentioned, Montana-Dakota is faced with an aging infrastructure. More specifically the Company's natural gas system includes Early Vintage Steel and Plastic Pipe, Low Pressure Systems (distribution pressure), and inside meter sets.

Montana-Dakota defines its Early Vintage Steel Pipe and Low Pressure Systems as steel pipe installed prior to the 1970’s. Although the practice was prevalent in those years, today’s installation practices and materials are much more resilient. For example, Low Pressure Systems for the most part were constructed with larger bore steel pipe for mains, from 4” – 12” in diameter, either welded or often times joined by mechanical couplings. Service lines again were constructed of steel pipe and connected to the main with a combination of welding and mechanical means. Along with Low Pressure Systems, the historical practice was to install meter sets inside buildings. While Montana-Dakota has worked towards removing inside meter sets, Montana-Dakota still has approximately 4,000 of these in our North Dakota system.

Montana-Dakota defines its Early Vintage Plastic Pipe as that plastic pipe installed prior to 1982. Falling under the Early Vintage Plastic Pipe definition is a pipe type called “Aldyl A”. The National Transportation Safety Board has advised that there is a potential susceptibility of plastic pipe installed between 1960 and the early 1980’s to premature failure due to brittle-like cracking. Montana-Dakota does have this early vintage plastic Aldyl A pipe in its system.

Q. Has Montana-Dakota made investments in North Dakota to the existing gas distribution system to enhance the safety and reliability in the system?

A. Yes, the Company has made significant investments in natural gas distribution infrastructure, primarily related to the replacement of existing facilities and the investment of new border stations and loop lines, along with the investment in the software systems mentioned above. The investments in the software systems have contributed to the Company’s success in controlling O&M costs per customer, while the investments in infrastructure allow for more efficient, safe, and reliable system operations.

The replacement projects improve safety and reliability by replacing older pipe with new pipe and by re-engineering the system when needed. Currently replacement projects are selected based on prioritizing risks and then choosing the projects that will result in the greatest safety and reliability improvements. As discussed later, the process of selecting areas of the system for replacements has become more standardized and data-driven with the implementation of the Distribution Integrity Management Plan (DIMP).

In addition, the investment in border stations and loop lines improves safety and reliability by providing the customers with a secondary feed to their premises. During emergencies, this allows for quicker restoration of services and potentially no disruption of service.

Q. Please explain the need for Montana-Dakota to develop and implement a structured System Safety and Integrity Program (SSIP).

A. The natural gas industry is undergoing significant changes in the way we approach pipeline safety, integrity, and reliability. Integrity programs are intended to guide utilities to better understand threats associated with their systems and the conditions of their pipelines so that they can proactively address the risks of their natural gas operations.

At Montana-Dakota we recognized the need for better processes to collect system data and analyze the information to make more informed decisions in regards to maintenance and capital investments needed to provide a safe and reliable system. With recent system improvements such as our PIM program along with a centralized approach to the management of data collection and the corresponding process to address risks gathered from that data collection, Montana-Dakota has positioned itself to be proactive in pipeline safety improvements.

The data gathered to date, along with the opinions of subject matter experts within the Company and throughout the industry, points to the need for Montana-Dakota to implement a more systematic pipeline safety and integrity process than has been utilized to date in managing the Company’s pipeline safety program. Where risks are identified, we must devote the time and resources needed to help mitigate future problems with the natural gas system. We realize that our infrastructure is aging and that expectations in regards to the safety and reliability of pipelines are being raised. Recent fatal incidents from natural gas pipeline failures such as in San Bruno, California and Allentown, Pennsylvania have appropriately heightened these expectations.

Montana-Dakota strives to be a leader in the industry when it comes to pipeline safety. A single incident is one too many. The goal of a systematic proactive approach of a System Safety and Integrity Program or SSIP is to better provide the safe system our customers and the public expect and deserve.

Q. What is Montana-Dakota proposing in regards to the SSIP?

A. As part of the SSIP, Montana-Dakota is proposing a structured replacement plan for its Early Vintage Steel and Plastic Pipe Systems as described earlier. While our DIMP Model will remain dynamic due to changing risks and regulations, the initial intent for the Company is to focus the SSIP on the replacement of systems in these two categories which have been identified as higher risks within the Company's current DIMP model. In order to fund this more proactive replacement program and to avoid the need for frequent rate cases, Montana-Dakota is proposing a SSIP adjustment mechanism as more fully explained by Mr. Jacobson and Ms. Bosch.

Q. What types of pipe will be replaced as part of the SSIP program?

A. Early Vintage Steel Pipe – Pipe falling under this category will be steel mains, associated fittings, and services installed prior to 1970. Along with the pipe replacement, inside meter sets connected to the corresponding services will also be removed to a safer outside location.

Early Vintage Plastic Pipe – Pipe falling under this category will be pre 1982 Aldyl A plastic pipe.

Q. How will Montana-Dakota determine what Early Vintage Steel Pipe and Early Vintage Plastic Pipe to replace each year?

A. In the past, Montana-Dakota replaced pipe based on the identified highest risks through either the DIMP model or subject matter expert recommendations. Often times these projects were coordinated with city or state street projects to optimize efficiency gains recognized with these entities. For example if there was a city street rebuild, Montana-Dakota would develop a plan to not only replace the early vintage pipe associated with that specific street project but expand beyond the boundaries to take advantage of efficiencies gained by having staff or contractors on site. Often times we were able to replace higher risk pipe while saving costs on mobilization, street and sidewalk repair, right of way damage, etc. This process was effective but was more of a reactive approach.

As has been mentioned, the SSIP will be a more proactive and accelerated approach to pipeline integrity replacement projects.

Replacement projects will be prioritized based on the highest risk systems and areas identified in the Company's DIMP Model. This process will allow engineers to take a holistic approach in determining areas not only with identified leaks but also with the highest risk pipe that can be removed. This will include the removal of materials prone to leaks and potential failure. Efficiency gains on system design will also be a factor impacting which areas to replace. Our actions will be driven by data analysis and verified with subject matter experts.

The SSIP will be dynamic in that it could change annually based on new findings, data trends, regulations, etc. We will make adjustments to target specific pipeline vintage and components as identified by our DIMP Model. Through improvements in data collection and technology we will continue to promote more efficient planning and execution of our work to provide a safe, reliable, and affordable service to our customers.

As part of the SSIP adjustment mechanism, Montana-Dakota will also provide the Commission with an annual plan for the identified replacement projects as well as cost updates for projects previously approved for recovery under the SSIP adjustment mechanism.

Q. Would you elaborate on the Pipeline and Hazardous Materials Safety Administration's DIMP rule and how Montana-Dakota has responded to this regulation?

A. DIMP is a Federal requirement issued as Subpart P of 49 CFR 192 pertaining to all gas distribution system operators. DIMP requires operators to know the make-up of their distribution system. The objective of the plan is to develop a model to assist in determining which areas of the gas distribution system to focus operation, maintenance, and repair efforts and resources due to known or predicted threats to the distribution system.

The model assesses eight different threat categories: Corrosion, Natural Forces, Equipment Failure, Excavation, Incorrect Operation, Joint Failure, Outside Force, and Other all equally weighted.

A detailed geographical information system (GIS) map, with every piece or component that makes up the gas distribution system, both above and below ground, and with as much information about each piece as is available is used as the basis of the model. Scores for various factors were determined by a group of subject matter experts including engineers and field technicians.

The model sets a 50 foot by 50 foot grid to analyze all components. Each grid is then analyzed by eight individual sub-models with up to 150 calculations in each sub-model. This in turn produces a very comprehensive look at the entire system with each component compared equally to the others across the entire four state operating areas. In North Dakota, 23.4 million feet of pipe was analyzed with approximately 5.16 million calculations to support the risk model.

The results obtained from the DIMP modeling are consistent with what it was expected to produce by subject matter experts. The components that score the highest are generally located near district regulator stations where there are concentrations of different components such as fittings and valves, above ground piping, and elevated pressures.

The DIMP results are used as an operational tool to aid in directing resources to reduce pipeline risks. The results are consistently analyzed to determine accelerated actions to the pipeline so that changes to resource planning and budgeting can be made to carry out the reduction in risks from pipeline threats.

Q. What will be involved in the SSIP in 2017 and 2018 proposed to be recovered as part of this rate case?

A. Several projects included in this rate case have been identified as projects that would fall under the SSIP. Examples of these projects are as follows:

1. Bismarck, ND – 13th St – Replacement of Early Vintage Steel and Plastic pipe and relocating inside meter sets.
2. Williston, ND – 54th St – Replacement of 1950's vintage steel main and services. This project will eliminate approximately a dozen leaks, address local Cathodic Protection (CP) issues, along with converting two separate pressure systems into one, resulting in a more efficient system allowing for more uniform operation.
3. Richardton, ND – Replacement of Bare Steel (CP) issues and Low Pressure Steel mains and services along with relocating inside meter sets.
4. New Salem, ND - Replacement of Low Pressure Steel mains and services along with relocating inside meter sets.
5. Taylor, ND - Replacement of Low Pressure Steel mains and services along with relocating inside meter sets.

Q. What is Montana-Dakota planning for the SSIP program in years 2019-2021?

A. Montana-Dakota plans a structured approach to the replacement of approximately 80,000 feet of main and 1,000 services per year over the years 2019 through 2021 requiring estimated annual funding of approximately $6 million in addition to the $7.6 million investment in SSIP related projects included in this rate case.

Q. Describe how Montana-Dakota would implement and manage its proposed SSIP.

A. Implementation of the System Safety and Integrity Program will utilize the company DIMP Model to identify key risks associated with Montana-Dakota's natural gas system. A sub team from the Centralized Engineering Department referred to as the Engineering Studies Group will identify, assess, prioritize, develop, and schedule a replacement plan for high-risk infrastructure. The Engineering Studies Group will utilize a systematic replacement design process for Early Vintage Steel and Plastic Pipe. Replacement design process format will include the following:

1. Location
    - City Name, general work location, class location, etc.

2. Risk Features

- Early Vintage Steel Main Footages
- Pre-1982 Early Vintage Plastic Main Footages
- Post-1982 Early Vintage Plastic Main Footages
- Service Line count within high risk area
- Number of Inside Meters to be relocated
- Leak History

3. Estimated Costs

- An itemized unit format will be used to calculate a high-level cost estimate based on above-mentioned risk features

4. Replacement Plan Support Documentation

- Detailed Scope of Work
- Develop and complete replacement plan documents (maps, permits, applications, work orders, customer letters, etc.)
- Create a detailed construction replacement sequence

5. Management of Physical Replacement

- Identified replacement(s) will be completed by Montana-Dakota, or
- Third Party Contractors under Montana-Dakota's supervision

The above information will also be provided on an annual basis in support of the Company's proposed SSIP adjustment mechanism for the ensuing year along with actual costs provided for the prior year.

Q. Does the SSIP address a safety and reliability concern?

A. Yes it does. Both the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the National Transportation Safety Board (NTSB) have expressed concern in regards to the continued operation of aging natural gas infrastructure along with certain plastic pipe installed between 1960 and the early 1980's which had been previously approved for the natural gas industry. The potential vulnerability of older plastic pipe to brittle-like cracking continues to be a concern for the natural gas industry and both PHMSA and the NTSB have advocated for removal of these facilities.

As mentioned earlier, Montana-Dakota places the safety and reliability of its natural gas system as a top priority. The removal of Early Vintage Steel and Early Vintage Plastic pipe will improve safety and reliability by reducing leaks and system interruptions for customers. As these early vintage materials are replaced, system complexities can be reduced by the standardization of system pressures, pipe sizes, and design processes such as the looping of systems. Standardization of pressures will allow for the removal of Low Pressure stations and improved sectionalizing plans. Looping of systems eliminates localized single feed areas potentially reducing service interruptions to customers. Overall, the system safety and reliability is improved; therefore, the SSIP and recovery of the associated costs through an adjustment mechanism is in the public interest.

The SSIP, along with the certainty of cost recovery under the SSIP Adjustment Mechanism, may allow Montana-Dakota to enter into longer, multi-year contracts with third party contractors. Past experience has shown that multi-year contracts often times provide for better pricing and enhance the planning and scheduling of our overall construction program.

Finally, the low natural gas prices available to customers today provides a good opportunity to address the pipeline replacement projects proposed to be recovered through the SSIP adjustment mechanism.

Q. Does the SSIP address all pipeline replacement projects?

A. No, it does not. Certain pipeline replacements remain as part of normal day-to-day business activity. Montana-Dakota routinely replaces pipelines based on safety, engineering review, special city/county or public works projects, developer projects, franchise commitments and obligations, and system improvement or supply concerns.

Examples of projects identified for 2017 and 2018 that will fall under this category are:

1. Downtown Minot, ND – Main and service replacement driven by the City of Minot's water and sewer project. This project is eliminating bare/coated protected steel and several inside meter sets.
2. Minot Floodwall Project - Main and service line relocation as required by the City of Minot's flood wall refurbishment project.
3. Devils Lake Levee/Road Project - Main relocation due to City of Devils Lake's levee/road project and line interference.

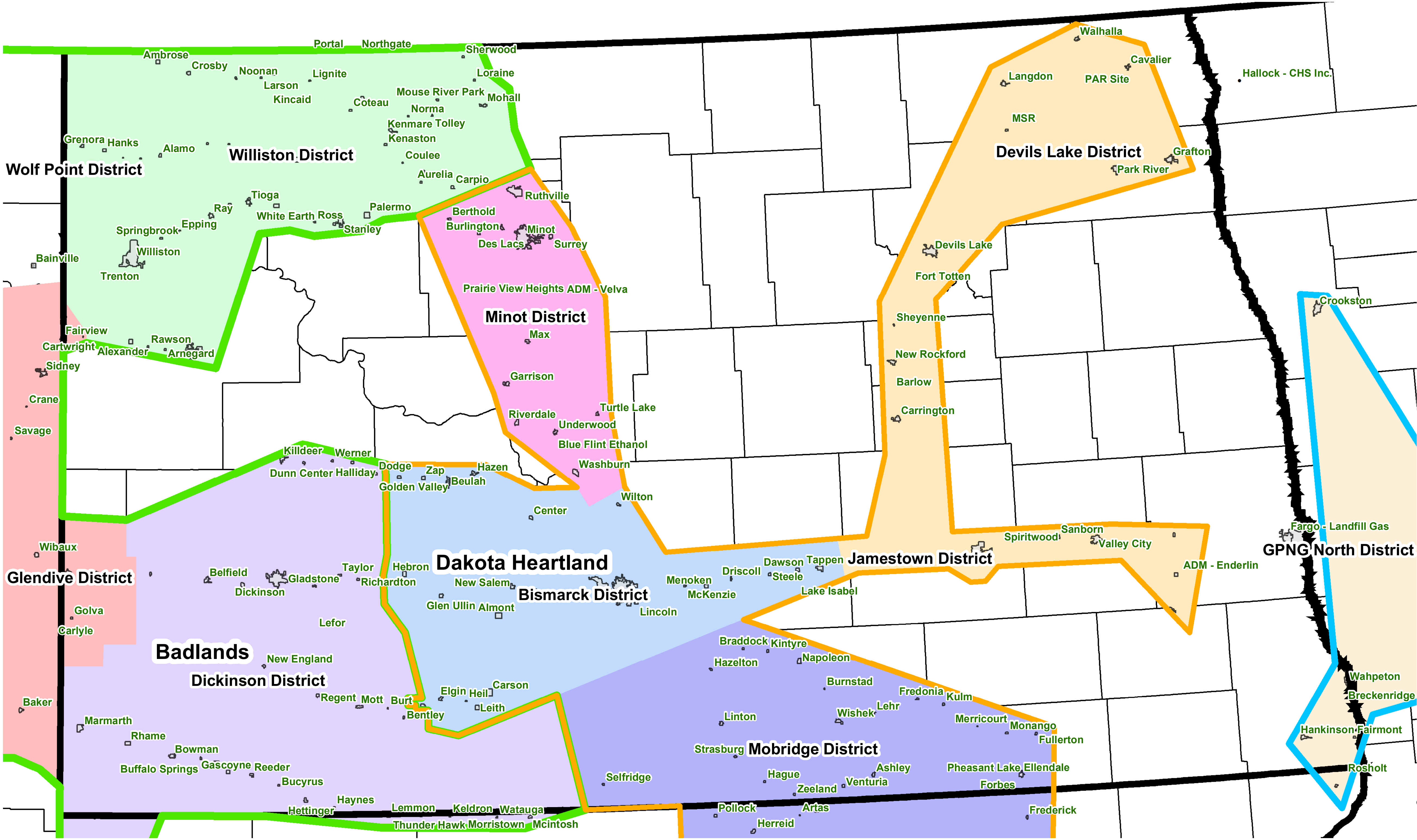
The cost of these types of projects will not be included in the SSIP adjustment mechanism as they are projects that are required because of work being done by the noted communities. While the replacement projects will enhance the safety and reliability of the system, the projects were not identified as a high risk by the Company's DIMP model.

Q. Is Montana-Dakota's natural gas system safe today?

A. Yes, it is. While there will always be a certain amount of risk associated with the operation of a natural gas system, it is our responsibility to identify those risks, monitor those risks, and mitigate them when appropriate. Overall Montana-Dakota's system has proven to be safe and reliable; however, we must remain vigilant in the operation of our system as past success does not guarantee the same future results.

Q. Does this complete your direct testimony?

A. Yes, it does.



Case No. PU-17-___
Exhibit No. ___ (PCD-1)
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MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the North Dakota Public Service Commission

Case No. PU-17-___

Direct Testimony
of
Tammy J. Nygard

Q. Please state your name and business address.

A. My name is Tammy J. Nygard, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the Controller for Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Co., Divisions of MDU Resources Group, Inc. I am also the Controller of Cascade Natural Gas Corporation and Intermountain Gas Company; subsidiaries of MDU Resources Group, Inc.

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I am responsible for providing leadership and management of the accounting and the financial forecasting/planning functions, including the analysis and reporting of all financial transactions for Montana-Dakota, Great Plains, Cascade, and Intermountain.

Q. Would you please outline your educational and professional background?

A. I graduated from the University of Mary with a Bachelor of Science degree in Accounting and Computer Information Systems. I have over 15 years of experience in the utility industry. During my tenure with the MDU Utilities Group, I have held positions of increasing responsibility, including Financial Analyst for Montana-Dakota, Director of Accounting and Finance for Cascade, and now as MDU Utilities Group Controller.

Q. What is the purpose of your testimony in this proceeding?

A. I am responsible for presenting Statement D.

Q. Was this statement and the data contained therein prepared by you or under your supervision?

A. Yes, it was.

Q. Is it true to the best of your knowledge and belief?

A. Yes, it is.

Q. Would you please explain Statement D?

A. Statement D shows the utility capital structure of Montana-Dakota for the twelve months ended December 31, 2016 and the projected capital structure for 2017 and 2018. Statement D includes the associated costs of debt, preferred stock and common equity. This capital structure and the associated costs serve as the basis for the overall rate of return requested by Montana-Dakota in this rate filing of 7.542 percent. The basis for the requested 10.00 percent return on common equity contained within the overall requested rate of return is supported by the testimony of Dr. J. Stephen Gaske.

Page 1 of Statement D summarizes the utility capital structure and the related utility costs of capital at December 31, 2016 and the projected capital structure and the related utility costs of capital for 2017 and 2018. As shown on page 1, the components of the 2018 projected overall annual rate of return, which are used by Mr. Jacobson to calculate the revenue requirement, are:

	Weighted Cost of Capital
Long Term Debt	2.273%
Short Term Debt	0.169%
Preferred Stock	0.000%
Common Equity	5.100%
Required Rate of Return	7.542%

Q. Are there recent changes to the capital structure?

A. Yes. On April 1, 2017 Montana-Dakota redeemed all preferred stock issued and outstanding. Preferred stock comprised about 1.1 percent of the capital structure in 2016 and was replaced with lower cost long term debt. The redemption reduces the administrative burden associated with the preferred stock and, at the same time, reduces the overall cost of capital. The Company did incur a redemption premium to redeem the preferred stock and has deferred the costs of the redemption. As further discussed in the testimony of Mr. Jacobson, Montana-Dakota proposes to include those costs, net of deferred income taxes, in the rate base similar to debt redemption costs. The inclusion of deferred preferred stock redemption charges in rate base continues to show a net present value benefit to customers.

Q. Was it prudent to redeem the preferred stock?

A. Yes. By redeeming preferred stock, Montana-Dakota reduced its financing costs. The preferred stock had dividend rates of 4.5% and 4.7%. This was replaced with the fifteen year long-term debt issuance issued in March 2017 at an interest rate of 3.36%. The result of the redemption is a lower overall cost of capital. An analysis has been prepared which demonstrates the overall net benefit of the redemption, inclusive of the rate base impact, is beneficial to customers.

Q. How does the Company finance its natural gas utility operations and determine the amount of common equity, debt and preferred stock to be included in its capital structure?

A. As a regulated public utility, the Company has a duty and obligation to provide safe and reliable service to its customers across its service territory while prudently balancing cost and risk. In order to fulfill its service obligations, the Company has made significant capital expenditures for new plant investment throughout its service territory, especially in mains and services. These new investments also have associated operating and maintenance costs. Through its financial planning process, the Company determines the amounts of necessary financing required to support these activities. Montana-Dakota finances its operations with a target of 50 percent common equity. Capital expenditure investments are financed through a mix of internally generated funds, the utilization of the Company's short-term credit line and the issuance of additional debt and common equity financing as required to maintain targeted capital ratios and finance the combined utility operations.

The Company obtained $10.0 million of additional common equity in 2016. In addition, the Company expects to receive approximately $25.0

million of common equity during 2017 in order to achieve and maintain the targeted capital structure.

In 2016, the Company is issued a $100.0 million private placement of unsecured senior notes with $40.0 million of that amount drawn in 2016 and the balance of $60.0 million delayed until March 2017. $50.0 million of senior notes were paid off in September 2016.

Q. What does Statement D, Schedule D-1 show?

A. Page 1 is a summary showing the Company's long-term debt at December 31, 2016 and associated cost of debt, and it shows the projected long-term debt and associated costs for 2017 and 2018. Page 2 shows the cost and the debt balance by issue at December 31, 2016. Page 3 shows the projected cost and the debt balance by issue at December 31, 2017 and page 4 shows the projected cost and the debt balance by issue at December 31, 2018.

Q. How did you derive the projected cost of debt for 2017 and 2018?

A. The projected cost of debt for 2017 and 2018 is based upon the yield-to-maturity of each debt issue outstanding.

Q. Would you please describe Statement D, Schedule D-1, page 5 and explain the amortization method utilized?

A. Page 5 reflects the annual amortization of the costs associated with the redemption of long-term debt. For this proceeding, the amortization has been computed on a straight-line basis over the remaining life of the issues. The Company uses the same calculation for accounting purposes.

Q. Would you please describe Statement D, Schedule D-1, page 6?

A. Page 6 presents the twelve-month average short-term debt balance for 2016 and projected 2017 and 2018 as well as the average cost of short-term debt. A twelve-month average of short-term debt is used in the cost of capital calculation to reflect the seasonality in the short-term debt balance. Short-term debt is historically at or near its peak in December and the twelve-month average calculation is more reflective of the borrowing level than a year-end balance.

Q. What does Statement D, Schedule D-2 show?

A. Page 1 presents the preferred stock balances and weighted cost at December 31, 2016 along with the redemption in the second quarter of 2017. Pages 2 sets forth the various preferred stock issues outstanding at December 31, 2016 and page 3 presents the same information indicating no preferred stock remains outstanding at December 31, 2017.

Q. Statement D, Schedule D-2 shows preferred stock redeemed in 2017. When was the preferred stock redeemed?

A. As noted previously in my testimony, on March 1, 2017, the Company provided notice of its intent to redeem all outstanding shares of preferred stock. Effective April 1, 2017, all outstanding preferred shares were redeemed.

Q. What does Statement D, Schedule D-3 show?

A. The schedule presents the common equity balance at December 31, 2016 and the projected balance for December 31, 2017 and December 31, 2018 reflecting the projected activity in the balance.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Application of	)	Case No. PU-17-__
MONTANA-DAKOTA UTILITIES CO.,	)	
a Division of MDU Resources Group,	)	
Inc., for Authority to Establish	)	
Increased Rates for Natural Gas	)	
Service		

DIRECT TESTIMONY AND EXHIBITS

OF

EARL M. ROBINSON

On The Subject of Depreciation

TABLE OF CONTENTS

I. WITNESS INTRODUCTION

Q1. Please state your name, occupation and business address.

A. My name is Earl M. Robinson. I am a Principal of AUS Consultants. AUS Consultants is a consulting firm specializing in preparing various financial studies including depreciation, valuation, revenue requirements, cost of service, and other analysis and studies for the utility industry and numerous other entities. AUS Consultants provides a wide spectrum of consulting services through its various practices. My office is located at 792 Old Highway 66, Suite 200, Tijeras, NM 87059.

Q2. Have you prepared an appendix which contains your qualifications and experience?

A. Yes. Appendix A to my direct testimony contains a summary of my qualifications and experience.

II. PURPOSE OF TESTIMONY

Q3. What is the purpose of your testimony?

A. The purpose of my testimony is to set forth the results of my depreciation review and analysis of the plant in service of Montana-Dakota Utilities Co.-Gas Division and Common Plant ("Company") which was conducted in the process of preparing depreciation studies of the Company's gas and common plant assets as of December 31, 2015 and December 31, 2014, respectively. Reports of my review and analyses are contained in Exhibit No. ___(EMR-1), titled "Montana-Dakota Utilities Co-Gas Division Depreciation Study as of December 31, 2015" and Exhibit No. (EMR-2), the "Montana-Dakota Utilities Co.-Common Plant Depreciation Study as of December 31, 2014". In preparing the report, I investigated and analyzed the Company's historical plant data and reviewed the Company's past experience and future expectations to determine the remaining lives of the Company's gas and common plant assets. The studies utilized the resulting remaining lives, the results of a salvage analysis, the Company's vintaged plant in service investment and depreciation reserve to develop recommended average remaining life depreciation rates and depreciation expense related to the Company's plant in service.

III. BACKGROUND

Q4. How is depreciation defined?

A. Depreciation is defined in the 1996 NARUC "Public Utility Depreciation Practices" publication as follows: "Depreciation**,** as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities."

Q5. Why is depreciation important to the revenue requirements of a utility company?

A. Depreciation is important because, as the above definition describes, depreciation expense enables a company to recover in a timely manner the capital costs related to its plant in service benefiting the company's customers. Appropriate depreciation rates will allow recovery of a company's investments in depreciable assets over a life that provides for full recovery of the investments, less net salvage. Without the appropriate recovery of depreciation costs, the Company ultimately will not be able to meet its financial obligations related to the continued provision of service to customers. Furthermore, the inclusion of the appropriate level of depreciation recovery in revenue requirements serves to reduce overall costs (total of depreciation and return) to customers as opposed to a situation where an inadequate level of annual depreciation expense is currently being provided in rates.

IV. DEPRECIATION STUDY OVERVIEW

Q6. What is your professional opinion with regard to the results of the depreciation study that you performed?

A. In my opinion, the proposed depreciation rates resulting from the completed comprehensive depreciation study are reasonable and appropriate given that they incorporate the service life and net salvage parameters currently anticipated for each of the Company's property group investments over their average remaining lives.

Q7. What steps were involved in preparing the service life and salvage database that you utilized?

A. My comprehensive depreciation analyses included a detailed analysis of the Company's fixed capital books and records through December 31, 2015 and December 31, 2014 for the gas and common plant in service. The Company's historical investment cost records for each account have been assembled into a depreciation database upon which detailed service life and salvage analysis were performed using standard depreciation procedures.

Q8. What is the purpose of the historical database?

A. The historical service life and net salvage data is a basic depreciation study tool that is assembled to prepare a depreciation study. The historical database is used to make assessments and judgments concerning the service life and salvage factors that have actually been achieved, and (along with information relative to current and prospective factors) to determine the appropriate future lives over which to recover the Company's depreciable fixed capital investments. In accordance with this standard depreciation analysis, the Company's depreciation database compiled through December 31, 2015 (gas) and December 31, 2014 (common), which contains detailed vintage level information, was used to develop observed life tables. The development of the observed life tables from the historical information was completed by grouping like aged investments within each property category and identifying the level of retirements that occur through each successive age to develop the applicable observed life tables. The resulting observed lives were then fitted to standard Iowa Curves to estimate each property group's historically achieved average service life.

Likewise, the net salvage database was used as a basis to identify historical experience and trends and to determine each property group's recommended net salvage factors. This was accomplished by preparing various three year rolling band analyses of salvage components as well as a forecast based on the Company's historical salvage experience.

Q9. In the preparation of the depreciation study, have you utilized information from additional sources when estimating service life and salvage parameters?

A. Yes. In addition to the historical data obtained from the Company's books and records, information was obtained from Company personnel relative to current operations and future expectations with respect to depreciation. Discussions were held with Company planning and operations management. In addition, physical inspections were also conducted of various representative sites of the Company's operating property.

Q10. Please briefly describe the information included in the depreciation study reports.

Each of the depreciation reports are divided into seven (7) sections. Section 1 of the report contains a brief narrative summary of the respective report. Two key portions of each of the reports are Sections 2 and 4. Section 2 includes the summary schedules listing the present and proposed depreciation rates for each depreciable property group and other depreciation rate development schedules. Section 4 contains a narrative description of the factors considered in selecting service life parameters for the Company's property. The various other sections of the report contain detailed information and/or documentation supporting the schedules contained in Sections 2 and 4. In addition, Section 5 is the graphical presentation of the average service life analysis, Section 6 is the detailed Average Remaining Life calculations, and Section 7 is detailed Net Salvage analysis schedules.

Q11. What was the source of the data utilized as a basis for determining the depreciation rates?

A. As previously discussed, all of the historical data utilized in the course of performing the detailed service life and salvage study was obtained from the Company's books and records. Historical vintaged data (additions, retirements, adjustments, and balances) were obtained for each depreciable property group.

Q12. Are there standard methods utilized to complete a service life analysis of a company's historical property investments?

A. Yes. As discussed in Section 3 of the depreciation study report as well as later in this testimony, the two most common methods are the Retirement Rate Method and the Simulated Plant Record Method. The method chosen to study a company's historical data is dependent upon whether aged or un-aged data is available. If specific aged data is available, the Retirement Rate Method is used. If only un-aged data is available, the Simulated Plant Record Method is used.

Q13. Were your studies prepared utilizing one of these accepted standard methods?

A. Yes.

V. METHODS, PROCEDURES & TECHNIQUES

Q14. Please describe the depreciation methods, procedures, and techniques commonly utilized to develop depreciation rates for utility property.

A. Inherent in all depreciation calculations is an overall method, such as the Straight Line Method (which is the most widely used approach within the utility industry) to depreciate property. Other methods available to develop average service lives and depreciation rates are accelerated and/or deferral approaches such as the Sum of the Years Digits Method or Sinking Fund Method.

In addition, there are several procedures that can be used to arrange or group property by sub-groups of vintages to develop applicable service lives. These procedures include the Broad Group, the Equal Life Group and other procedures. Due to the existence of very large quantities of property units within utility operating property, utility property is typically grouped into homogeneous categories as opposed to being depreciated on an individual unit basis. While the Equal Life Group procedure is viewed as being the more definitive procedure for identifying the life characteristics of utility property and as a basis for developing service lives and depreciation rates, the Broad Group Procedure is more widely utilized throughout the utility industry by regulatory commissions as a basis for depreciation rates. My comments on the Equal Life Group procedure are discussed later in my testimony.

The distinction between the two procedures is in the manner in which recovery of the cost is achieved. Under the Broad Group Procedure, the useful life and resulting depreciation rate is based upon the overall average life of all of the property within the group, while under the Equal Life Group Procedure, the useful life and resulting depreciation rate is based upon separately recovering the investment in each equal life group within the property category over the actual life of the property in that group.

A brief example (with a property group that has three units/three equal life groups of like property) will demonstrate the difference between the two procedures. The example incorporates the assumption that unit No. 1 (or equal life group of property) will retire after one year, unit No. 2 (or equal life group) will retire after two years, and Unit No. 3 (or equal life group) will retire after three years. Accordingly, the average life of all three (groups) is two (2) years (1+2+3)÷3. Under the Broad Group Procedure, the average useful life and resulting depreciation rate is calculated based upon the two (2) year average life. The resulting annual depreciation rates would be fifty (50) percent in every year. Conversely, under the Equal Life Group Procedure, each year's average life and resulting depreciation rate is calculated by using the period of time during which the portion of the property group remains in service. Since unit No. 1 (or that portion of the account) was retired from service after one year, the entire investment for that property is recovered over one (1) year. Likewise, since unit No. 2 (or that portion of the account) will have a service life of two years, the recovery of that portion of the account will occur over two years. Lastly, unit No. 3 (or that portion of the account) is recovered over three years. Hence, the useful average life for the property group in the first year is 1.64 years and the first year's annual depreciation rate is 61.11 percent. In the second year, the useful average life of the surviving group is 2.4 years and the second year's depreciation rate drops to 41.67 percent. This occurs because during the first year, unit No. 1 (or that portion of the account) was fully recovered. Likewise, in year three the useful life of the surviving group is 3 years and the depreciation rate further drops to 33.33 percent. See the following Table EMR-1 (BG and ELG).

		BG Average Life Calculation				BG Depreciation Rate Calculation			
Year		**Investment**	**Recovery Period (Yrs)**	**ASL (Years)**	**Weight**	**Investment**	**Recovery Period (Yrs)**	**Annual Rate-%**	**Recovery Amount**
1	Group # 1	300	2		150	300	2		150
	Group # 2	300	2		150	300	2		150
	Group # 3	300	2		150	300	2		150
	Total	900		2.00	450	900		50.00%	450
2	Group # 1	0	0		0	0	0		0
	Group # 2	300	2		150	300	2		150
	Group # 3	300	2		150	300	2		150
	Total	600		2.00	300	600		50.00%	300
3	Group # 1	0	0		0	0	0		0
	Group # 2	0	0		0	0	0		0
	Group # 3	300	2		150	300	2		150
	Total	300		2.00	150	300		50.00%	150
Grand Total		1,800		2.00	900	1,800		50.00%	900

		ELG Average Life Calculation				ELG Depreciation Rate Calculation			
Year		**Investment**	**Recovery Period (Yrs)**	**ASL (Years)**	**Weight**	**Investment**	**Recovery Period (Yrs)**	**Annual Rate-%**	**Recovery Amount**
1	Group # 1	300	1		300	300	1		300
	Group # 2	300	2		150	300	2		150
	Group # 3	300	3		100	300	3		100
	Total	900		1.64	550	900		61.11%	550
2	Group # 1	0	0		0	0	0		0
	Group # 2	300	2		150	300	2		150
	Group # 3	300	3		100	300	3		100
	Total	600		2.40	250	600		41.67%	250
3	Group # 1	0	0		0	0	0		0
	Group # 2	0	0		0	0	0		0
	Group # 3	300	3		100	300	3		100
	Total	300		3.00	100	300		33.33%	100
Grand Total		1,800		2.00	900	1,800		50.00%	900

Finally, the depreciable investment needs to be recovered over a defined period of time (through use of a technique), such as the Whole Life or Average Remaining Life of the property group. The distinction between the Whole Life and Average Remaining Life Techniques is that under the Whole Life Technique, the depreciation rate is based on a snapshot and determines the recovery of the investment and average net salvage over the average service life of the property group for that moment in time. The Whole Life technique requires either frequent updates to keep the "snapshot" current or the use of an artificial deferred account that holds "excess" or "deficient" depreciation reserves. In comparison, under the Average Remaining Life Technique, the resulting annual depreciation rate incorporates the recovery of the investment (and future net salvage) less any recovery experienced to date over the average remaining life of the property group. The Average Remaining Life Technique is clearly superior in that it incorporates all of the current and future cost components in setting the proposed annual depreciation rate as opposed to only some of the current and future cost components as is the case with the Whole Life Technique. This means that any changes that occur in between depreciation studies are automatically trued-up in the subsequent study. No artificial deferral account needs to be established to accomplish such a true-up.

The depreciation methods, procedures, and techniques can be used interchangeably. For example, one could use the Straight Line Method with the Broad Group Procedure and the Average Remaining Life Technique, or the

Straight Line Method with the Equal Life Group Procedure and Average Remaining Life Technique, or combinations thereof.

Q15. Which of these methods, procedures and techniques did you use in your depreciation studies?

A. The depreciation rates set forth in my depreciation study reports were developed utilizing the Straight Line Method, the Broad Group Procedure, and the Average Remaining Life Technique.

Q16. Why did you utilize this method, procedure and technique?

A. The Straight Line Method is widely understood, recognized, and utilized almost exclusively for depreciating utility property.

The Broad Group Procedure recovers the Company's investments over the average period of time in which the property is providing service to the Company's customers. While I have used the Equal Life Group procedure in other studies, I used the Broad Group Procedure in this study because it is consistent with depreciation methods and procedures generally accepted by regulatory Commissions and is the approach underlying the Company's current depreciation rates.

Finally, the amount of annual depreciation must be based upon the productive life over which the un-depreciated capital investment is recovered (the Average Remaining Life Technique). The utilization of the Average Remaining Life Technique to develop the applicable annual depreciation expense (over the average remaining life) assures that the Company's property investment is fully recovered over the useful life of the property, and that inter-generational inequities are avoided as current and future customers will pay their fair share of depreciation expense. The determination of the productive remaining life for each property group relies on a study of both past experience and future expectations and develops the appropriate total life and applicable depreciation rates for each of the Company’s property groups. The Average Remaining Life Technique incorporates all of the Company's fixed capital cost components, thereby better assuring full recovery of the Company's embedded net plant investment and related costs. The Average Remaining Life Technique gives consideration not only to the average service life and survival characteristics plus the net salvage component, but also recognizes the level of depreciation which has been accrued to date in developing the proposed depreciation rate. The Average Remaining Life Technique is used by regulated companies and regulatory agencies because it allows full recovery by the end of the property's useful life -- no more and no less.

VI. GROUP DEPRECIATION

Q17. Please explain the utilization of group depreciation.

A. Group depreciation is utilized to depreciate property when more than one item of property is being depreciated. Such an approach is appropriate because all of the items within a specific group typically do not have identical service lives, but have lives which are dispersed over a range of time. Utilizing group depreciation allows for a uniform application of depreciation rates to groups of similar property in lieu of performing extensive depreciation calculations on an item-by-item basis. The Broad Group approach is a recognized common group depreciation procedure.

The Broad Group Procedure recovers the investment within the asset group over the average service life of the property group. Given that there is dispersion within each property group, there are variations of retirement ages for the many investments within each property group. That is, some properties retire early (before average service life) while others retire at older ages (after average service life). This dispersion of retirement ages defines the survival pattern experienced by the applicable property group.

Q18. What factors influence the determination of the recommended annual depreciation rates included in your depreciation reports?

A. The depreciation rates reflect four principal factors: (1) the plant in service by vintage, (2) the book depreciation reserve, (3) the future net salvage, and (4) the composite remaining life for the property group. Factors considered in arriving at the service life are the average age, realized life and the survival characteristics of the property. The net salvage estimate is influenced by both past experience and future estimates of the cost of removal and gross salvage amounts.

Q19. Please explain further the assumptions considered when utilizing your depreciation approach.

A. According to my approach, the Company will recover its un-depreciated fixed capital investment through annual depreciation expense in each year throughout the useful life of the property. The Average Remaining Life Technique incorporates the future life expectancy of the property, the vintaged surviving plant in service, the survival characteristics, together with the book depreciation reserve balance and future net salvage in developing the amounts for each property account. Accordingly, Average Remaining Life depreciation meets the objective of providing a Straight Line recovery of the Company's fixed capital property investments.

Q20. Please explain further the group you have used.

A. My depreciation calculations, as applied in this study, follow a group depreciation approach. The group approach refers to the method of calculating annual depreciation based on the summation of the investment in any one plant group rather than calculation of depreciation for each individual unit of plant. In theory, each unit achieves average service life by the time of retirement. Accordingly, the full cost of the investment will be credited to plant in service when the retirement occurs, and likewise the depreciation reserve will be debited with an equal retirement cost. No gain or loss is recognized at the time of property retirement because of the assumption that the property was retired at average service life.

VII. NET SALVAGE

Q21. What are the net salvage factors included in the determination of depreciation rates?

A. Net salvage is the difference between gross salvage, or the proceeds received when an asset is disposed of, and the cost of removing the asset from service. Net salvage is said to be positive if gross salvage exceeds the cost of removal. If the cost of removal exceeds gross salvage, the result is negative salvage. Many retired assets generate little, if any, positive salvage. Instead, numerous Company asset groups generate negative net salvage at the end of their lives due to the cost of removal.

The cost of removal includes costs such as demolishing, dismantling, tearing down, disconnecting or otherwise retiring/removing plant, as well as any environmental clean-up costs associated with the property. Net salvage includes any proceeds received from any sale of plant.

Net salvage experience is studied for a period of years to determine the trends which have occurred in the past. These trends are considered, together with any changes that are anticipated in the future, to determine the future net salvage factor for remaining life depreciation purposes. The net salvage percentage is determined by comparing the total net positive or negative salvage to the book cost of the property investment retired.

The method used to estimate the retirement cost is a standard analysis approach which is used to identify a company's historical experience with regard to what the end of life cost will be relative to the cost of the plant when first placed into service. This information, along with knowledge about the average age of the historical retirements that have occurred to date, allows an estimation of the level of retirement cost that will be experienced by the Company at the end of each property group's useful life. The study methodology utilized has been extensively set forth in depreciation textbooks and has been the accepted practice by depreciation professionals for many decades. Furthermore, the cost of removal analysis is the current standard practice used for mass assets by essentially all depreciation professionals in estimating future net salvage for the purpose of identifying the applicable depreciation rate for a property group. There is a direct relationship between the installation of specific plant and its corresponding removal.

The installation is its beginning of life cost while the removal is its end of life cost. Also, it is important to note that Average Remaining Life depreciation rates incorporate future net salvage which is typically more representative of recent versus long-term historical average net salvage.

The Company's historical net salvage experience was analyzed to identify the historical net salvage factor for each applicable property group and is included in Section 7 of the study. This analysis routinely finds that historical retirements have occurred at average ages significantly shorter than the property group's average service life. The occurrence of historical retirements at an age which is significantly younger than the average service life of the property category demonstrates that the historical data does not appropriately recognize the true level of retirement cost at the end of the property group's useful life. An additional level of cost to retire will occur due to the passage of time until all the current plant is retired at end of its life. That is, the level of retirement costs will increase over time until the average service life is attained. The additional inflation in the estimate of retirement cost is related to those additional years' cost increases (primarily the result of higher labor costs over time) that will occur prior to the end of the property group's average life.

To provide further explanation of the issue, several general principles surrounding property retirements and related net salvage should be highlighted. As property continues to age, assets that typically generate positive salvage when retired will generate a lower percentage of positive salvage as compared to the original cost of the property. By comparison, if the class of assets is one that typically generates negative net salvage (cost of removal) with increasing age at retirement, the negative net salvage percentage as compared to original cost will typically be greater. This situation is routinely driven by the higher labor costs that occur with the passage of time.

A simple example will aid in understanding the above net salvage analysis and the required adjustment to the historical results. Assume the following scenario: A company has two cars, Car #1 and Car #2, each purchased for $20,000. Car #1 is retired after 2 years and Car #2, is retired after 10 years. Accordingly, the average life of the two cars is six (6) years. Car #1 generates 75% salvage or $15,000 when retired and Car #2 generates 5% salvage or $1,000 when retired.

	Unit Cost	**Ret. Age (Yrs.)**	**% Salv.**	**Salvage Amount**
Car #1	$20,000	2	75%	$15,000
Car #2	$20,000	10	5%	$ 1,000
Total	$40,000	6	40%	$16,000

Assume an analysis of the experienced net salvage at year three (3). Based upon the Car #1 retirement, which was retired at a young age (2 yrs.) as compared to the average six (6) year life of the property group, the analysis indicates that the property group would generate 75% salvage. This indication is incorrect, however, because it is the result of basing the estimate on incomplete data. That is, the estimate is based upon the salvage generated from a retirement that occurred at an age which is far less than the average service life of the property group. The actual total net salvage that occurred over the average life of the assets (which experienced a six (6) year average life for the property group) is 40%, as opposed to the initial incorrect estimate of 75%.

This is exactly the situation that occurs with the majority of the Company's historical net salvage data, except that most of the Company's property groups routinely experience negative net salvage (cost of removal) as opposed to positive salvage.

VIII. DEPRECIATION STUDY ANALYSIS

Q22. Please explain what factors affect the length of the average service life that the Company's property may achieve.

A. Several factors contribute to the length of the average service life which the property achieves. The three major factors are: (1) physical; (2) functional; and (3) contingent casualties.

The physical factor includes such things as deterioration, wear and tear and the action of the natural elements. The functional factor includes inadequacy, obsolescence and requirements of governmental authorities. Obsolescence occurs when it is no longer economically feasible to use the property to provide service to customers or when technological advances have provided a substitute with superior performance. The remaining factor, contingent casualties, includes retirements caused by accidental damage or construction activity of one type or another.

In performing the life analysis for any property being studied, both past experience and future expectations must be considered in order to fully evaluate the circumstances that may have a bearing on the remaining life of the property.

This ensures the selection of an average service life which best represents the expected life of each property investment.

Q23. What study procedures were utilized to determine service lives for the Company's property?

A. Several study procedures were used to determine the prospective service lives recommended for the Company's plant in service. These include the review and analysis of historical, as well as anticipated, retirements, current and future construction technology, historical experience and future expectations of salvage and the cost of removal.

Service lives are affected by many different factors, some of which can be determined from studying past experience, others of which must rely heavily on future expectations. When physical characteristics are the controlling factor in determining the service life of property, historical experience is a useful tool in selecting service lives. In cases where there are changes in technology, regulatory requirements, Company policy or the development of a less costly alternative, historical experience is of lesser or little value. However, even when considering physical factors, the future lives of various properties may vary from those experienced in the recent past.

While a number of methods are available to study historical data, as I mentioned previously, the two methods most commonly utilized to determine average service lives for a company's property are the Retirement Rate Method and the Simulated Plant Record Method. I used the retirement rate method of analysis to study the company’s operating property investments.

Q24. Please explain further the use of the retirement rate method.

A. With this method of analysis, the Company's actuarial service life data, which is sorted by age, is used to develop a survivor curve (observed life table). This survivor curve is the basis upon which smooth curves (standard Iowa Curves) are matched or fitted to then determine the average service life being experienced by the property account under study. Computer processing provides the capability to review various experience bands throughout the life of the account to observe trends and changes. For each experience band analysis, an "observed life table" is constructed using the exposure and retirement experience within the selected band of years. In some cases, the total life cycle of the property has not been achieved and the experienced life table, when plotted, results in a "stub curve." It is the "stub curve," or the total life curve, if the total life curve is achieved, which is matched or fitted to the standard Iowa Curves. The matching process is performed both by computer analysis, using a least squares technique, and by overlaying the observed life tables on the selected smooth curves for visual reference. The fitted smooth curve is a benchmark which provides a basis to determine the estimated average service life for the property group under study.

Q25. Do the depreciation study reports contain charts which compare the analysis of the Company's actual historical data to the service life parameters you are proposing as a basis for your recommended annual depreciation rates?

A. Yes. Graphical representations of the Company’s plant balances versus simulated plant balances based upon the estimated lives and Iowa Curves are contained in Section 5 of the report.

Q26. You have referred to the use of the Iowa or smoothed survivor curves. Can you generally describe these curves and their purpose?

A. The preparation of a depreciation study typically incorporates smoothed curves to represent the experienced or estimated survival characteristics of the property. The "smoothed" or standard survivor curves are the "Iowa" family of curves developed at Iowa State University and which are widely used and accepted throughout the utility industry. The shape of the curves within the Iowa family is dependent upon whether the maximum rate of retirement occurs before, during or after the average service life. If the maximum retirement rate occurs earlier in life, it is a left (L) mode curve; if it occurs at average life, it is a symmetrical (S) mode curve; if it occurs after average life, it is a right (R) mode curve. In addition, there is the origin (O) mode curve for plant which has heavy retirements at the beginning of life.

At any particular point in time, actual Company plant may not have completed its life cycle. Therefore, the survivor table generated from the Company data is not complete. This situation requires that an estimate be made with regard to the incomplete segment of the property group's life experience. Further, actual company experience often varies from age interval to age interval, making its utilization for average service estimation difficult. Accordingly, the Iowa Curves are used to both extend Company experience to zero percent surviving as well as to smooth actual Company data.

Q27. What is the principal reason for completing the detailed historical life and salvage analysis?

A. The detailed historical analysis is prepared as a tool from which to make informed assessments as to the appropriate service life and salvage parameters over which to recover the Company's plant investment. However, in addition to the available historic data, consideration must be given to current events, the Company's ongoing operations, Company management's future plans, and general industry events which are anticipated to impact the lives that will be achieved by plant in service.

IX. COMPREHENSIVE DEPRECIATION STUDY RESULTS AS OF December 31, 2015 and December 31, 2014

Q28. What is the basis for the Company's currently approved gas depreciation rates?

A. As shown in Exhibit No. ___(EMR-1), Table 1, pages 2-1 to 2-2, the prior depreciation rates for the plant were based upon depreciation parameters set forth in a study completed using the Company's plant investment data through December 31, 2008. The current account level depreciation rates composite to an annual depreciation rate of 3.27 percent when applied to each of the December 31, 2015 plant in service account balances.

Q29. What are the most notable changes in annual depreciation rates and expense between the present and proposed depreciation rates as set forth in Section 2 of the Montana-Dakota gas depreciation report?

A. With regard to gas plant in service, several of the proposed rates reflect changes (as outlined in Section 4 of the study) from the current depreciation rates.

The most notable depreciation changes occurred relative to Account 376.20 – Plastic Mains, Account 380.20 - Plastic Services, Account 381.00 - Meters, Account 392.2 - Transportation Equipment - Cars & Trucks, and Account 396.20 – Power Operated Equipment.

The proposed depreciation rate for Account 376.20 – Plastic Mains, increased from 2.15 percent to 3.41 percent. The proposed depreciation rate increased notwithstanding the fact that the underlying depreciation parameters remained the same. Based upon the Company's actual historical plant in service and net salvage data service life and net salvage parameters were estimated to develop the proposed depreciation rate. The proposed average service life remained the same as the current average service life of forty-seven (47) years. Likewise, the future negative net salvage remained the same at negative -50 percent. Accordingly, the ARL depreciation rate increase is being driven by the fact that the current book depreciation reserve is at a lower level than required relative to the estimated depreciation parameters and currently average age of the property group. Furthermore, as noted in Section 4 of the depreciation study, the Company is in the process of developing a plan and process to replace certain identified vintage plastic pipes as a part of its Distribution Integrity Management Program. These vintage pipes are currently in service across the Company's service territory.

The proposed depreciation rate for Account 380.20 – Plastic Services, increased from 6.46 percent to 7.06 percent. Based upon the Company's actual historical plant in service and net salvage data service life and net salvage parameters were estimated for the property group as outlined in section 4 of this depreciation study report. The proposed average service life is a thirty-eight (38) years, as compared to a forty (40) year average service life underlying the present depreciation rate. The future net salvage underlying the proposed depreciation rates is the same negative two hundred (200) percent as underlying the current depreciation rate. The proposed depreciation rate is the result of a minor change to the average service life and more significantly to the fact that the current book depreciation reserve is at a lower level than required relative to the estimated depreciation parameters and currently average age of the property group. Furthermore, as noted in Section 4 of the depreciation study, the Company is in the process of developing a plan and process to replace to replace certain identified vintage plastic pipes as a part of its Distribution Integrity Management Program. These vintage pipes are currently in service across the Company's service territory.

The depreciation rate relative to Account 381.00 - Meters increased from 3.01 percent to 4.13 percent. The current estimated average service life is thirty-five (35) years and the net salvage factor is estimated at negative -15 percent. The average service life underlying the proposed depreciation rate is thirty-one (31) years and the future net salvage is estimated at negative -20 percent. In prior years, the Company implemented an AMR system through the installation of ERTs on its gas meters with the result that a large portion of Meter reads are now automated. It has been approximately 8 years since the initial implementation, thus Meters are beginning to age notwithstanding the fact that Meters are cycled and tested on a routine basis, with new Meters purchased and installed as required.

Presently, management estimates that approximately 10 percent of the Company's Meters need to be replaced.

The depreciation rate relative to Account 392.2 - Transportation Equipment - Cars & Trucks increased from 0.26 percent to 7.25 percent. The current estimated average service life is 7 years and the underlying net salvage factor is 20 percent. The average service life underlying the proposed depreciation rate is nine (9) years and the estimated future net salvage is 20 percent. Notwithstanding that the average service life for the proposed depreciation rate was lengthened, the depreciation rate increase is the product of the fact that the property group life is short and the current depreciation rate is very low (the plant investment was nearly fully depreciated at the time of the development of the current depreciation rate) plus, during the time between depreciation studies, even a moderate variation in plant activity can cause the resulting depreciation to vary materially.

The depreciation rate relative to Account 396.20 – Power Operated Equipment Account increased from 0.23 percent to 5.30 percent. The current estimated average service life is 4 years and the net salvage factor is estimated at 80 percent. The average service life underlying the proposed depreciation rate is three (3) years and the estimated future net salvage is 85 percent. The depreciation rate increase is the product of the fact that the property group life is very short and the current depreciation rate is very low (the plant investment was nearly fully depreciated at the time of the development of the current depreciation rate) plus, during the time between depreciation studies, even a moderate variation in plant activity can cause the resulting depreciation to vary materially.

Q29. What is the net change to the composite depreciation rate under the proposed gas depreciation rates in comparison to December 31, 2015 present depreciation rates?

A. Application of the proposed account level depreciation rates to the Company's plant in service as of December 31, 2015 produces a composite depreciation rate of 4.23 percent. By comparison the application of the December 31, 2015 the currently utilized account level depreciation rates to the Company's plant in service as of December 31, 2015 produces a composite depreciation rate of 3.27 percent.

Q30. What is the net change in annual depreciation expense under the proposed depreciation rates in comparison to present December 31, 2015 depreciation rates?

A. Exhibit No.___(EMR-1), Section 2, Table 1, pages 2-1 to 2-2 indicates a net increase in annualized depreciation expense of $4,104,693 in comparison to the depreciation expense produced by the current depreciation rates, when applied to the Company's plant in service investment as of December 31, 2015.

Q33. Have you prepared an exhibit which compares the composite depreciation rates versus the account level deprecation rates from the December 31, 2008 depreciation study when applied to the Company's December 31, 2014 Common plant in service balances?

A. Yes, that information is contained on Exhibit No.___(EMR-2).

Q34. What is the net change to the Company's Common Plant composite depreciation rate under the proposed December 31, 2014 depreciation study

rates in comparison to present book depreciation rates when applied to the Common plant in service as of December 31, 2014?

A. Exhibit No. ___(EMR-2) shows the application of the proposed December 31, 2008 depreciation study account level depreciation rates to the Company's Common plant in service as of December 31, 2014, which, as shown on page 1 of Section 2, produces a composite depreciation rate of 3.89 percent. By comparison, the application of the proposed common depreciation rates (Column j) to the Company's plant in service as of December 31, 2014 produces a composite depreciation rate of 4.30 percent, or an increase in the composite rate for Montana-Dakota Common Plant of 0.41 based on 2014 plant in service levels.

Q35. What are the most notable changes in annual depreciation rates and expense between the present and proposed depreciation rates as set forth in Section 2 of the Montana-Dakota Common Plant depreciation report?

A. With regard to Common plant in service, one property account reflects a notable change (as outlined in Section 4 of the study) from the current depreciation rates.

The account with the most notable depreciation/amortization change occurred relative to Account 392.20 - Transportation Equipment - Cars & Trucks. The depreciation rate relative to Account 392.20 - Transportation Equipment - Cars & Trucks increased from 4.11 percent to 6.65 percent. Contributing to the depreciation expense increase is the change in the estimated average service life from seven to nine years while the future net salvage estimate remained at 20%. However, the more significant driver of the depreciation rate increase is the fact that the current book depreciation reserve is currently lower than required in comparison to the current age of the property group's investment.

X. RECOMMENDATION

Q36. What is your recommendation in this proceeding?

A. I recommend that the proposed depreciation rates set forth in the comprehensive depreciation study reports be uniformly and prospectively adopted by the Commission for regulatory purposes as well as by the Company for accounting purposes.

Q37. Does this conclude your direct testimony?

A. Yes, it does.

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

Experience includes approximately 40 years of service in the public utility field. Mr. Robinson has performed services in the areas of depreciation, original cost, valuation, cost of service, and bill analysis within numerous regulatory jurisdictions and property tax agencies throughout the Eastern, Midwestern, Southwestern, and Pacific regions of the United States, Canada plus various areas of the Caribbean.

EXPERIENCE

1977 to Date

AUS Consultants. Various positions - currently Principal. Mr. Robinson has prepared studies and coordinated analysis related to valuation, depreciation, original cost, trended original cost, cost of service, bill analysis, as well as analysis of expenses, revenues and income for various municipal and an extensive number of investor-owned electric, gas, water, wastewater, and telecommunications utilities.

Studies prepared have required the review of company records, inspection of property, the preparation of property inventories and original costs, preparation and review of mortality studies, selection of proper service lives, life characteristics and analysis of salvage, and analysis of capital recovery impact of changing depreciation methods.

During his many years of experience, Mr. Robinson has been involved in and/or responsible for an extensive quantity of comprehensive depreciation studies. Numerous early year's depreciation studies were prepared manually without the convenience of computer software systems. Subsequent, during the mid/late 1970's, Mr. Robinson became responsible for the completion of the many depreciation studies performed for the firm's clients. As part of that responsibility, Mr. Robinson was involved in not only performing the studies, but also in assisting AUS Consultants' MIS department in developing and testing various computer depreciation models. The studies performed by Mr. Robinson or under his direction have included all types of utilities, including electric, gas, water, wastewater, and telecommunications. During Mr. Robinson's career he has been involved in the preparation of more than a hundred depreciation related projects.

A Certified Depreciation Professional (CDP), Mr. Robinson, as a Principal of AUS Consultants provides services to the firm's clients with regard to depreciation and cost based valuation issues. With more than forty (40) years' experience, he began his career as a staff member of the Plant Accounting Department of United Telephone (now Sprint) Eastern Group Headquarters subsequent to which he has spent the past thirty-five (35) plus years, as a consultant, preparing depreciation and valuation studies for gas, pipeline, electric, telecommunications, water, and wastewater utilities. In conjunction with the provision of these services, Mr. Robinson has testified on many occasions before numerous regulatory agencies (including state, federal, and property tax agencies throughout the U.S., Canada, and the Caribbean in support of the many studies completed for his diverse list of clients. In addition he has negotiated depreciation rates with various state regulatory agencies, the FCC Staff, and the FERC Staff. Mr. Robinson has also participated in several FCC, State, Company three-way depreciation re-prescription meetings.

With regard to valuation matters Mr. Robinson has been involved with the development of cost indexes from the earliest part of his career through the present. During his earlier years, he assisted and/or developed and utilized cost indexes to prepare reproduction cost and related fair value determinations for various of the firm's regulated utility clients. Subsequently, he attained extensive experience in preparing custom indexes, replacement cost, and depreciated replacement cost studies, having been responsible for preparing many such cost studies relative to various clients within the telecommunications industry during

PROFESSIONAL QUALIFICATIONS
OF
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the past twenty (20) plus year period.

He is also responsible for developing and publishing the firm's AUS Telephone Plant Index (successor to the Handy Whitman and C A Turner Telephone Construction Cost Index), a reproduction cost index subscribed to by various operating companies, regulatory agencies, and consultants.

Mr. Robinson is a founding member and past President of the Society of Depreciation Professionals, a professional organization that provides depreciation training, as well as provides a forum for discussion of depreciation issues. He is also a member of the American Gas Association (AGA) Accounting Services Committee and past chairman of the Statistics, Bibliography, Court Regulatory Sub-Committee of the AGA Depreciation Committee. As a member of that organization, he co-authored a publication entitled **"**An Introduction to Net Salvage of Public Utility Plant**"**. Mr. Robinson has completed various previous presentations on the subject of depreciation studies as well as depreciated replacement cost to industry organizations and to property tax appraiser staffs.

1975 to 1977

Gannett, Fleming, Corddry & Carpenter, Inc. Valuation Analyst in the Valuation Division where his duties and responsibilities included the classifications, analysis and coordination of data in the development of depreciation rates for various companies including telephone, gas, water and electric utilities.

1971 to 1975

Weber, Fick & Wilson (Acquired by AUS Consultants), Public Utility Analyst engaged in the unitization and subsequent application of costs in the pricing of inventories for original cost determination, depreciation and salvage studies to determine proper annual depreciation rates and trended original cost studies used in the determination of utility rate base.

1966 to 1971

United Telephone Company of Pennsylvania (now Sprint/United Telephone Company of Pa.). As a staff member of the Plant Accounting Department, his duties and responsibilities included various plant accounting ledgers, unitization of location and mass property accounts, as well as special studies related to insurance and tax valuations of utility plant in service.

TESTIMONY

Jurisdictions testified in include Alberta, Arizona, California, Connecticut, Delaware, District of Columbia, FERC, Florida, Indiana, Illinois, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Montana, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, South Dakota, Oklahoma, Nevada, Pennsylvania, Rhode Island, South Carolina, Tennessee, Utah, and Virgin Islands. Extensive expert testimony has been presented on the subjects including Depreciation, Capital Recovery, Plant in Service Measures of Value, Depreciated Reproduction Cost, and Depreciated Replacement Cost. Numerous additional depreciation studies have been completed and filed in various different jurisdictions for which testimony appearances were not required.

PERSONAL

Education:

PROFESSIONAL QUALIFICATIONS
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Graduate of Harrisburg Area Community College with an Associate of Arts Degree in Accounting, and has undertaken further studies at University Center of Harrisburg. Successfully completed numerous programs related to service life and salvage estimation, forecasting, and evaluation sponsored by Depreciation Programs, Inc. at Calvin College Campus, Grand Rapids, Michigan. In addition, Mr. Robinson successfully completed cost of service seminars sponsored by the American Water Works Association. He received his CDP (Certified Depreciation Professional) designation by Exam during 1996.

List of Clients Served

CATV

Storer Broadcasting Company
  (DE, MD, MN)
Cable Television Consortium

ELECTRIC

Atlantic City Electric d/b/a Conectiv Power Delivery
Borough of Butler - Electric Dept.
Conectiv Power Delivery
Consolidated Edison Co of NY
Consolidated Hydro, Inc.
Delmarva Power and Light Company
  Delaware
  Maryland
Duquesne Light Company
Hershey Electric Company
Kentucky Utilities
Lockhart Power Company
Louisville Gas & Electric Co. - Elec. Div.
Montana – Dakota Utilities Co – Elec. Div
Nantahala Power and Light Company
New York State Electric and Gas Corp
Northern Indiana Public Service Co
Pennsylvania Power Company
Philadelphia Electric Company
Potomac Electric Power Company
  Maryland
  Washington DC
Progress Energy - Carolinas
Progress Energy - Florida, Inc.
Public Service Company of New Mexico
Public Service Electric & Gas Company
Rochester Gas and Electric Corporation
The United Illuminating Company
Wellsboro Electric Company
Vermont Electric Power, Inc.

GAS

ATCO Gas
ATCO Pipelines
Atlanta Gas Light Company
Bay State Gas Company
C & T Enterprises, Inc.
  Valley Cities Waverly Gas Company
Canadian Western Natural
  Gas Company Limited
Cascade Natural Gas Corporation
Citizens Gas & Coke Utility
Columbia Gas of Pennsylvania, Inc.
Connecticut Natural Gas Corporation
Consolidated Edison Co of New York
East Ohio Gas
North Carolina Gas Service
North Penn Gas
Northern Indiana Public Service Co.
Northern Utilities, Inc.-Maine
Northern Utilities, Inc.-New Hampshire
Oklahoma Natural Gas Company
Pacific Gas & Electric Company
Paiute Pipeline
Pennsylvania Gas & Water Company
PG Energy Inc.
Pennsylvania and Southern Gas Company
  Valley Cities Division
  Waverly Division
Pipeline Industry Group

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

Elkton Gas Service
Granite State Gas Transmission, Inc.
Great Plains Natural Gas Co.
Kansas Gas Service
Louisville Gas & Electric Co. - Gas Division
Montana Dakota Utilities - Gas Division
National Fuel Gas Distr. Corp., NY
National Fuel Gas Supply
New York State Electric & Gas Corp
NICOR Gas Company
Northeast Heat & Light Company
Providence Gas Company
Public Service Electric & Gas Co
Public Service Company of New Mexico
Roanoke Gas Company
Rochester Gas and Electric Corporation
Saxonburg Heat & Light Company
Sierra Pacific Power Co/NV Energy
Southern Connecticut Gas Company
Southwest Gas Corporation
T.W. Phillips Gas & Oil Company
Williams Companies

GENERAL CLIENTS

Arthur Andersen
Pricewaterhouse Coopers
Electric Utility Consultants, Inc.
Ernst & Young
Standard & Poors

REGULATORY AND GOVERNMENTAL

Regulatory Commission of Alaska
  Alaska Electric Light & Power Company
  Interior Telephone Company, Inc
  Fairbanks Water & Wastewater
  Mukluk Telephone Company, Inc
  TDX North Slope Generating
  United KUC, Inc
  United Utilities, Inc.
Arizona Corporation Commission
  Mountain States Telephone & Telegraph
  Southwest Gas Corporation
Baltimore County, MD
Bensalem Township - Water
Bethlehem Authority - Water
Borough of Butler, NJ
Borough of Media Water Works
City of New Orleans, LA
Delaware Public Service Commission
Delaware River Port Authority
Diamond State Telephone Company
Kansas Corporation Commission
  Southwest Bell
Public Service Comm. of Nevada
  Nevada Bell
Town of Waterford, CT
  Northeast Utilities
Washington, D.C. - PSC
  C&P Telephone Company
  Potomac Electric Power Company

TELECOMMUNICATIONS

Ace Telephone Association - IA & MN
Air Touch Communications
ALLTEL Pennsylvania, Inc.
AT&T-Advance Solutions, Inc-CA
BellSouth Telecommunications
Buffalo Valley Telephone Company
Paging Industry Study Group
  AirTouch Paging
  Mobile Comm
Paging Network, Inc.
  Skytel
  USA Mobile Communications

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Cellular Industry Study Group
  AT&T Wireless
BellSouth Communications
  GTE Mobilnet
Brighthouse Networks-Citrus County
Cable & Wireless
Chenango & Unadilla Telephone Company
Cingular Wireless
  Cingular Wireless – California
  Cingular Wireless – Houston
  Cingular Wireless - Massachusetts
Commonwealth Telephone Company
CTC of Michigan
CTC of Virginia
Denver & Ephrata Telephone & Telegraph Co.
  D & E Network
  D & E System
Embarq Florida, Inc.
Empire Telephone Corporation
Illinois Consolidated Telephone Co.
Jamestown Telephone Corporation
Leesport Telephone Company
Lewisberry Telephone Company
Los Angeles Cellular Telephone Co.
MCI International, Inc.
MCI Telecommunications Corp.
MFS Communication Company, Inc.
Marianna & Scenery Hill Tel. Co.
Mid State Telephone Company
Motorola, Inc.
Nevada Bell
New Jersey Telephone Company
The North-Eastern Pennsylvania Tel. Co.
Pacific Bell
Pactel Cellular
Quaker State Telephone Company
Qwest Communications Corporation
  Qwest – Arizona
  Qwest – Iowa
  Qwest -- Montana
  Qwest -- Washington
RCA Global Communications, Inc.
SBC Ameritech Corporation
  SBC -- Arkansas
  SBC -- Kansas
  SBC -- Michigan
  SBC -- Missouri
  SBC -- Ohio
  SBC -- Oklahoma
  SBC – Wisconsin
  SBC – West – California
  SBC – West – Nevada
Southwestern Bell Telephone Company
Standard Telephone Company
Telecommunications d'Haiti
Telephone Utilities of Pennsylvania
United Telephone Company of New Jersey
Verizon Wireless
  Verizon – California
  Verizon – Kentucky
  Verizon – Massachusetts
  Verizon -- Montana
  Verizon – South Carolina
  Verizon -- Utah
  Verizon -- Washington
  Verizon – Wyoming
  Verizon – Total Company
Virgin Islands Telephone Corporation
Williams Communication
WilTel, Inc.

WATER

Arizona Water Company
Artesian Water Company
City of Auburn
Bethlehem Authority – Water
California Water Service Company
California-American Water Company
  Citizens Water – California
  Citizens Water – Arizona
Clinton Water Company
Columbia Water Company
Commonwealth Water Company
Consumers New Jersey Water Company
Dauphin Consolidated Water Supply Co.
Dominguez Water Company
Elizabethville Water Company
City of Fairfax
Garden State Water Company
Hackensack Water Company
Monarch Utilities, Inc.
Monmouth Consolidated Water Company
New Haven Water Company
New Jersey Water Company
New Mexico-American Water Company, Inc.
Newtown Artesian Water Company
New York-American Water Company
Ohio-American Water Company
Palm Coast Utility Corporation
Pennichuck East Utility
Pennichuck Water Works
Pennsylvania-American Water Company
Pennsylvania Gas & Water Company
Pennsylvania Water Company
  Erie & Sayre Divisions
Philadelphia Suburban Water Company
Pinelands Water Company
Public Service Water Company

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Hawaii Water Service
  Ka'anapali Water
  Kona Water
  Waikoloa Village Water
  Waikoloa Resort Water
  Waikoloa Resort Irrigation
Hershey Water Company
Illinois-American Water Company
Indian Rock Water Company
Indianapolis Water Company
Iowa-American Water Company
Keystone Water Company
Manufacturers Water Company
Masury Water Company
Middlesex Water Company
Monarch Utilities, Inc.
Riverton Consolidated Water Company
Roaring Creek Water Company
Rock Springs Water Company
Shenango Valley Water Company
Southern California Water Company
Spring Valley Water Company
Spring Valley Water Company
Tidewater Utilities, Inc.
United Water - Delaware
United Water - Toms River
United Water - New Jersey
United Water - Pennsylvania
United Water - Virginia
Virginia American Water Company
Western Pennsylvania Water Company
York Water Company

STEAM

Consolidated Edison Co of New York

WASTEWATER

California - American Water Company
 Citizens Sewer – Arizona
Hawaii Water Service Company-Wastewater
  Kona Wastewater
  Pukalani Wastewater Company
  Wailoloa Resort Wastewater
Illinois-American Company – Wastewater
Monarch Utilities, Inc.
New Jersey Water Company
  Sewer Districts
Palm Coast Utility Corporation
Pinelands Sewer Company
Wynnewood Sewer Company

PROFESSIONAL QUALIFICATIONS

CDP (Certified Depreciation Professional) by Exam during October, 1996

PROFESSIONAL AFFILIATIONS

American Water Works Association
American Gas Association
American Railway Engineering Association
Pennsylvania Gas Association
Pennsylvania Municipal Authorities Association
Member AGA Accounting Services Committee
Society of Depreciation Professionals-Founding Member, Chairman Coordinating and Membership Committees, Treasurer, President, and Past President

PUBLICATIONS

AGA/EEI Depreciation Accounting Committee, Contributing Author 1989, "An Introduction to Net Salvage of Public Utility Plant"

"Replacement Cost and Service Life Studies", *Journal of Property Tax Management*, Fall 1994, Volume 6, Issue 2

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS

SPEECHES AND PRESENTATIONS

"Depreciated Replacement Cost", Institute of Property Taxation - 18th Annual Conference, San Francisco, CA

"RCNLD Issues for Utilities", The National Association of Railroad & Public Utilities Tax Representative, 1997 Annual Conference, North Lake Tahoe, NV

"Useful Service Lives of Cellular Industry Assets", State of Florida, Department of Revenue, Industry/Government Task Force (April 1997)

"Appraisal and Valuation Issues Associated with Technology Changes within the Wireless Industry", 30th Annual Wichita Program - Appraisal for Ad Valorem Taxation of Communications, Energy, and Transportation Program, Wichita State University - July 30-August 3, 2000

"Physical/Functional Obsolescence, Residual Values/Floors (Net Salvage)", 32th Annual Wichita Program - Appraisal for Ad Valorem Taxation of Communications, Energy, and Transportation Program Wichita State University - July 28-August 1, 2002

"Depreciation Study Preparation", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, Lake Tahoe, Nevada - October 28, 2002

"Use of Replacement Cost to Value High Tech Equipment" Southeastern Association of Tax Administrators, 53rd. Annual Conference, Savannah, Georgia - July 14-July 16, 2003

"Property Tax: Use of Replacement Cost in the Appraisal of Telecommunications Companies", Western States Association of Tax Representatives (WSATR), WSATA 2003 Annual Meeting, Austin, TX - Sept. 9, 2003

"Replacement Cost & Depreciated Replacement Cost Presentation", Southwestern Bell Telephone Company – Arkansas PSC – Tax Division - August, 2003

"Valuation of Assets", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, Scottsdale, Arizona - December 9, 2003

"*Property Tax: Use of Replacement Cost in the Appraisal of Telecommunications Companies",* Oklahoma State Board of Equalization Public Service Valuation Guidelines Subcommittee – Oklahoma City, OK – Feb 5, 2004

"*Net Salvage Issues In Rate Cases",* AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, San Antonio, Texas - May 17, 2004

"*Current Depreciation Issues: Point-Counterpoint",* AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, Savannah, Georgia – November 14, 2006

"Depreciation & Cost of Removal", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, Tucson, Arizona – October 24, 2007

"Whole Life versus Remaining Life", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, San Francisco, California – May 21, 2008

"Obsolescence-Measuring the Impact for Industries Experiencing Change""Depreciation & Cost of Removal", IPT 32nd Annual

PROFESSIONAL QUALIFICATIONS
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Conference, Atlanta, Georgia, June 23, 2008

"An Alternative to IFRS Unit Depreciation", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, Baltimore, Maryland – May 18, 2009

"Alternative to IFRS Unit Depreciation", Society of Depreciation Professionals, Albuquerque, New Mexico, – October 5, 2009

"Depreciation Training", Regulatory Commission of Alaska (RCA), Anchorage, Alaska, October 26 & 28, 2010

"Physical Depreciation – The Uses and Abuses of Iowa Curves and Other Errors", IPT Property Tax Symposium, Austin, Texas, November 2, 2010

"Preparing To Be A Depreciation Witness", AGA Accounting Services Committee/EEI Property Accounting & Valuation Committee, New Orleans, Louisiana – May 19, 2011

"Depreciation – The Last 25 Years & More", Society of Depreciation Professionals, Atlanta, Georgia, – September 20, 2011

"A Roadmap to Replacement Cost", 42nd Annual Wichita Program - Appraisal for Ad Valorem Taxation of Communications, Energy, and Transportation Program, Wichita State University - July 29-August 2, 2012

DEPRECIATION TRAINING INSTRUCTOR-CLASSES

Regulatory Commission of Alaska, Anchorage, AK, Oct 2012

EUCI Depreciation Training, Houston, TX, Nov 8-9, 2012

EUCI Depreciation Training, Denver, CO, May 6-7, 2013

EUCI Depreciation Training, Chicago, IL, Nov 14-15, 2013

EUCI Depreciation Training, Pasadena, CA, Apr 22-23, 2014

EUCI Depreciation Training, Newport Beach, CA, Dec 16-17, 2014

EUCI Depreciation Training, Denver, CO, Jun 24-25, 2015

EUCI Depreciation Training, Anaheim, CA, Apr 25-26, 2016

EUCI Fortis Depreciation Training, Calgary, AB, May 10-11, 2016

EUCI Depreciation Training, Denver, CO, Oct 27-28, 2016

EUCI Depreciation Training, Denver, CO, Feb 7-8, 2017

PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
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SUMMARY OF TESTIMONY APPEARANCES – HEARINGS & DEPOSITIONS (PLUS DECLARATIONS)

Jurisdiction	Client	Docket/Application	Subject
Alberta	Canadian Western Natural Gas Company Limited	980413	Depreciation
	ATCO Pipelines	1292783	Depreciation
		Appl. 1527976, Proc ID 13	Depreciation
Arizona	Arizona Corp. Comm./ Mtn. Bell	9981-E-1051	RCN/RCND *
	Arizona Corp. Comm./ Southwest Gas Corp.	U-1551-80-70	RCN/RCND *
	Qwest Corporation-Arizona	TX2001-000662	Property Tax Valuation Deposition
California (PUC & State Board of Equalization)	MCI Telecommunications Corporation	274	Replacement Cost/ Depr. Repl. Cost
		SAU87-38	Replacement Cost/ Depr. Repl. Cost
		SAU91-101	Replacement Cost/ Depr. Repl. Cost
	SBC-California	SAU 279 Declaration	Property Tax Valuation
	SBC-California	January 31, 2005 Declaration	Property Tax Valuation
	Southern California Water Company	ABJ-4	Depreciation
Connecticut	Connecticut Natural Gas Corp	08-12-06	Depreciation
		13-06-08	Depreciation
	Southern Connecticut Gas Co.	89-09-06	P.I.S. Measures of Value and Depreciation
		08-12-07	Depreciation
	The United Illuminating Company	16-06-04	Depreciation
Delaware	Artesian Water Company	82-20	Depreciation
		87-3	Depreciation
	United Water - Delaware	96-164	Depreciation
		98-98	Depreciation
	Delaware Public Service Comm./ Diamond State Telephone Co.	81-8	P.I.S. Measures of Value and Depreciation

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Jurisdiction	Client	Docket/Application	Subject
	Delmarva Power & Light Company	05-304	Depreciation
	Tidewater Utilities, Inc/ Public Water and Supply, Inc	99-466	Depreciation
District of Columbia	Potomac Electric Power Co.	F.C. 869	Depreciation
	Washington, DC PSC/C&P Tel Corp.	F.C. 777	Depreciation
	Washington, DC PSC/ Potomac Electric Power Co.	F.C. 785 F.C. 813	Capital Recovery/ Depreciation
FERC	Granite State Gas Transmission, Inc.	RP91-164-000	Depreciation
	Paiute Pipeline	RP96-306-000	Depreciation
	Public Service Company of NM	ER-11-1915-000	Depreciation
Florida (County of Duval)	BellSouth Telecommunications	Petitions 1795-1800	Replacement Cost/ Depr. Repl. Cos
(County of Lee)	Sprint-Florida, Inc (Embarq)	Case No. 02-CA-013330-1	Replacement Cost
(County of St. Lucie)	BellSouth Telecommunications	1999 Petitions	Replacement Cost/ Depr. Repl. Cost
(County of Citrus)	Embarq	Case No. 2003-CA4473, 2004-CA4565, 2005-CA5010	Property Tax Valuation Deposition
(County of Lee)	Embarq	Case No. 02-13330 CA-WCM	Property Tax Valuation Deposition
	Progress Energy – Florida Progress Energy – Florida	050078-EI 090079-EI	Depreciation Depreciation
Illinois	Illinois - American Water Company	00-0340 02-0690 07-0507	Depreciation Depreciation Depreciation
	Illinois Consolidated Telephone Co.	81-0264 82-0623	RCN/RCND * RCN/RCND *
Indiana	Northern Indiana Public Service Company	Cause No. 41746	Depreciation
Iowa (Dept of Rev)	Qwest Corporation-Iowa	883	Property Tax Valuation Deposition

**PROFESSIONAL QUALIFICATIONS
OF
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AUS CONSULTANTS**

Jurisdiction	Client	Docket/Application	Subject
Kansas	Kansas Gas Service	03-KGSG-602-RTS	Depreciation
Kentucky	Kentucky Utilities	Case No. 2003-00434	Depreciation
	Louisville Gas & Electric Electric Gas	Case No. 2003-00433	Depreciation
Maryland	Columbia Gas of Maryland, Inc.	9316	Depreciation
	Delmarva Power & Light Company	9093	Depreciation
	Potomac Electric Power Company	9092	Depreciation
Massachusetts	Bay State Gas Company	92-111 DTE 05-27	Depreciation Depreciation
Montana	Montana-Dakota Utilities Co-Gas	Docket #2012.9.100	Depreciation
	Montana-Dakota Utilities Co-Elec	Docket # 2007.7.79 Docket # 2010.8.82 Docket # 2015.6.51	Depreciation Depreciation Depreciation
	Qwest Corporation-Montana	06DORFC001 06DOTFC017	Property Tax Valuation Deposition
Nevada	Southwest Gas Corporation	04-3011	Depreciation
New Jersey	Atlantic City Electric d/b/a Conectiv Power Delivery	ER03020110	Depreciation
	Borough of Butler/ Butler Elec. Dept.	792-84	Valuation of Plant in Service Customer Revenue and Purchase Power
	Commonwealth Water Co.	842-100	Depreciation
	Consumers NJ Water Company	WR00030174	Depreciation
	Garden State Water Co.	WR91091483	Depreciation
	Middlesex Water Company	WR8602-240 WR90080884J	Depreciation Depreciation

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		WR96110818	Depreciation
Jurisdiction	**Client**	**Docket/Application**	**Subject**
	Monmouth Cons. Water Co.	8312-1113	Depreciation
	New Jersey Water Company	834-292	Depreciation
	Public Service Electric & Gas	GR05100845	Depreciation
	United Water Resources (formerly Hackensack Water Co.)	8506-663 WR90080792J WR95070303	Depreciation Depreciation Depreciation
	Toms River Water Company	WR95050219	Depreciation
New Hampshire	Northern Utilities, Inc.	DR91-081	Depreciation
New Mexico	New-Mexico American Water Company, Inc.	2813 03-00206-UT	Depreciation Depreciation
	Public Service Company of NM	08-00273-UT 10-00086-UT	Depreciation Depreciation
New York	New York-American Water Co.	28911	Depreciation
	New York State Elec. & Gas Corp. Electric Business & Common Plant	05-E-1222	Depreciation
	New York State Elec. & Gas Corp-Elec.	09-E-0715	Depreciation
	New York State Elec. & Gas Corp-Gas	09-G-0716	Depreciation
	Rochester Gas and Elec. Corp-Elec.	09-E-0717	Depreciation
	Rochester Gas and Elec. Corp-Gas	09-G-0718	Depreciation
	Spring Valley Water Co., Inc.	89-W-1151 92-W-0645	Depreciation Depreciation
North Carolina	Nantahala Power and Light Co.	E-13, SUB157	Depreciation
North Dakota	Montana-Dakota Utilities Co-Gas	Case No. PU-399-02-183	Depreciation
Oklahoma (State Board of Equalization)	SWBT-Oklahoma	EQ-2004-10	Property Tax Valuation Deposition
Pennsylvania	Borough of Media Water Works	R-912150	Depreciation
	Columbia Gas of Penna.	R-80031129	Depreciation and Valuation
	Commonwealth Telephone Co.	I-00920020	Depreciation

**PROFESSIONAL QUALIFICATIONS
OF
EARL M. ROBINSON, CDP
AUS CONSULTANTS**

Jurisdiction	Client	Docket/Application	Subject
	Keystone Water Company	R-842755	Capital Recovery/Depreciation
		R-842756	Capital Recovery/Depreciation
		R-842759	Capital Recovery/Depreciation
	Mid Penn Tel. Corp.	R-80071264	Depreciation
	Penna.-American Water Co.	R-891208	Depreciation
	Penna. Gas & Water Co. -	R-821961	Depreciation
	Gas Division	R-832475	Depreciation
	Penna. Gas & Water Co. -	R-822102	Depreciation
	Water Division	R-850178	Capital Recovery/Depreciation
		R-870853	Capital Recovery/Depreciation
	Penna. Gas & Water Co. - Scranton Division	R-901726	PIS Meas. of Value/Depreciation
		R-922482	Depreciation
	Penna. Gas & Water Co. - Spring Brook Division Nesbitt Service Area	R-911966	PIS Meas. of Value/Depreciation
	Crystal Lake Service Area	R-922404	PIS Meas. of Value/Depreciation
	Cease town/Watres Service Area	R-93266	Depreciation
	Penna. Power Company	R-811510	PIS Meas. of Value/Depreciation
		R-821918	PIS Meas. of Value/Depreciation
		R-832409	PIS Meas. of Value/Depreciation
		R-842740	PIS Meas. of Value/Depreciation
		R-850267	PIS Meas. of Value/Depreciation
		R-870732	PIS Meas. of Value/Depreciation
	Pennsylvania & Southern Gas Company	R-870686	Depreciation
	PG Energy Inc.	R-963612	PIS Meas. Of Value/Depr
		R-984280	PIS Meas. Of Value/Depr
		R-00061365	PIS Meas. OFValue/Depr
	Philadelphia Suburban	R-911892	Depreciation
	Water Company	R-922476	PIS Meas. of Value/Depreciation
		R-932868	PIS Meas. of

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OF
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AUS CONSULTANTS

Value/Depreciation

Jurisdiction	Client	Docket/Application	Subject
	Riverton Consolidated Water Co.	R-842675	Capital Recovery/Depreciation
	United Water - Pennsylvania	R-00973947	Depreciation
	Western Pennsylvania Water Company	R-842621	Capital Recovery/Depreciation
		R-842622	Capital Recovery/Depreciation
		R-842623	Capital Recovery/Depreciation
		R-842624	Capital Recovery/Depreciation
		R-842625	Capital Recovery/Depreciation
	Wellsboro Electric Company	R-00016356	Depreciation
Rhode Island	Providence Gas Company	1914	Depreciation
		2286	Depreciation
South Carolina	Lockhart Power Company	87-435-E	Depreciation
Tennessee (Board of Equalization)	Bellsouth – Tennessee	67-5-903	Property Tax Valuation Deposition
Utah	Verizon Wireless	05-0826, 05-0829	Property Tax Valuation Deposition & Hearing
Virgin Islands	Virgin Islands Tel. Corp.	264	Depreciation
		314	Depreciation
		316	Depreciation

* Reproduction Cost New/Reproduction Cost New Depreciated.

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

Before the North Dakota Public Service Commission

Case No. PU-17-_____

Direct Testimony
of
Matthew T. Shoemake

Q. Would you please state your name and business address?

A. Yes. My name is Matthew T. Shoemake, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am a Regulatory Analyst in the Regulatory Affairs Department for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resource Group, Inc.

Q. Would you please describe your duties as a Regulatory Analyst?

A. I prepare monthly purchase gas adjustment filings, weather normalization of volumes, assist in monthly fuel cost adjustment filings, and other filings required by state commissions.

Q. Would you please describe your education and professional background?

A. I graduated from Texas A&M University in College Station, Texas with a Bachelor of Science degree in Economics with a minor in Business

Administration. Prior to starting in my current role May of 2016, I was a quality control analyst for Knife River, a subsidiary of MDU Resources, for approximately 8 years.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the calculation of customer counts and normalized and projected volumes for each rate class underlying the projected revenues.

Q. What statements, schedules and exhibits are you sponsoring?

A. I am sponsoring the billing units presented on Statement K, pages 4 through 5.

Q. Would you describe the methodology used to calculate customer counts?

A. The Company's Customer Care and Billing System (CC&B) was the starting point for the development of the customer counts. A Microsoft Excel file containing the service address identification numbers (SA IDs) for each rate class was extracted from CC&B. The method to determine customer counts is a feature in Excel named Distinct Count, which counts the number of unique values. The Count feature in Excel counts the total number of values corresponding to a range of data. The Distinct Count was used to determine the number of customers billed each month as this was a method which accounted for adjustments and corrections to customer bills in the data set.

Q. Would you describe the development of the normalized volumes?

A. Volumes for residential, firm general, propane, Minot Air Force Base, and select interruptible and transportation customers were adjusted to reflect normal weather patterns. Each of the aforementioned customer classes were adjusted separately. Billing period sales volumes and customers, by month, were the starting point for the data utilized in the models. To incorporate seasonal weather patterns, billing period degree days were based on a 60 degree day. A 36 month OLS (ordinary least squares) regression analysis was then performed for each class of service. Using the results of the regression analysis for residential and firm general service, the daily baseload use per customer (the intercept of the OLS) was multiplied by the respective number of days in each calendar month to arrive at the monthly baseload use per customer. The use per degree day per customer (the slope of the OLS) was then applied to the normal billing period degree days (based on normal weather for 30 years) to determine the normalized heating use per customer. The results of each of these equations was then combined by the number of customers in each respective month to determine the normalized usage for the twelve months ended December 31, 2016.

Q. Would you describe how interruptible and transportation class customers and volumes were generated?

A. Interruptible customer counts (sales and transportation) were determined by using the Distinct Count feature in Excel. Volumes for Rate 71 (small interruptible sales), interruptible transportation Rates 81 (small), and 82 (large) were determined by first separating customers into heat sensitive and non-heat sensitive groups, based on usage patterns. For heat sensitive customers, a 36 month OLS regression was utilized at a district level with each district's respective degree days. For non-heat sensitive customers, a 3 year average was calculated for each customer except in a select few instances where 2 year averages were calculated (due to customers being in service for less than 3 years). Due to the low number of large interruptible transportation customers (Rate 82), an OLS regression was modeled for each customer rather than at a district level.

The Projected 2017 and 2018 customers and volumes for the interruptible service schedules were held at the normalized 2016 levels.

Q. Were customers added or removed and, if so, for what reasons?

A. Yes, specifically in Rates 70, 71, 81, and 85. During the time period of 2014 through 2016 there were a number of customers that changed rates under which they took service. To ensure that each customer's data was represented consistently throughout the data set, each customer account that changed rate classes was moved to the appropriate set. The majority of these customers were previously under Rate 71 and moved to their respective firm rates that represent the current rate at which they are billed.

Additional removal of customers from Rate 71 was also required. Due to the margin sharing adjustment for grain dryers through the PGA as authorized in Case No. PU-13-803 and maintained in PU-15-90, all grain drying customers were removed from normalized and projected volumes. To further ensure the integrity of the projected volumes, customers that were not active at the end of 2016 were completely removed from the entirety of the underlying data for rate 71.

Q. How were growth rates for customers for the projected years calculated?

A. A 2 year average growth rate for the Residential, Small Firm General and Large Firm General was determined to be representative of the growth expected for the future. In addition, the growth rate for the

Small Firm General class was applied to both the Small and Large Firm General classes as the growth rate for the Large Firm General class was not representative of the future. For the remaining classes, no growth was used so customer counts were left at their respective levels at the end of 2016. For the three rates that accounted for customer growth, the growth in the distinct count of customers for December 2015 through 2016 was averaged for each rate class. These average growth rates were applied to the year end 2016 customer counts for each rate to project 2017 and for 2017 to project 2018. The percentage of each rate's respective monthly customer counts for 2016 were applied to each of the total projections for 2017 and 2018 to obtain monthly customer projections that were used to determine projected volumes based on the OLS models.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

A Division of MDU Resources Group, Inc.

Before the North Dakota Public Service Commission

Case No. PU-17-___

Direct Testimony
of
Travis R. Jacobson

Q. **Would you please state your name and business address?**

A. Yes. My name is Travis R. Jacobson, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. **What is your position with Montana-Dakota Utilities Co.?**

A. I am the Regulatory Analysis Manager for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. **Would you please describe your duties as Regulatory Analysis Manager?**

A. I am responsible for the preparation of cost of service studies, fuel cost adjustments, purchased gas cost adjustments, and gas tracking adjustments in each of the jurisdictions in which Montana-Dakota operates.

Q. **Would you please describe your education and professional background?**

A. I graduated from Minot State University with a Bachelor of Science degree in Accounting, and I am a Certified Public Accountant (CPA). I started my career with Montana-Dakota in 1999 as a Financial Analyst in the Financial Reporting and Planning department. During my tenure with the Company I have held positions of increasing responsibility; including, Supervisor of Financial Reporting and Planning, and Manager of Financial Reporting and Planning before attaining my current position.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission, the Public Service Commissions of Montana and Wyoming, and the Public Utilities Commissions of Minnesota and South Dakota.

Q. Are you familiar with the books and records of Montana-Dakota and the manner in which they are kept?

A. Yes. Montana-Dakota's books and records are kept in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (US of A).

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the North Dakota gas operations per books cost of service for the twelve months ended

December 31, 2016 and the projected cost of service for 2017 and 2018. Based on the results, I have prepared the calculation of the revenue deficiency and the calculation of the interim request. I will discuss proposed changes to Rate 88 – Cost of Gas, proposed changes to Rate 99 – Cost of Gas Propane, present the base revenue requirement, and a projected 2019 revenue requirement in support of the proposed System Safety and Integrity Program Adjustment Mechanism Rate 94.

Q. What statements, schedules, and exhibits are you sponsoring?

A. I am sponsoring Statements A through C, Statements E through L (excluding Statement K, pages 4 and 5), Exhibit No.___(TRJ-1), the interim revenue requirement presented in Exhibit No.___(TRJ-2), and the proposed Rate 88 – Cost of Gas and proposed Rate 99 – Cost of Gas Propane presented in Appendix B of the Application. The revenue requirement supporting the proposed System Safety and Integrity Program Adjustment Mechanism Rate 94 is attached as Exhibit No.____(TRJ-3).

Q. Were these statements and exhibits prepared by you or under your direct supervision?

A. Yes, they were.

Revenue Requirement

Q. What were the results of North Dakota gas operations for 2016?

A. Statement J, pages 1 and 2 show the per books income statement and rate base for the total Company and North Dakota gas operations for 2016. As shown on page 1, North Dakota gas operations produced a return on rate base of 6.341 percent for the twelve months ended December 31, 2016. The details for each line item, i.e. sales revenue, other revenue, etc., are included in the referenced Statements.

Q. How was the per books cost of service allocated to North Dakota?

A. The Company utilizes a jurisdictional accounting system that directly assigns and/or allocates every item of revenue, expense, and rate base to the jurisdictions as part of the regular accounting process on a monthly basis. The allocation methods and procedures are the same as those that have previously been used in Commission proceedings and are based on the principle of assigning and/or allocating costs to the cost causer.

Q. What test period are you using to determine the revenue requirement?

A. The revenue requirement is based on a projected average 2018 test period. As stated by Ms. Kivisto, the primary reason for the increase in rates is the increased investment in distribution facilities to be completed by the end of 2018 to improve system safety and reliability and the depreciation and taxes associated with the increase in investment.

Montana-Dakota is using a future test year in accordance with North Dakota Century Code §49-05-04.1.

Q. Would you describe the development of the projected cost of service for 2017 and 2018?

A. The projected 2017 and 2018 cost of service is presented in Statement K, which contains all schedules supporting the income statement as summarized on page 1, and Statement L, which contains all of the schedules supporting the rate base as summarized on page 1. The revenues and expenses reflect the annual level that will be experienced when the new rates become effective. Likewise, the rate base reflects average 2017 and 2018 plant and related balances.

Income Statement

Q. Would you describe the development of the projected revenues and expenses contained in Statement K?

A. The projected revenues for 2017 and 2018 are summarized on Statement K, page 2. Mr. Shoemake discusses the development of the projected volumes in his testimony, and Ms. Bosch discusses the development of the sales and transportation revenues in her testimony.

Other operating revenues are projected to decrease from the 2016 level as shown on Statement K, page 6. Rent from Property was reduced to exclude rent from Company owned housing which was sold during 2015 through 2017 and to reflect actual property rental revenue for all other property.

Other Revenue was adjusted to update the revenue requirement for the Heskett III Pipeline and assign a portion of the revenue to gas operations upon completion of the town border station and pipeline serving Mandan, ND. Late payment and penalty revenues were also adjusted. Late payment revenues were projected for 2017 and 2018 based on the 2016 ratio of late payment revenue to billed sales and transportation revenue of 0.16 percent applied to projected 2017 and 2018 sales and transportation revenue. The 2017 and 2018 penalty revenues were restated to a three-year average for 2014 to 2016 to smooth out any year to year fluctuations. The 2016 per books Penalty Revenue line included collections related to gas extension agreements, which a Letter of Credit was received rather than a contribution. The Company adjusted the projected sales volumes and/or customer advances to match the

Company's investment for the affected customers; therefore, the 2016 revenue associated with gas extension agreements with a minimum bill provision were excluded for projected 2017 and 2018.

Q. Would you describe the development of the operation and maintenance expenses?

A. Yes. The projected 2017 and 2018 operation and maintenance (O&M) expenses are summarized on Statement K, pages 7 through 11, with the detail provided on pages 12 through 27.

The cost of gas, shown on page 12, uses the projected sales volumes, adjusted for losses, and the cost of gas calculated in the May 2017 Purchased Gas Cost Adjustment. The distribution loss factor of 0.45 percent represents the current loss factor.

Q. Would you describe the development of the projected other O&M expense?

A. Yes. O&M expenses were reviewed and projected by resource or cost category, some on a North Dakota only basis and some on a total Company basis. Montana-Dakota developed the O&M expenses for 2017 by reviewing current information, as well as discussions with operations personnel to determine the best information for 2017. The projections for 2018 were based on the projected 2017 data. Projected 2018 expenses are based on the Company's best estimate when changes are known or based on an inflation factor when appropriate. To establish an inflation factor, the Company based its factor on the index published by the Congressional Budget Office, the Organization for Economic Cooperation and Development, International Monetary Fund, PriceWaterhouse-Coopers, Federal Reserve and Economic Intelligence Unit. The rates were relatively consistent ranging from 1.95 to 2.60 percent and an average of 2.22 percent.

Q. Would you describe the development of the labor and benefits expense?

A. Yes. Labor expense is shown on page 13, with actual labor expense for the twelve months ended December 31, 2016 used as the starting point. The overall projected increase of 1.28 percent in 2017 includes an increase of 3.0 percent for bargaining unit employees pursuant to a negotiated union contract and 3.4 percent for non-bargaining unit employees effective in 2017. In addition, bonuses and commissions have been adjusted to reflect the elimination of retention payments and rental subsidies from the 2016 level. Incentive compensation has been adjusted to reflect targeted incentive levels as a percentage of straight time and vacation. The overall increase for projected 2018 is 2.93 percent and includes an increase of 3.0 percent for all employees.

Benefits are shown on page 14. Benefits expense consists of medical/dental insurance, pension, post-retirement, 401K, and workers compensation. Each of these items was adjusted individually. Medical/dental expense for 2017 and 2018 reflect an increase of 7.20 percent and 7.00 percent, respectively, based on premiums in effect for 2017 and projected premiums for 2018. Pension and post-retirement expense for 2017 reflect amounts agreed upon pursuant to the Settlement Agreement in Case No. PU-15-090. Pension and post-retirement expense for 2018 is based on the 2018 Actuarial Estimate adjusted to reflect the recovery of the estimated deferred balance as of December 31, 2017. The estimated deferred balance is proposed to be amortized over a three-year period. Projected 401K and other benefits expense reflect the straight time labor increase of 3.24 percent for 2017 and 3.00 percent for 2018. Workers' compensation is based on the ratio of workers' compensation expense for 2016 to per books North Dakota gas labor expense applied to 2017 and 2018 projected labor expense.

Q. Would you describe the other projected O&M expense items?

A. Yes. The projected subcontract labor expense (Statement K, page 15) for 2017 remains at the 2016 level. Subcontract labor expense for 2018 was adjusted to reflect inflation at 2.22 percent based on an average of six indices. Materials expense (Statement K, page 16) for 2017 is expected to remain at the 2016 level and increase in 2018 based on a policy change to expense computer and mobile communication equipment under $1,000 rather than capitalizing and the application of an inflation rate of 2.22 percent.

. Vehicles and work equipment (Statement K, page 17) reflect all expenses associated with the Company's vehicles and equipment, such as backhoes, skid steers and excavators, including the cost of fuel, insurance, maintenance and depreciation expense. The depreciation expense on these items is charged to a clearing account (rather than to depreciation expense), where it is then recorded in O&M expense or capitalized as part of a project as the vehicle or work equipment is used. The projected expense has been updated based on the projected plant as shown in Statement L and the proposed depreciation rates as supported by Mr. E. Robinson.

Company consumption (Statement K, page 18) is the expense for electric and natural gas consumption in Company buildings. The electric component reflects the projected volumes at rates reflecting the settlement in Case No. PU-16-666. Rates and volumes are projected to remain at the same level for 2018. The natural gas component is increased to reflect normalized volumes at current rates for 2017 and is projected to remain at that same level for 2018.

Uncollectible accounts expense (Statement K, page 19) is based on the ratio of the three-year average of net write-offs to sales and transportation revenue. This ratio was then applied to the projected 2017 and 2018 sales and transportation revenues, which results in an increase in uncollectible accounts.

Projected postage expense (Statement K, page 20) for 2017 reflects the number of customers receiving their monthly billing via electronic format as of December 2016 level adjusting for the additional postage savings for the entire year. Postage expense for 2018 is projected to increase by the Consumer Price Index of 2.40 percent.

Software maintenance (Statement K, page 21) was adjusted to reflect current levels. Per books 2016 was lower due to a change in the Company's treatment of software maintenance expense. Prior to 2016, the Company expensed software maintenance invoices as received. Generally, the invoices cover an annual period and are received in the third quarter, prior to their effective date. Therefore, invoices received in the third quarter of 2016 were treated as prepaid expenses and were amortized beginning in January 2017. Projected 2018 software maintenance expense reflects an inflation rate of 2.22 percent based on the average of six indices.

Projected building rental expense (Statement K, page 22) for 2017 has been adjusted to reflect the annualized current level of expense. The projected 2018 building rental expense reflects an inflation rate of 2.22 percent based on the average of six indices.

Advertising expense is shown on Statement K, page 23. Promotional advertising expense has been eliminated and informational and institutional advertising are adjusted to exclude advertising that is not applicable to North Dakota gas operations.

Q. Would you please continue with your explanation of adjustments to operation and maintenance expenses?

A. Yes. Industry dues reflect the projected level of industry dues and dues not specifically applicable to North Dakota natural gas operations have been eliminated.

Insurance expense reflects the current insurance level for 2017 and an increase of 5.00 percent for 2018 based on recent trends.

Regulatory commission expense, as shown on page 26, reflects the expenses to be incurred in this filing, amortized over a three-year period, and a three-year average of ongoing regulatory commission expense. In addition, it includes the expenses related to the Common and Gas depreciation studies amortized over five years. The Bismarck manufactured gas plant will be fully amortized at the end of 2017 pursuant to Case No. PU-10-589.

The items adjusted individually above represent approximately 98 percent of total North Dakota gas O&M expenses, as shown on pages 28 and 29. The remaining items, which make up approximately 2 percent of other O&M expense, were adjusted for the effects of inflation for 2017 and 2018. A 2.2 percent inflation factor, based on the average of six published inflation indices, was applied to the expenses not specifically adjusted for 2017 and 2018.

Q. Would you describe the calculation of depreciation expense?

A. Yes. Projected depreciation expense is summarized on Statement K, page 30. The calculation of depreciation expense and associated accumulated reserve for depreciation is shown on pages 31 and 32. Depreciation expense is calculated on projected plant using the average projected plant in service. AUS Consultants prepared a depreciation study, at the Company's request, for Common assets based on the plant balances at December 31, 2014 and for Gas assets based on the plant balances at December 31, 2015. Both studies are supported in the testimony of Mr. E. Robinson. Montana-Dakota is proposing to use depreciation rates that were developed in the Common and Gas depreciation studies with the following exceptions. The Common depreciation rates proposed in this filing are consistent with depreciation rates approved in the most recent electric rate case in Case No. PU-16-666. For Gas assets, the Company is proposing to utilize the rates presented in the study with the exception of FERC Accounts 376, 380 and 381. Mr. E. Robinson has supported the Cost of Removal (COR) component of the depreciation rates to be 50%, 200%, and 20%, each of which is a negative value, respectively. The Company's current COR components are negative, 40%, 140%, and 0%. While Montana-Dakota supports the AUS Consultants' study, the Company is proposing to mitigate the depreciation rate increases and, at the same time, match the COR components approved in the Company's other gas jurisdictions. Therefore, the proposed COR components used in this filing for FERC Accounts 376, 380 and 381 are, negative 30%, 175% and 5%, respectively. The depreciation rates are shown on Statement G page 1, with a summary of composite rates by function on page 2.

Q. How were taxes other than income projected?

A. Projected taxes other than income are shown on pages 33 through 35. Ad valorem taxes were calculated using the projected 2017 and 2018 plant in service balances and applying a projected effective tax rate based on the ratio of 2016 ad valorem taxes to average plant balances, excluding the acquisition adjustment, as of December 31, 2016 by function.

Projected payroll taxes were based on the ratio of payroll taxes to labor expense for 2016 and applied to the projected 2017 and 2018 labor expense to determine the projected payroll taxes.

All other taxes other than income were projected to remain at the 2016 level.

Q. Would you describe the calculation of federal and state income taxes?

A. The projected income tax calculation for North Dakota gas operations is shown on page 36. Interest is deductible for tax purposes and the projected interest expense shown on page 37 is calculated on the projected rate base using the projected debt ratio and weighted cost of debt from Statement D, page 1.

North Dakota federal and state income taxes are fully normalized, so the calculation of income taxes is made on the taxable income after interest, since any tax deductions would be fully offset by deferred income taxes.

Rate Base

Q. Would you describe the development of the projected rate base for 2017 and 2018?

A. The rate base is summarized on Statement L, page 1 and shows the 2016 actual and projected 2017 and 2018 rate base for North Dakota gas operations. Pages 2 through 22 are the supporting components of the projected rate base.

Pages 2 and 3 show the projected plant in service for 2017 and 2018. The projected plant was developed by adding the capital budget items for 2017 to the 2016 plant in service balances. Retirements, based on a three-year average of retirements by function, were deducted and the average 2017 balance was calculated. The process was repeated for 2018. The detailed capital additions by project for 2017 and 2018 are shown on pages 5 through 9. The 2018 plant additions include approximately $5.6 million for System Safety and Integrity Program (SSIP), including $2.9 million of Main Replacements and $2.7 million of Service Line Replacements. The SSIP is discussed in more detail in the testimony of Mr. Patrick Darras.

The projected accumulated reserve for depreciation is summarized on page 10. The projected reserve balances were calculated using the reserve balances at December 31, 2016, adding the calculated depreciation expense and deducting retirements based on a three-year average of retirements, as shown on Statement K, pages 31 and 32. The average 2017 balances were then calculated and the process was repeated for 2018.

Q. How were the working capital items derived?

A. The projected working capital items are shown on pages 11 through 18. Materials and supplies and fuel stocks were restated to a thirteen month average on pages 12 and 13, reflecting actual balances through April 2017 with May through December remaining at the 2016 levels.

Prepayments, which are made up of prepaid insurance, are shown on page 14. Prepayments are restated to a thirteen month average balance. The projected 2017 and 2018 balances are based on the projected 2017 and 2018 insurance expense.

The unamortized loss on debt was calculated using the balances as of December 31, 2016 and adding the calculated change for 2017, which reflects a reallocation of the balance and the annual amortization, to arrive at a balance for 2017. The 2016 and 2017 balances were then averaged to reflect the 2017 average unamortized loss on debt. The process was repeated to calculate the 2018 average unamortized loss on debt, as shown on page 15. The associated accumulated deferred income taxes are also included on page 20.

On April 1, 2017, Montana-Dakota redeemed all outstanding preferred stock. Preferred stock comprised about 1.1 percent of the capital structure during 2016 as shown in Statement D, page 1. Preferred stock has characteristics of both debt and equity. For instance, only $180,000 of the $685,000 in dividends paid each year are deductible on the Company's tax return. The quarterly dividends paid are based on a stated rate of 4.5 and 4.7 percent similar to debt.

$20 million of long-term debt issued in the first quarter of 2017 provided an opportunity to redeem the preferred stock and replace it with long term debt with a stated interest cost of 3.36 percent. At the same time, all of the interest is deductible for tax purposes which further reduces the revenue requirement. The result of the redemption is a lower overall cost of capital.

As discussed in the testimony of Ms. T. Nygard, a call premium of $600,000 was incurred upon redemption of preferred stock. The call premium has been deferred, net of tax, on the Company's books. The Company is now proposing to include this regulatory asset in its rate base and to amortize the balance over the life of the long-term debt of 15 years. An analysis has been prepared which demonstrates the overall net benefit of the redemption, inclusive of the rate base impact, is beneficial to Montana-Dakota's customers. Therefore, this item has been reflected in the revenue requirement in a manner similar to the unamortized loss on debt as shown on page 16.

New office buildings were constructed in WiIliston and Watford City. The existing office buildings were sold which resulted in a gain. The gain on the sale of both office buildings was deferred and is being amortized as authorized in Case No. PU-15-090 beginning in December 31, 2015 and is shown on page 17. The gain is being amortized over a 20 year period beginning with the month following the in service date of each of the new office buildings. The activity for 2017 is reflected and the 2016 and 2017 balances were then averaged to reflect the 2017 average balance. The process was repeated to calculate the 2018 average balance. The associated accumulated deferred income taxes are included on page 20.

During the recent expansion related to oil development in western North Dakota, the region operations experienced a lack of housing units available to meet the number of workers necessary to fill required jobs. In many cases, Montana-Dakota was able to find an individual to fill an open position but the individual was unable to acquire housing; therefore, was not able to accept the position offered to them. The Company found it was necessary to provide housing options, specifically manufactured homes, in order to be able to attract and retain employees. More recently, the number of housing units in the region has increased and employees have been able to find permanent housing. Therefore, the Company made the decision to dispose of all housing units. A loss was incurred upon disposal and the Company is proposing to amortize the loss over a twenty-year period with the unamortized balance included in the rate base as an addition as shown on page 18. In Case No. PU-16-666, the Commission approved a Settlement Agreement granting the same treatment proposed in this filing. The associated accumulated deferred income taxes are included on page 20.

Customer advances for construction are shown on page 19 and have been restated to a thirteen month average balance for 2017 and 2018, with actuals through April 2017. Several large projects included in the Company's capital additions have been identified as having an associated customer advance. The monthly customer advance balances have been adjusted to include the advance to coincide with the in service date of the project. Also, as previously mentioned, the Company accepted a Letter of Credit in lieu of a customer advance for certain projects. The Projected 2017 and 2018 Customer Advance balance has been adjusted to reflect the collection of the contribution via a Letter of Credit for two large industrial customers which are not likely to meet their volume requirements. Therefore, the total investment for the two extensions are offset by the customer advance.

Q. Would you describe how the accumulated deferred income tax balances were developed?

A. The accumulated deferred income tax balances are summarized on page 20. The projected balances were derived by adding the changes to the deferred income taxes for 2017 and 2018 to the 2016 balances and calculating the average balance.

The changes associated with book/tax depreciation differences (liberalized depreciation) are on page 21 and display the projected changes due to the plant additions as well as existing plant. The Company is required to use the Proration Method of computing deferred taxes for all test period filings in which a forecast has been used to develop the revenue requirement to comply with IRS normalization rules.

The accumulated deferred income taxes associated with the unamortized loss on debt, the preferred stock redemption, the gain on the sale of the Williston and Watford City office buildings and the loss on the sale of employee housing are shown on pages 15, 16, 17, and 18, respectively. The change in accumulated deferred income taxes associated with full normalization and the acquisition adjustment are the same as experienced in 2016.

Q. Are you proposing any changes to Rate 88 – Cost of Gas and Rate 99 – Cost of Gas Propane?

A. Yes. Montana-Dakota is proposing to change the minimum threshold for determining if a monthly adjustment will be made under Rates 88 and 99 from ten (10) cents to twenty five (25) cents. The Company expects the increase in the threshold amount will reduce the number filings by about 50 percent and, many times, the rates increase one month followed by a decrease the following month. The annual surcharge adjustment filing will be maintained; therefore, all variances between the rate charged and the actual cost of gas will continue to be deferred and trued up through the annual surcharge.

Montana-Dakota has also proposed a Firm General Contracted Demand Service Rate 74 as discussed by Ms. Bosch. Rate 88 has been updated to reflect the cost of gas to be charged for Rate 74. The Capacity Charge will be developed on an incremental pipeline capacity basis and applied to the contracted billing demand. The Cost of Gas - Commodity Charge will be based on costs applicable to firm customers, exclusive of pipeline demand charges, and will be applied to the customer's actual measured Dk for the given month.

Q. Will you now describe the revenue requirement supporting the proposed System Safety and Integrity Program Mechanism Rate 94 that is attached as Exhibit No.____(TRJ-3)?

A. Yes. Page 1 of this exhibit is a summary of the projected 2019 revenue requirement that was used by Ms. Bosch in the development of the projected 2019 rates and is based on the revenue requirements developed for 2018 and 2019.

As shown on Statement L, page 8, Montana-Dakota has included two projects related to the SSIP for the projected 2018 rate base, one in mains and one in services. Page 4 and 5 show the revenue requirement for each of these projects. The revenue requirement has been developed based on the seasonal construction close outs to plant in service. The return is based on the proposed return as shown on Statement D, page 1 and the depreciation rates are based on the proposed rates discussed earlier in my testimony. The purpose of the revenue requirement for projected 2018 is to establish a base level of revenue, which is included in the Company's rate request, and provides a base to which the actual 2018 construction spending will be trued up through the proposed SSIP Adjustment Mechanism.

Similarly, based on Mr. Darras' testimony, a revenue requirement was developed for the projected 2019 period. Each of the assumptions mentioned above was used in the development of the 2019 revenue requirement as well.

As noted by Ms. Bosch, the Company proposes to file in early 2019 for the recovery of the projected 2019 revenue requirement. The filing would include a revenue requirement true up to the actual 2018 capital spending compared to the base revenue requirement of $386,787 as established in this proceeding. All future filings will continue to reflect the base until the Company files its next general rate case.

Q. What is the additional revenue requirement calculated on Exhibit No.____(TRJ-1)?

A. Exhibit No.____(TRJ-1), which is identical to Statement J, page 3, shows the calculation of the revenue deficiency of $5,863,197 based on the projected 2018 income and rate base and using the overall rate of return of 7.542 percent from Statement D, page 1 and supported by Ms. Nygard and Dr. Gaske.

Q. Is Montana-Dakota seeking an interim increase in this case?

A. Yes, it is. As stated by Ms. Kivisto, Montana-Dakota is seeking an interim rate relief in this case pursuant to North Dakota §49-05-06.

Q. What amount of interim rate relief is the Company seeking?

A. The Company has identified an interim revenue requirement, presented in Exhibit No. ___ (TRJ-2) of $4,561,074 and Exhibit B of the Interim Application based on the 2018 projected cost of service. The return used in this projection is based on a 9.50 percent return on equity authorized in Case No. PU-15-090. In addition, the interim revenue requirement has been adjusted to remove the proposed preferred stock redemption costs and loss on sales of employee housing from the rate base. The interim revenue requirement is based on depreciation rates currently in effect.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
PROJECTED 2018

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$106,410,946	**$5,863,197**		$112,274,143
Transportation	2,197,896			2,197,896
Other	3,527,788			3,527,788
Total Revenues	112,136,630	5,863,197		117,999,827
Operating Expenses				
Operation and Maintenance				
Cost of Gas	70,913,006			70,913,006
Other O&M	21,532,698			21,532,698
Total O&M	92,445,704			92,445,704
Depreciation	9,206,297			9,206,297
Taxes Other Than Income	2,039,599			2,039,599
Income Taxes	1,876,170	2,216,376	2/	4,092,546
Total Expenses	105,567,770	2,216,376		107,784,146
Operating Income	$6,568,860	$3,646,821		$10,215,681
Rate Base	$135,450,558			$135,450,558
Rate of Return	**4.850%**			**7.542%**

1/ Statement K, Page 1.
2/ Reflects state and federal taxes at 37.8015%.

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
PROJECTED 2018
- INTERIM -

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$106,410,946	**$4,561,074**		$110,972,020
Transportation	2,197,896			2,197,896
Other	3,527,788			3,527,788
Total Revenues	112,136,630	4,561,074		116,697,704
Operating Expenses				
Operation and Maintenance				
Cost of Gas	70,913,006			70,913,006
Other O&M	21,532,698			21,532,698
Total O&M	92,445,704			92,445,704
Depreciation	8,365,365			8,365,365
Taxes Other Than Income	2,039,599			2,039,599
Income Taxes	2,185,562	1,724,154	2/	3,909,716
Total Expenses	105,036,230	1,724,154		106,760,384
Operating Income	$7,100,400	$2,836,920		$9,937,320
Rate Base	$136,370,517			$136,370,517
Rate of Return	**5.207%**			**7.287%**

Projected 2018			
Long Term Debt	43.036%	5.282%	2.273%
Short Term Debt	5.968%	2.831%	0.169%
Preferred Stock	0.000%	0.000%	0.000%
Common Equity	50.996%	9.500%	4.845%
Total	100.000%		7.287%

1/ Page 2
2/ Reflects state and federal taxes at 37.8015%.

MONTANA-DAKOTA UTILITIES CO.
SSIP REVENUE REQUIREMENT
PROJECTED 2019

	Total	Mains	Services
Depreciation Expense	$338,983	$101,811	$237,172
Ad valorem taxes	52,782	27,438	25,344
Return	603,348	316,749	286,599
Income Taxes	(221,939)	(87,626)	(134,313)
Gross up for Taxes	469,902	217,804	252,098
Less: Base	(386,787)	(178,930)	(207,857)
Total	$856,289	$397,246	$459,043

MONTANA-DAKOTA UTILITIES CO.
SSIP PLANT ADDITIONS- MAINS
2019 REVENUE REQUIREMENT

		2019 Projected											
	Total	January	February	March	April	May	June	July	August	September	October	November	December
Plant in Service		$2,886,799	$2,886,799	$2,886,799	$3,042,739	$3,354,619	$3,822,439	$4,446,199	$5,069,959	$5,537,779	$5,849,659	$6,005,599	$6,005,599
Accumulated Reserve		33,209	39,247	45,285	51,323	57,687	64,704	72,699	81,999	92,603	104,186	116,421	128,982
ADIT 1/		20,660	26,583	31,908	36,654	40,802	44,371	47,342	49,715	51,509	52,706	53,324	53,343
Rate Base		$2,832,930	$2,820,969	$2,809,606	$2,954,762	$3,256,130	$3,713,364	$4,326,158	$4,938,245	$5,393,667	$5,692,767	$5,835,854	$5,823,274
Return @ 7.542% 2/	$316,749	$17,805	$17,730	$17,658	$18,571	$20,465	$23,338	$27,190	$31,037	$33,899	$35,779	$36,678	$36,599
Expenses													
Depreciation	101,811	6,038	6,038	6,038	6,038	6,364	7,017	7,995	9,300	10,604	11,583	12,235	12,561
Ad Valorem Taxes	27,438	1,099	1,099	1,099	1,158	1,277	1,455	1,693	1,930	2,108	2,227	2,286	10,007
Total Expenses	$129,249	$7,137	$7,137	$7,137	$7,196	$7,641	$8,472	$9,688	$11,230	$12,712	$13,810	$14,521	$22,568
Income before taxes	($129,249)	($7,137)	($7,137)	($7,137)	($7,196)	($7,641)	($8,472)	($9,688)	($11,230)	($12,712)	($13,810)	($14,521)	($22,568)
Interest expense	102,560	5,765	5,741	5,718	6,013	6,626	7,557	8,804	10,049	10,976	11,585	11,876	11,850
	($231,809)	($12,902)	($12,878)	($12,855)	($13,209)	($14,267)	($16,029)	($18,492)	($21,279)	($23,688)	($25,395)	($26,397)	($34,418)
Income Taxes	$87,626	$4,877	$4,868	$4,859	$4,993	$5,393	$6,059	$6,990	$8,044	$8,954	$9,600	$9,978	$13,011
Operating Income	($41,623)	(2,260)	(2,269)	(2,278)	(2,203)	(2,248)	(2,413)	(2,698)	(3,186)	(3,758)	(4,210)	(4,543)	(9,557)
Revenue Requirement	$576,176	$32,260	$32,154	$32,052	$33,400	$36,517	$41,401	$48,053	$55,022	$60,543	$64,293	$66,273	$74,208
Less: Base 3/	$178,930	($21)	($40)	($56)	$1,262	$4,219	$8,809	$15,028	$21,541	$26,710	$30,235	$32,123	$39,120
SSIP Revenue	$397,246	$32,281	$32,194	$32,108	$32,138	$32,298	$32,592	$33,025	$33,481	$33,833	$34,058	$34,150	$35,088

1/ Balances based on monthly proration methodology.
2/ Based on projected 2018 return per Case No. PU-17-___, Statement D pg. 1.
3/ See page 4.

MONTANA-DAKOTA UTILITIES CO.
SSIP PLANT ADDITIONS- SERVICES
2019 REVENUE REQUIREMENT

		2019 Projected											
	Total	January	February	March	April	May	June	July	August	September	October	November	December
Plant in Service		$2,666,355	$2,666,355	$2,666,355	$2,810,415	$3,098,535	$3,530,715	$4,106,955	$4,683,195	$5,115,375	$5,403,495	$5,547,555	$5,547,555
Accumulated Reserve		77,359	91,424	105,489	119,554	134,379	150,724	169,348	191,012	215,716	242,700	271,203	300,466
ADIT 1/		8,258	9,937	11,446	12,791	13,967	14,979	15,821	16,494	17,002	17,341	17,517	17,522
Rate Base		$2,580,738	$2,564,994	$2,549,420	$2,678,070	$2,950,189	$3,365,012	$3,921,786	$4,475,689	$4,882,657	$5,143,454	$5,258,835	$5,229,567
Return @ 7.542% 2/	$286,599	$16,220	$16,121	$16,023	$16,832	$18,542	$21,149	$24,648	$28,130	$30,687	$32,327	$33,052	$32,868
Expenses													
Depreciation	237,172	14,065	14,065	14,065	14,065	14,825	16,345	18,624	21,664	24,704	26,984	28,503	29,263
Ad Valorem Taxes	25,344	1,015	1,015	1,015	1,070	1,180	1,344	1,564	1,783	1,947	2,057	2,112	9,242
Total Expenses	$262,516	$15,080	$15,080	$15,080	$15,135	$16,005	$17,689	$20,188	$23,447	$26,651	$29,041	$30,615	$38,505
Income before taxes	($262,516)	($15,080)	($15,080)	($15,080)	($15,135)	($16,005)	($17,689)	($20,188)	($23,447)	($26,651)	($29,041)	($30,615)	($38,505)
Interest expense	92,798	5,252	5,220	5,188	5,450	6,004	6,848	7,981	9,108	9,936	10,467	10,702	10,642
	($355,314)	($20,332)	($20,300)	($20,268)	($20,585)	($22,009)	($24,537)	($28,169)	($32,555)	($36,587)	($39,508)	($41,317)	($49,147)
Income Taxes	$134,313	$7,686	$7,674	$7,662	$7,781	$8,320	$9,275	$10,648	$12,306	$13,830	$14,935	$15,618	$18,578
Operating Income	($128,203)	(7,394)	(7,406)	(7,418)	(7,354)	(7,685)	(8,414)	(9,540)	(11,141)	(12,821)	(14,106)	(14,997)	(19,927)
Revenue Requirement	$666,900	$37,966	$37,826	$37,687	$38,885	$42,167	$47,530	$54,966	$63,138	$69,950	$74,653	$77,251	$84,881
Less: Base 3/	$207,857	($10)	($18)	($26)	$1,201	$4,357	$9,441	$16,441	$24,120	$30,541	$35,007	$37,528	$49,275
SSIP Revenue	$459,043	$37,976	$37,844	$37,713	$37,684	$37,810	$38,089	$38,525	$39,018	$39,409	$39,646	$39,723	$35,606

1/ Balances based on monthly proration methodology.
2/ Based on projected 2018 return per Case No. PU-17-___, Statement D pg. 1.
3/ See page 5.

MONTANA-DAKOTA UTILITIES CO.
SSIP PLANT ADDITIONS- MAINS
2018 BASE REVENUE REQUIREMENT

		2018 Projected											
	Total	January	February	March	April	May	June	July	August	September	October	November	December
Plant in Service		$0	$0	$0	$144,340	$433,020	$866,040	$1,443,400	$2,020,760	$2,453,780	$2,742,460	$2,886,799	$2,886,799
Accumulated Reserve		0	0	0	0	302	1,208	3,019	6,038	10,265	15,397	21,133	27,171
ADIT 1/		2,344	4,492	6,423	8,144	9,648	10,942	12,020	12,881	13,532	13,966	14,190	14,197
Rate Base		($2,344)	($4,492)	($6,423)	$136,196	$423,070	$853,890	$1,428,361	$2,001,841	$2,429,983	$2,713,097	$2,851,476	$2,845,431
Return @ 7.542% 2/	$98,488	($15)	($28)	($40)	$856	$2,659	$5,367	$8,977	$12,582	$15,272	$17,052	$17,922	$17,884
Expenses													
Depreciation	27,171	0	0	0	0	302	906	1,811	3,019	4,227	5,132	5,736	6,038
Ad Valorem Taxes	12,794	0	0	0	55	165	330	550	769	934	1,044	1,099	7,848
Total Expenses	$39,965	$0	$0	$0	$55	$467	$1,236	$2,361	$3,788	$5,161	$6,176	$6,835	$13,886
Income before taxes	($39,965)	$0	$0	$0	($55)	($467)	($1,236)	($2,361)	($3,788)	($5,161)	($6,176)	($6,835)	($13,886)
Interest expense	31,889	(5)	(9)	(13)	277	861	1,738	2,907	4,074	4,945	5,521	5,803	5,790
	($71,854)	$5	$9	$13	($332)	($1,328)	($2,974)	($5,268)	($7,862)	($10,106)	($11,697)	($12,638)	($19,676)
Income Taxes	$27,162	($2)	($3)	($5)	$126	$502	$1,124	$1,991	$2,972	$3,820	$4,422	$4,777	$7,438
Operating Income	(12,803)	(2)	(3)	(5)	71	35	(112)	(370)	(816)	(1,341)	(1,754)	(2,058)	(6,448)
Revenue Requirement	$178,930	($21)	($40)	($56)	$1,262	$4,219	$8,809	$15,028	$21,541	$26,710	$30,235	$32,123	$39,120

1/ Balances based on monthly proration methodology.
2/ Based on projected 2018 return per Case No. PU-17-___, Statement D pg. 1.

MONTANA-DAKOTA UTILITIES CO.
SSIP PLANT ADDITIONS- SERVICES
2018 BASE REVENUE REQUIREMENT

	Total	January	February	March	April	May	June	July	August	September	October	November	December
		2018 Projected											
Plant in Service		$0	$0	$0	$133,318	$399,954	$799,907	$1,333,178	$1,866,449	$2,266,402	$2,533,038	$2,666,355	$2,666,355
Accumulated Reserve		0	0	0	0	703	2,813	7,033	14,066	23,912	35,867	49,229	63,294
ADIT 1/		1,061	2,033	2,907	3,686	4,367	4,953	5,441	5,831	6,126	6,322	6,423	6,426
Rate Base		($1,061)	($2,033)	($2,907)	$129,632	$394,884	$792,141	$1,320,704	$1,846,552	$2,236,364	$2,490,849	$2,610,703	$2,596,635
Return @ 7.542% 2/	$90,584	($7)	($13)	($18)	$815	$2,482	$4,979	$8,301	$11,606	$14,056	$15,655	$16,408	$16,320
Expenses													
Depreciation	63,294	0	0	0	0	703	2,110	4,220	7,033	9,846	11,955	13,362	14,065
Ad Valorem Taxes	16,752	0	0	0	51	152	305	508	711	863	964	1,015	12,183
Total Expenses	$80,046	$0	$0	$0	$51	$855	$2,415	$4,728	$7,744	$10,709	$12,919	$14,377	$26,248
Income before taxes	($80,046)	$0	$0	$0	($51)	($855)	($2,415)	($4,728)	($7,744)	($10,709)	($12,919)	($14,377)	($26,248)
Interest expense	29,331	(2)	(4)	(6)	264	804	1,612	2,688	3,758	4,551	5,069	5,313	5,284
	($109,377)	$2	$4	$6	($315)	($1,659)	($4,027)	($7,416)	($11,502)	($15,260)	($17,988)	($19,690)	($31,532)
Income Taxes	$41,346	($1)	($2)	($2)	$119	$627	$1,522	$2,803	$4,348	$5,769	$6,800	$7,443	$11,920
Operating Income	(38,700)	(1)	(2)	(2)	68	(228)	(893)	(1,925)	(3,396)	(4,940)	(6,119)	(6,934)	(14,328)
Revenue Requirement	$207,857	($10)	($18)	($26)	$1,201	$4,357	$9,441	$16,441	$24,120	$30,541	$35,007	$37,528	$49,275

1/ Balances based on monthly proration methodology.
2/ Based on projected 2018 return per Case No. PU-17-___, Statement D pg. 1.

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

Before the North Dakota Public Service Commission

Case No. PU-17-___

Direct Testimony
of
Jordan R. Hatzenbuhler

Q. Would you please state your name and business address?

A. Yes. My name is Jordan R. Hatzenbuhler, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am a Senior Regulatory Analyst in the Regulatory Affairs Department for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties as a Senior Regulatory Analyst?

A. I assist in preparing various filings required by state commissions, class cost of service studies, and the development of rate design.

Q. Would you please outline your educational and professional background?

A. I graduated from the University of North Dakota in Grand Forks, North Dakota with a Bachelor of Accountancy degree, and I am a Certified Public Accountant (CPA). I started my career with PricewaterhouseCoopers as an audit associate and have since held multiple positions within MDU Resources Group prior to starting in my current role in 2015, including: Internal Auditor, Investor Relations Financial Analyst, and Senior Financial Reporting and Planning Analyst.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the results of the class cost of service study and to address the effect of the proposed revenue deficiency of $5,863,197 on a final basis and $4,561,074 on an interim basis, as identified by Mr. Jacobson's direct testimony, on each of the Company's natural gas rates, including the distribution of the revenue requirement to the various customer classes.

Q. What statements and exhibits are you sponsoring in this proceeding?

A. I am sponsoring Statement M, Statement N, Exhibit No. ___ (JRH-1), and Exhibit No.___(JRH-2).

Q. Would you please explain the embedded class cost of service study contained in Statement M?

A. Statement M contains a summary of the results of the embedded class cost of service study by the major rate classifications: Residential, Small Firm General, Large Firm General, Air Force Delivery (Rate 64), Small Interruptible Sales and Transportation, Large Interruptible Sales and Transportation, and the Minot Air Force Base Distribution. Statement M, pages 1 through 4 provides a report entitled "Cost of Service by Component." This report shows the total dollars and unit cost required under each rate if the projected rate of return of 7.542 percent were to be earned for the demand, energy, and customer cost components of each rate schedule.

Statement M, pages 5 through 22, is a report of the projected 2018 rate base and income statement items as allocated to each rate schedule. The allocator factors are provided in Statement M, Pages 23 through 34.

The embedded class cost of service study is based on the projected natural gas operations results for the 12 months ending December 31, 2018 as sponsored by Mr. Jacobson.

Q. What were the results of the embedded class cost of service study?

A. The overall North Dakota natural gas rate of return based on projected 2018 results is 4.850 percent. The rate of return provided by each customer class are shown below:

Customer Class	ROR
Residential Service	3.413%
Small Firm General Service	5.144%
Large Firm General Service	6.634%
Air Force Delivery Service	14.194%
Small Interruptible Sales & Transportation	16.043%
Large Interruptible Sales & Transportation	13.378%

Q. How did you determine what costs should be assigned or allocated to each class of customers?

A. The starting point was classifying the functionalized costs by FERC account for all rate base and income statement items as demand, energy, or customer related based on the component of service being provided. Demand-related costs are costs that vary with the demand imposed by the customer, energy-related costs are costs that vary with the amount of natural gas used by the customer, and customer-related costs are fixed costs driven by the number of customers served.

Next the plant, expense, and revenue items that were identified as directly related to a specific class of customers were directly assigned to the appropriate class. Finally, the remaining costs were allocated using the various allocation factors shown in Statement M, pages 23 through 34, on the basis of cost responsibility.

Q. Would you please provide an overview of the allocation process including the rationale underlying the choice of allocation factors?

A. Yes. I will start with the plant in service items on Statement M, Page 5 taken from the Gas Utility Plant in Service, Statements A and L. The allocation of distribution plant serves as the basis for allocating many of the rate base items.

Turning now to the distribution plant investment; each distribution plant account is analyzed and allocated based on the cause for the investment. Distribution mains, services, and meters represent approximately 92 percent of the total gross distribution investment; therefore, the allocation of these three accounts drives the allocation of the remaining distribution investment. The investment in distribution mains has been assigned 75 percent to the demand component and 25 percent to the customer component. The amount classified as demand related was allocated to each rate class based on the design day demand attributed to each class, and the amount classified as customer related was allocated to each rate class based on the average number of customers in each rate class.

The investment in services, service regulators, and meters is related solely to a customer connection; therefore, classified as customer related. Service regulators and meters were allocated to the rate classes based on Factor 9, which represents a meter weight for each customer class. The meter weights were derived by comparing the installed cost per meter for each rate class to the cost necessary to serve residential customers with the residential class weighted as one. The remainder of the rate base items is self explanatory with the allocation factor noted for each line item.

Q. Would you please continue your discussion of the embedded class cost of service study with an explanation of the income statement items in the study?

A. The allocation of the income statement items starts on Statement M, Page 14 with the allocation of revenues. As shown, sales and transportation service revenues are directly assigned based on the revenues produced by each rate class. The other revenues are allocated based on the source of the revenue item. Each item is shown along with the allocation factor applied.

Operation and maintenance expenses consist of: cost of purchased gas, production, distribution, customer accounts, customer service and information, sales and administrative, and general expenses are shown starting in Statement M, Page 14 as well. The cost of purchased gas is directly assigned to each class based on the gas costs included in the Pro Forma revenues. The cost of purchased gas is recovered through the gas cost tracking adjustment and is not recovered through the rates that will be established in this rate case. The remaining operation and maintenance expenses are allocated based on cost causation and typically follow the plant investment previously described in the rate base section. The remainder of the income statement reflects the allocation of depreciation expense, taxes other than income, and income taxes as denoted by each line item.

Q. Can you please explain the rate class labeled as Minot Air Force Distribution found on Statement M?

A. The Minot Air Force Distribution rate class represents the cost of service associated with the Minot Air Force Distribution system Montana-Dakota purchased in 2008. The costs associated with Montana-Dakota's ownership of this system are recovered under a contract with the Minot Air Force Base and set forth on the Air Force Distribution System Rate 65 rate schedule authorized by the North Dakota Public Service Commission in Case No. PU-06-470. Montana-Dakota has included an updated cost of service analysis in this case to demonstrate that other customers are not subsidizing this investment under the currently effective contract rate applicable to the Minot Air Force Distribution system.

Q. For what purpose has the embedded class cost of service study been used?

A. The study results have been used to guide the allocation of the revenue requirement to the various classes as well as the rate designs applicable to each customer class.

Q. What is the total revenue effect of the proposed gas rate changes?

A. The proposed interim rates will produce additional revenues of $4,560,902 or 4.2 percent annually based on the interim level of test period customers and sales, while the final proposed rates will produce additional revenues of $5,868,389 or 5.4 percent annually based on projected 2018 billing units. Exhibit No. __ (JRH-1) represents summaries by rate classifications of the proposed interim and final revenue increase on pages 1 and 2 respectively. The exhibit shows the rate number and a description along with the revenues calculated under the present and proposed rates. The amount and percentage increase are also shown for the proposed revenue increase.

Q. Would you please explain Exhibit No. ____(JRH-2)?

A. Yes. Page 1 of Exhibit No. ____ (JRH-2) depicts a bill comparison based on typical monthly consumption levels for an annual period for Residential customers. As shown in the comparison, the proposed rate structure will result in an average increase, based on final proposed rates, of approximately $2.98 per month for the typical Residential customer using 91 dk on an annual basis.

Q. What is the percentage of the proposed increase by class of customer?

A. The proposed increase to each of the classes is shown in the table below and on Statement N, page 3:

Class	*Increase*
Residential	5.9%
Firm General	5.5%
Air Force Delivery	0.0%
Small Interruptible	0.0%
Large Interruptible	0.0%
Overall	5.4%

Q. What are the objectives underlying the allocation of the increase and the rates proposed to recover the revenue requirement?

A. The embedded class cost of service study and proposed revenue allocation embody several of the recognized ratemaking objectives by their effectiveness in yielding the total revenue requirement under the fair-return standard, fairness of the specific rates in the apportionment of the total costs of service among the different consumers, and efficiency of the rate classes. Current rates yield returns in excess of the proposed rate of return in this case for many of the schedules. It appeared that the residential and firm general classes were the only classes that required increases to move these classes towards cost of service. The Company proposes no decreases at this time because the Residential rate class calls for an increase of approximately 10 percent, which is nearly double the overall increase required. Therefore, some mitigation was deemed necessary. The Company proposes to assign the overall increase (excluding Flexible Rate customers) of 5.5% to the Firm General rate class and recover the remaining increase needed from the Residential rate class. This results in a 5.9% increase for the Residential rate class, as opposed to the nearly 10% increase called for by the class cost of service study.

Q. How are you proposing to collect the allocated increase from the residential and firm general classes?

A. I am proposing to collect the entire amount of distribution revenues assigned to the Residential class (Rates 60 and 90) through the Basic Service Charge as is currently authorized. As seen on page 4 of

Statement N, the Basic Service Charge was increased to $0.7422 per day. On a monthly basis a residential customer's Basic Service Charge will increase from approximately $19.60 to $22.58, resulting in an increase of $2.98 per customer.

The proposed rates reflecting the allocated revenue increase for the Small Firm General and Large Firm General rates were established through a two step process. The first step was to establish the Basic Service Charge by considering the customer costs identified in the embedded cost of service study, as shown on page 2 of Statement M. As shown on page 10 of Statement N, the Basic Service Charge was increased to $0.70 per day for the Small Firm General rates and to $2.05 per day for the Large Firm General rates. The second step was to deduct the revenues to be recovered under the Basic Service Charge and establish the Distribution Delivery Charge by dividing the revenues remaining to be collected by the projected 2018 volumes attributable to the Small and Large Firm General rate schedules. This calculation can be seen on page 11 of Statement N.

Q. Were additional rate form changes made to rate schedules that were not allocated a revenue increase?

A. Yes. The Basic Service Charge for the Small Interruptible and Large Interruptible rate schedules were increased in consideration of the customer costs identified in the embedded cost of service study on pages 3 and 4 of Statement M. The Basic Service Charge for the Small and Large Interruptible rate schedules was increased to $190 per month and $1,500 per month, respectively. The associated Distribution Delivery rates were reduced in order for the Interruptible classes to maintain the intended revenue neutrality. The calculations supporting the proposed rates for the Interruptible classes can be found on pages 12 through 17 of Statement N.

Q. How was the proposed interim revenue requirement apportioned among the customer classes?

A. The interim revenue requirement of $4,561,074, as identified by Mr. Jacobson's direct testimony, was applied on an equal percentage basis to all rate schedules, with the exception of Large Interruptible contract customers, in order to maintain the allocation of revenues authorized in the last rate case. The interim amount will be billed as a separate line item on customers' bills based on the application of the interim percentage of 12.486 to the distribution component amounts billed. The calculations supporting the application of the interim increase to each class are provided in Appendix C to the Application for Interim Increase in Natural Gas Rates. Page 2 of Exhibit No. ___(JRH-2) shows a typical average residential bill reflecting the proposed interim increase that results in an average monthly increase of approximately $2.44.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
REVENUES UNDER CURRENT AND PROPOSED RATES - INTERIM

Customer Class/Rate	Projected 2018 Customers	Projected 2018 Dk	Projected 2018 Revenues	Total Proposed Revenue	Proposed Revenue Increase	Percent Increase
Residential - Rate 60	96,792	8,826,214	$58,201,289	$61,043,418	$2,842,129	4.9%
Firm General Service - Rate 70	15,560	8,035,663	44,071,987	45,543,560	1,471,573	3.3%
Air Force - Rate 64						
Firm	1	32,523	143,249	144,847	1,598	
Interruptible	2	457,577	1,461,611	1,474,982	13,371	
Total Air Force	3	490,100	1,604,860	1,619,829	14,969	0.9%
Small Interruptible						
Sales - Rate 71	92	572,872	2,532,810	2,636,473	103,663	4.1%
Transportation - Rate 81	63	1,104,513	870,115	978,758	108,643	12.5%
Total Small IT	155	1,677,385	3,402,925	3,615,231	212,306	6.2%
Large Interruptible						
Sales - Rate 85	0	0	0	0	0	-
Transportation - Rate 82	6	4,321,943	1,327,781	1,347,706	19,925	1.5%
Total Large IT	6	4,321,943	1,327,781	1,347,706	19,925	1.5%
Total North Dakota	112,516	23,351,305	$108,608,842	$113,169,744	$4,560,902	4.2%

MONTANA-DAKOTA UTILITIES CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - NORTH DAKOTA

Customer Class/Rate	Projected 2018 1\ Customers	Projected 2018 1\ Dk	Projected 2018 1\ Revenue	Total Proposed Revenue	Proposed Revenue Increase	Percent Increase
Residential - Rate 60	96,792	8,826,214	$58,201,289	$61,660,006	$3,458,717	5.9%
Firm General Service - Rate 70	15,560	8,035,663	44,071,987	46,481,691	2,409,704	5.5%
Air Force - Rate 64						
Firm	1	32,523	143,249	143,249	0	0.0%
Interruptible	2	457,577	1,461,611	1,461,611	0	0.0%
Total Air Force	3	490,100	1,604,860	1,604,860	0	0.0%
Small Interruptible						
Sales - Rate 71	92	572,872	2,532,810			0.0%
Transport - Rate 81	63	1,104,513	870,115			0.0%
Total Small Interruptible	155	1,677,385	3,402,925	3,402,754	(171)	0.0%
Large Interruptible						
Sales - Rate 85	0	0	0			
Transport - Rate 82	6	4,321,943	1,327,781			
Total Large Interruptible	6	4,321,943	1,327,781	1,327,920	139	0.0%
Total North Dakota	112,516	23,351,305	$108,608,842	$114,477,231	$5,868,389	5.4%

1\ Statement K, page 5.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE 60 BILL COMPARISON
RESIDENTIAL GAS SERVICE

		Present Rate			Proposed Rate				
Month	Dk	Basic Service Charge	Cost of Gas	Total	Basic Service Charge	Cost of Gas	Total	Amount of Increase	% Increase
January	16	$19.97	$64.18	$84.15	$23.01	$64.18	$87.19	$3.04	3.61%
February	15	18.04	60.17	78.21	20.78	60.17	80.95	2.74	3.50%
March	12	19.97	48.13	68.10	23.01	48.13	71.14	3.04	4.46%
April	9	19.33	36.10	55.43	22.27	36.10	58.37	2.94	5.30%
May	5	19.97	20.06	40.03	23.01	20.06	43.07	3.04	7.59%
June	2	19.33	8.02	27.35	22.27	8.02	30.29	2.94	10.75%
July	2	19.97	8.02	27.99	23.01	8.02	31.03	3.04	10.86%
August	2	19.97	8.02	27.99	23.01	8.02	31.03	3.04	10.86%
September	2	19.33	8.02	27.35	22.27	8.02	30.29	2.94	10.75%
October	4	19.97	16.04	36.01	23.01	16.04	39.05	3.04	8.44%
November	10	19.33	40.11	59.44	22.27	40.11	62.38	2.94	4.95%
December	12	19.97	48.13	68.10	23.01	48.13	71.14	3.04	4.46%
Total	91	$235.15	$365.00	$600.15	$270.93	$365.00	$635.93	$35.78	5.96%
Average Increase					$2.98	$0.00		$2.98	

RATE 60	Current 1/	Proposed
Basic Delivery Charge	$0.6443	$0.7422
Cost of Gas	4.011	$4.011

1/ Rate effective May 1, 2017

Case No. PU-17-___
Exhibit No.___(JRH-2)
Page 1 of 2

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE 60 BILL COMPARISON - INTERIM
RESIDENTIAL GAS SERVICE

Month	Dk	Present Rate 1/	Proposed Rate	Amount of Increase	% Increase
January	16	$84.15	$86.64	$2.49	2.96%
February	15	78.21	80.46	2.25	2.88%
March	12	68.11	70.60	2.49	3.66%
April	9	55.43	57.84	2.41	4.35%
May	5	40.03	42.52	2.49	6.22%
June	2	27.35	29.76	2.41	8.81%
July	2	28.00	30.49	2.49	8.89%
August	2	28.00	30.49	2.49	8.89%
September	2	27.35	29.76	2.41	8.81%
October	4	36.02	38.51	2.49	6.91%
November	10	59.44	61.85	2.41	4.05%
December	12	68.11	70.60	2.49	3.66%
Total	91	$600.20	$629.52	$29.32	4.89%
Average Increase per Month				$2.44	

Rate 60	Current 1/	Proposed
Basic Delivery Charge	$0.6443	$0.6443
Projected Cost of Gas	4.011	$4.011
Interim Rate		12.486%

1/ Rate effective May 1, 2017

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

Before the North Dakota Public Service Commission

Case No. PU-17-____

Direct Testimony
of
Stephanie Bosch

Q. Would you please state your name and business address?

A. Yes. My name is Stephanie Bosch, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Regulatory Affairs Manager for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties as Regulatory Affairs Manager?

A. I am responsible for the proper application of the Company's gas and electric rates in the Customer Care and Billing System (CC&B), the application of tariffs, and the preparation of miscellaneous rate filings.

Q. Would you please describe your education and professional background?

A. I graduated from the University of North Dakota in 1995 with a Bachelor of Business and Public Administration degree in Banking and Financial Economics. I joined Montana-Dakota in June 1997 as a Rate Clerk in the Regulatory Affairs Department and realized positions of increasing responsibility within the Regulatory Affairs Department until 2011 when I left the Company. In 2013 I returned to the Company as a Regulatory Analyst before attaining my current position in August of 2015.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the gas revenues at current rates, included in Statements E and K of this Application and the proposed rate schedules provided in Appendix B to the Application, as well as discuss two new rate schedules and other proposed changes in the Company's tariff.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission and the Public Service Commissions of Montana and Wyoming.

Q. What statements and exhibits are you sponsoring in this proceeding?

A. I am sponsoring the proposed rate schedules provided in Appendix B to the Application, with the exception of the proposed Cost of Gas Rate 88 and Cost of Propane Rate 99, which are sponsored by Mr. Jacobson.

I am also sponsoring the proposed interim rate schedules provided in Appendix A to the Interim Application.

Q. Would you please explain the calculation of the revenue at current rates included in Statements E and K?

A. Yes. The Company applied the Basic Service Charges and Distribution Delivery Charges applicable under each rate schedule and as authorized in Case No. PU-15-090, to the number of customers and level of usage identified by Mr. Shoemake to derive the revenues shown on Statement K, pages 4 and 5. Interruptible sales and transportation customers were priced at the applicable rate schedule's maximum rate per Dk, unless service is provided for under a contract rate. The Cost of Gas rates and Cost of Propane rate are reflective of the May 2017 Cost of Gas rates and Cost of Propane rate, excluding the surcharge.

Q. Please describe the first of the two new rate schedules, the System Safety and Integrity Program Adjustment Mechanism designated as Rate 94 and provided as Exhibit No. ____(SB-1).

A. As discussed by Ms. Kivisto and Mr. Darras, Montana-Dakota is proposing a System Safety and Integrity Program Adjustment Mechanism applicable to its North Dakota gas customers. The purpose of the new rate schedule is to provide a recovery mechanism for costs associated with qualifying operational and safety-related infrastructure additions and/or replacement projects to the Company's distribution system that are deemed prudent for recovery through the mechanism and not currently being recovered through the Company's rates.

Under the System Safety and Integrity Program Adjustment Mechanism (Mechanism), identified herein as Rate 94, Montana-Dakota would file annually with the Commission a portfolio of projects and costs that the Company will undertake in the upcoming plan year. A true-up will also be included in the following year's update to reflect any over or under recovery based on actual project expenditures from the preceding year plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate.

The revenue requirement, including the previous year's true-up, will be allocated to the various rate classes, excluding the Minot Air Force Base and any transmission level customer, based on each rate class' respective level of distribution or non-gas revenues authorized in the

Company's last general rate case. Each rate class' allocated costs will then be further divided by the projected customers to determine an annual cost per customer. This annual cost per customer will then be divided by 365 days to derive a System Safety and Integrity Program Adjustment Mechanism rate per day. The Company is proposing to assess the System Safety and Integrity Program Adjustment Mechanism as a per day and per month charge, dependent on the rate applicable to a customer's gas service. Customers taking service under a gas rate schedule where the Basic Service Charge is billed as daily rate (Rates 60, 70, 72, 90, and 92) will also be billed the System Safety and Integrity Program Adjustment Mechanism as a daily rate. Customers taking service under a gas rate schedule where the Basic Service Charge is stated as a monthly rate (Rates 71, 81, 82, and 85) will also be billed the System Safety and Integrity Program Adjustment Mechanism as a monthly charge.

Q. Why the proposed allocation of costs and rate structure?

A. The proposed allocation of costs to the various rate classes will maintain the rate design structure authorized in this rate case within the context of the System Safety and Integrity Program Adjustment Mechanism. This provides a consistency in the allocation, and recovery, of pipeline safety and integrity related costs between those projects the

Company is planning to undertake in 2018 (and be included in base rates) and those costs the Company is proposing to recover through the Mechanism.

Assessing the Mechanism as a fixed daily charge recognizes the system investments are fixed costs and will help lessen the under or over recovery of costs due to variances in volumes, both in the projected Dk used to develop a volumetric rate and in the recovery of costs through actual volumes. It further provides consistency for residential customers with their current gas service bill where customers pay a fixed daily rate for their gas service, excluding the Cost of Gas. The Mechanism will be shown as a separate line item on the customer's bill.

The proposed System Safety and Integrity Program Adjustment Mechanism provides a mechanism that allows the Company to proactively address pipeline integrity while potentially avoiding costly rate cases and providing customers with more gradual rate increases over time.

Q. When would the first rate be anticipated to be effective under the proposed Rate 94 tariff?

A. The Company is anticipating filing with the Commission its first System Safety and Integrity Program Adjustment Mechanism rate in Spring 2019 reflecting qualifying projected 2019 pipeline projects. To help illustrate the proposed rate structure, I have included Exhibit No. ___(SB-2) using the estimated 2019 revenue requirement discussed by Mr. Jacobson in his direct testimony. As shown, a residential customer would see an estimated increase of $0.46 a month in their bill in 2019 for the System Safety and Integrity Program Adjustment Mechanism at a rate of $0.015 per day.

Q. The Company is also proposing a Firm General Contracted Demand Service Rate designated as Rate 74 and provided as Exhibit No. ____(SB-3). Please describe the proposed tariff.

A. As mentioned by Ms. Kivisto, Montana-Dakota is proposing to implement a Firm General Contracted Demand Service Rate 74. The rate is applicable to non-residential customers with standby natural gas generators or customers who qualify under the Company's interruptible service tariffs, but have requested, and received Company approval, for firm gas service under the proposed tariff.

The purpose of the tariff is to recover capacity related costs from (1) standby use customers whose gas consumption is intermittent and do not provide adequate recovery of these costs and (2) customers who otherwise qualify for service under the Company's interruptible service rates due to their natural gas requirements but who want the option of reserving capacity for firm service. Qualifying customers requesting firm gas service under Rate 74 will need approval from the Company prior to the commencement of service under this rate in order to determine that adequate capacity is available for firm service for the requesting customer.

The proposed rate consists of four components: a monthly Basic Service Charge, a Distribution Demand Charge, a Capacity Charge, and a Cost of Gas – Commodity Charge. The Basic Service Charge reflects the proposed Basic Service Charges under the customer’s otherwise applicable service rate. The Distribution Demand Charge is a new billing component for Montana-Dakota and is designed to recover the distribution demand-related costs from these customers. Qualifying customers will identify, in their contract with the Company, the connected load (or demand Dk) which the Distribution Demand Charge will then be applied to each month. The Cost of Gas will be reflected as two separate components: a Capacity Charge and a Cost of Gas - Commodity Charge, as discussed by Mr. Jacobson. The Capacity Charge will be applied to the contracted monthly billing demand Dk and the Cost of Gas - Commodity Charge will be applied to the customer’s actual measured Dk for the given month.

Q. Please explain the calculation of the proposed Distribution Demand Charge.

A. The Company calculated the proposed Distribution Demand Charge rate of $6.51 per monthly demand Dk utilizing the results of the Company's embedded class cost of service study. As identified in Statement M, the Company's total distribution demand-related costs, excluding the Air Force, is $15,042,000. In dividing those costs by the Company's peak day deliveries of 192,668 Dk, an annual demand cost per Dk of $78.07 is calculated. This equates to a monthly rate of $6.51 per demand Dk.

Q. Would you briefly describe any additional changes the Company is proposing to its gas tariffs?

A. Yes. The Company is proposing the following changes to the gas tariffs as clearly identified in the legislative copy of the tariffs provided in Appendix B of the Application:

- The rates described by Mr. Hatzenbuhler have been incorporated into the proposed tariffs.
- Revise the Metering Requirements provisions under the Company's Interruptible Gas Rates 71 and 85 rate schedules to recognize that, while most customers are located within the Company's fixed

network system used for meter reading and therefore additional equipment is not needed for their meter data, select customers may still be required to install additional equipment for the transmission of such meter data if located outside the Company's fixed network communication system.

- Update the Temperature Sensitive Use per Customer identified on the Distribution Delivery Stabilization Mechanism Rate 87 tariff to reflect the daily base use per customer per day resulting from the corresponding rates' regression analyses performed for the normalization of firm general volumes in this case.
- Revise the following provisions included in the General Provisions Rate 100 tariff to:
    - Revise the Service Availability provision included under Section III Customer Obligations to standardize the language across all communities within the Company's service territory to reflect delivery pressure standards of four to six ounces. The Company is also proposing to identify the Company's local sales base pressures within Section V.9 Unit of Volume for Measurement of the General Terms and Conditions tariff.

- Revise the Metering and Measurement provision included under Section V General Terms and Conditions to inform customers that while a customer may install a meter for their own informational purposes, the customer meter may not interfere with the Company’s delivery of gas to the service or interfere with the Company’s meter.
- Outline the Company’s policy regarding billing adjustments in the event a customer’s gas service bill is found in error.
- Clarify the definition of unpaid balance included in the Late Payment provision.
- Increase the Returned Check Charge to $40.
- Include Pilot Relights under Utility Customer Services performed at no charge if the interruption of service was the Company’s responsibility.
- Identify the Company’s normal business hours to better advise customers as to when they may be charged overtime rates. The Company is also proposing to include language that customers will be advised that if the call for service was received after 12:00 p.m. for same day reconnection service

that over time service rates will apply if the work cannot be completed during normal working hours.

- Introduce a provision to indicate that customers requesting the installation of temporary metering facilities or services will be responsible for the direct costs associated with such facilities.
- Revise the Non-Residential Reconnection Fee for Seasonal or Temporary Customers to reduce the seasonal reconnection fee for distribution revenues collected while the customer was in-service for usage above the respective class' average annual authorized use.
- Include a minimum $30 charge in the event of unauthorized use of service by a customer.
- Revise the Employee Discount to reflect the applicability to qualifying retirees of MDU Resources and its subsidiaries only.
- There are other minor wording changes listed throughout the rate to improve the readability of the rate without modifying any conditions. These changes are clearly denoted on the tariff sheets in the legislative format.

Q. Is the Company proposing any changes to the Company’s Extension Policies Rates 119 and 120?

A. Yes. The Company is proposing to update the Levelized Annual Revenue Requirement (LARR) identified on the tariff to reflect the costs and return included in this case.

The Company is also proposing to clarify that the cost of the extension shall include all costs from the main, if applicable, up to, and including the riser. All costs after the riser will not be included in the cost of the extension.

Q. Please summarize the proposed changes to the Company’s Rate 124.

A. The Company is proposing to limit Rate 124’s applicability to the replacement, relocation, and repair of gas service lines as changes to existing service line installations will be reviewed in accordance with the Company’s Firm Extension Policy Rate 120.

Q. Did the Company incorporate the changes proposed to the Company's Transportation Service Rates 81 and 82 tariff in Case No. PU-17-194 pending before this Commission in this case?

A. No the Company did not. Montana-Dakota will incorporate any changes to the Transportation Service Rates 81 and 82 tariff ultimately authorized by this Commission in Case No. PU-17-194 in subsequent tariff submissions in this case.

Q. Does this conclude your testimony?

A. Yes.

State of North Dakota
Gas Rate Schedule

SYSTEM SAFETY AND INTEGRITY PROGRAM ADJUSTMENT MECHANISM
Rate 94

Applicability:

This rate schedule provides for a System Safety and Integrity Program Adjustment (SIA) and specifies the procedure utilized to recover the revenue requirement associated with the Company's additions and/or replacement of natural gas distribution facilities in compliance with operational, state, or federal pipeline safety programs deemed prudent by the Commission and not currently recovered through the Company's retail rates.

System Safety and Integrity Program Adjustment:

1. Costs to be recovered under the System Safety and Integrity Program Adjustment Mechanism may include operation and maintenance expenditures, depreciation, taxes, and a current return on project costs during construction. The return component of the revenue requirement calculation will include the authorized rate of return on equity from the Company's most recent general rate case and the current capital structure.

2. The System Safety and Integrity Program Adjustment Mechanism will be adjusted annually (or other period as authorized by the Commission) to reflect the Company's most recent projected capital costs and related expenses for projects determined to be recoverable under this rate schedule.

3. A true-up will reflect any over or under collection of revenue under the System Safety and Integrity Program Adjustment Mechanism based on actual program expenditures from the preceding recovery period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

4. The projected revenue requirement and true-up balance shall be allocated to each rate class, excluding transmission level customers, based on the respective rate class' percentage of distribution (or non-gas) revenues authorized in the Company's last general rate case. Each rate classes' allocated costs will then be further divided by the projected customers to determine an annual cost per customer.

SYSTEM SAFETY AND INTEGRITY PROGRAM ADJUSTMENT MECHANISM
Rate 94

5. The annual cost per customer by rate class will be divided by 365 days to derive the System Safety and Integrity Program Adjustment Mechanism rate per day. Customers being assessed a daily Basic Service Charge will be assessed the System Safety and Integrity Program Mechanism on a daily rate basis. Customers being assessed a monthly Basic Service Charge will be assessed the System Safety and Integrity Program Mechanism on a monthly rate basis.

System Safety and Integrity Program Adjustment Mechanism:

$x.xxx per day (applicable to Rates 60, 90, 70, 72, and 92)
$x.xx per month (applicable to Rates 71, 81, 82, and 85, excluding transmission level customers)

Montana-Dakota Utilities Co.
Gas Utility - North Dakota
System Safety & Integrity Program Mechanism
Proposed Rate Structure
Estimated 2019 Rider

Revenue Requirement $856,289

	Projected 2018 1/ 2/				Allocation of Costs using Proposed Rate Design					
Rate Class	Customers	Distribution Revenues	Proposed Increase	Total Dist Rev	% of Total	Allocated Costs	Cost per Customer	Daily Rate	Monthly Rate	Monthly Bill
Residential	96,792	$22,762,526	$3,458,717	$26,221,243	61.910%	$530,129	$5.48	$0.0150		$0.46
Firm General - Small	10,850	4,140,259	634,129	4,774,388	11.273%	96,529	$8.90	$0.0244		$0.74
Firm General - Large	4,710	7,645,528	1,775,575	9,421,103	22.244%	190,473	$40.44	$0.1108		$3.37
Small Interruptible	155	1,700,349	(171)	1,700,178	4.014%	34,371	$221.75		$18.48	$18.48
Large Interruptible 3/	5	236,703	139	236,842	0.559%	4,787	$957.40		$79.78	$79.78
	112,512	$36,485,365	$5,868,389	$42,353,754	100.000%	$856,289				
	3	119,891	Air Force							
	1	1,091,078	Transmission Level Customer							
	112,516	37,696,334								

1/ Statement N, Page 2 Billing Determinants and Page 3 Rate Design Results.
2/ Excludes Air Force.
3/ Excludes transmission level customer.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
Original Sheet No. 16

FIRM GENERAL CONTRACTED DEMAND SERVICE Rate 74

Availability:

In all communities served applicable to non-residential customers with standby natural gas generators and, available on an optional basis to, customers qualifying for service under the interruptible service tariffs that have requested, and received approval from the Company, for gas service under this rate.

Rate:

Basic Service Charge:

Customers otherwise qualifying for Rate 70	
For customers with meters rated under 500 cubic feet per hour	\$0.70 per day
For customers with meters rated under 500 cubic feet per hour	\$2.05 per day
Customers otherwise qualifying for Rates 71 or 81	\$190.00 per month
Customers otherwise qualifying for Rates 85 or 82	\$1,500.00 per month

Distribution Demand Charge:	\$6.51 per Dk per month of billing demand
Capacity Charge per Monthly Demand Dk:	Determined Monthly – See Rate Summary Sheet for Current Rate
Cost of Gas – Commodity per Dk:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge, Distribution Demand Charge, and Capacity Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

As specified in customer's contract. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

Date Filed: July 21, 2017 **Effective Date:**

Issued By: Tamie A. Aberle
Director - Regulatory Affairs **Case No.:**

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

NDPSC Volume 7
Original Sheet No. 16.1

FIRM GENERAL CONTRACTED DEMAND SERVICE Rate 74

Cost of Gas:

The cost of gas includes all applicable cost of gas items as defined in Cost of Gas – Natural Gas Rate 88 or any amendments or alterations thereto. The Cost of Gas component is subject to change on a monthly basis.

System Safety and Integrity Program Adjustment Mechanism –
Metering Requirements:

1. Service provided for under tariff must be separately metered from customer's other gas services.

2. Remote data acquisition equipment (telemetering equipment) required by the Company for a single customer installation for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder.

3. Customer may be required, upon consultation with the Company, to contribute towards an additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

4. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement.

General Terms and Conditions:

1. The customer agrees to contract for service under the Firm General Demand Rate 74 for a minimum period of one year.

2. The foregoing schedule is subject to Rates 100 through 124 and any amendments or alterations therefore or additional rules and regulations promulgated by the Company under the laws of the state.