MONTANA-DAKOTA UTILITIES CO.

A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-10-___

Direct Testimony
of
David L. Goodin

Q. Please state your name and business address.

A. My name is David L. Goodin 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) of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. and Great Plains Natural Gas Co. (Great Plains), also a Division 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. 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.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Electrical and Electronics Engineering from North Dakota State University and a Masters of Business Administration Degree from the University of North Dakota. I also completed the Advanced Management Program at Harvard University in 2006. My work experience includes five years as a field Electrical Engineer; five years as division Electric Superintendent overseeing crews, servicepersons, and office personnel in constructing and maintaining Montana-Dakota's electric system; six years overseeing its Electric System Operations Dispatch Center, and in 2000 I became the Vice President – Operations for Montana-Dakota. In January 2007 I was promoted to Executive Vice President of Operations and Acquisitions and in July 2007 became President of Cascade Natural Gas Company, a subsidiary of MDU Resources Group. I was additionally named President of Montana-Dakota and Great Plains in March 2008 and President of Intermountain Gas Company in October 2008. I am a Professional Engineer registered in North Dakota.

Q. Have you testified before this Commission and other state regulatory bodies?

A. Yes. I have previously testified before the Public Service Commissions of Montana and Wyoming and the Washington Utilities and Transportation Commission and submitted written testimony in proceedings before the Oregon Public Utilities Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of our North Dakota electric operations, explain our request for an electric rate increase and discuss the policies and reasons underlying the major aspects of the request. I will also address the request for an interim increase and identify the Company witnesses in this proceeding.

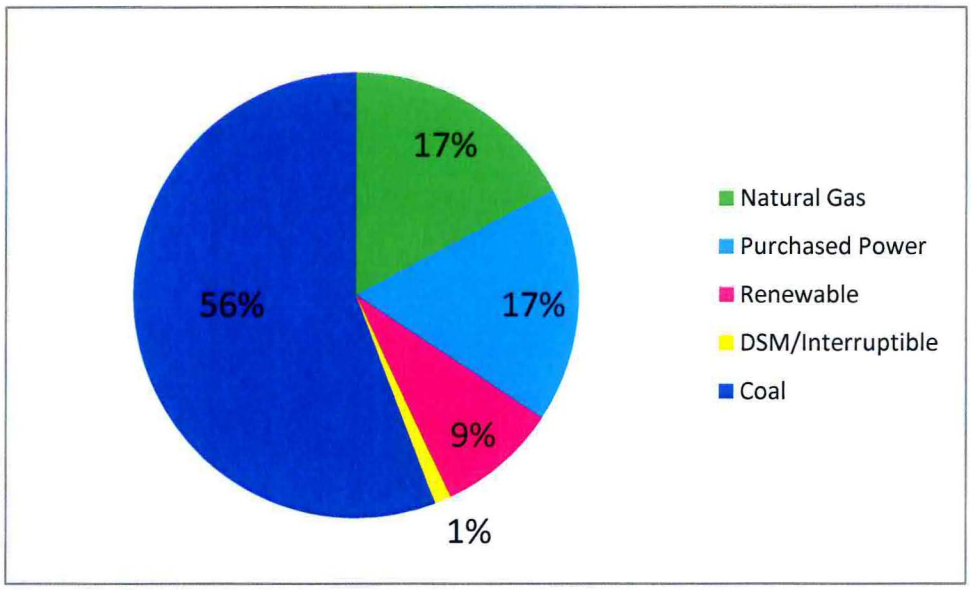
Q. Would you provide a summary of Montana-Dakota's electric operations in North Dakota?

A. Montana-Dakota's electric system consists of generation, transmission, distribution and general plant facilities serving approximately 75,350 customers in 114 communities in North Dakota. The Company's North Dakota electric service area is divided into two operating regions with regional offices located in Bismarck and Dickinson. In addition, there are a number of district offices located in communities throughout the state. As of December 31, 2009, the Company had 498 full and part time employees who live and work throughout our North Dakota electric and gas service area.

Q. Would you describe Montana-Dakota's interconnected electric system.

A. Through its interconnected electric system, Montana-Dakota serves approximately 108,000 retail customers in portions of North Dakota, Montana, and South Dakota. The Company's current capacity mix is as shown below including the addition of the 19.5 MW Cedar Hill wind

resource located in North Dakota and the 10.5 MW addition at the Diamond Willow site located in Montana as described in the Integrated Resource Plan filed with the Commission on July 1, 2009.



Q. Mr. Goodin, did you authorize the filing of the rate application in this proceeding?

A. Yes, I did.

Q. Why has Montana-Dakota filed this application for an electric rate increase?

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

Q. What is the amount of the increase requested?

A. As will be fully explained by other Company witnesses, the Company is requesting a net electric rate increase of $15,396,303 (a 14.0 percent increase over current rates) based on a projected 2010 test year

including the reductions associated with the Company's proposed change in the mechanism for sharing wholesale sales margins with its customers. The sharing mechanism, which will be discussed in greater detail by the Company's witnesses, would share the actual net margins earned by the Company from all actual wholesale sales transactions with its customers.

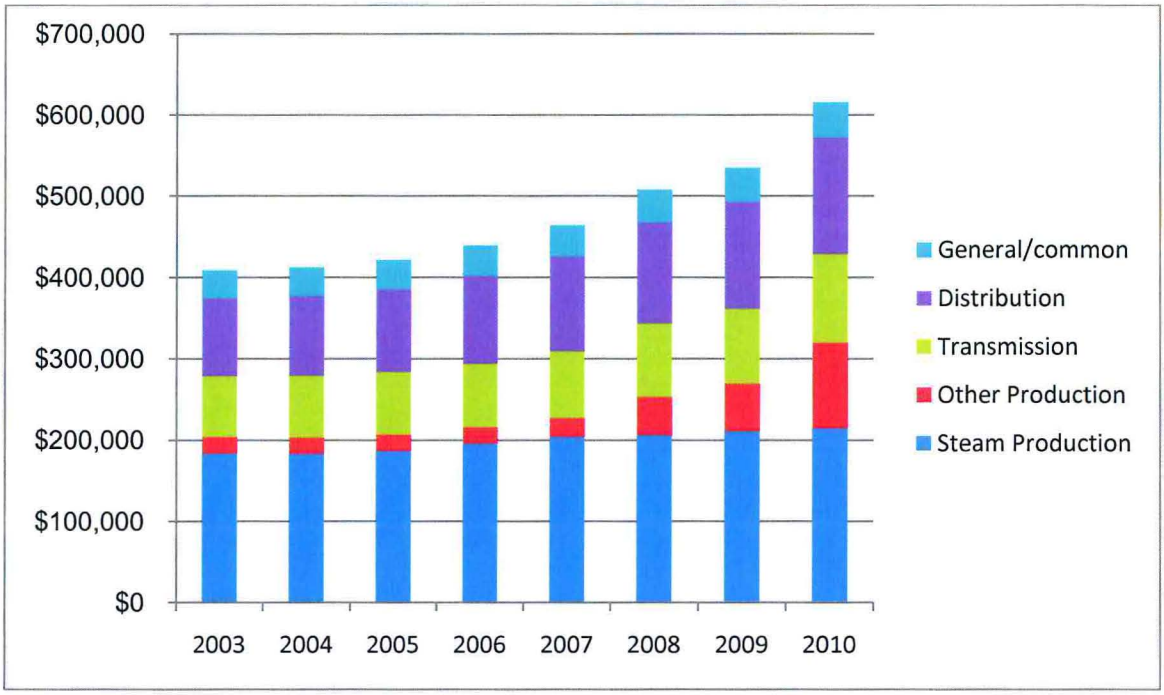
Q. How will the requested increase affect the various classes of customers?

A. The Company is proposing to allocate the overall increase of 14% to each class of customers with changes in the rate components for each schedule that move prices closer to the cost of providing service as explained more fully by Ms. Aberle.

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

A. The primary reasons for the increase in rates are:

- The increased investment in facilities, including the expansion of wind generation in the Cedar Hills and Diamond Willow projects and the associated depreciation, operation and maintenance expenses and taxes associated with the increase in investment. The table below shows the investment in electric plant assigned and allocated to North Dakota electric operations. The gross investment in North Dakota electric operations has increased by over $200 million, or approximately 50 percent, from the end of 2003 to the projected 2010 levels included in this case.



- The significant loss of wholesale sales margin in Montana-Dakota's service area. The total Company wholesale margin has decreased from $11.8 million in 2003 to just over $600,000 in 2009.
- Recovery of the deferred generation costs incurred to acquire needed generation. The amounts in this case include the costs associated with the Big Stone II plant, the Lignite Vision 21 and Milton Young III plants. If resolution of a proposed alternate recovery mechanism is approved for the Big Stone II plant costs, those costs will be withdrawn from this case.

Q. When was the last electric general rate increase for Montana-Dakota?

A Montana-Dakota's electric rates were last increased in January 2004 and reflected an increase in rates of 1.2 percent overall.

Q. Would you please explain how Montana-Dakota has been able to maintain its electric rates over the last six years?

A. Montana-Dakota has worked hard to control costs. We have been able to hold the line on our expenses by finding ways of operating our business more efficiently and taking advantage of new technologies where it makes economic sense to do so.

Q. What is the Company doing to control costs?

A. The Company continually looks for opportunities to improve efficiencies and control costs. Montana-Dakota is currently participating in a utility integration effort, along with the three other utilities within the MDU Resources Group, Inc.'s utility group (Great Plains Natural Gas Co., Cascade Natural Gas Corporation and Intermountain Gas Company). Through this effort, the four utilities will come together to pursue best practices and employ technological advances in an effort to streamline similar processes across all four utilities, while also addressing the current economic uncertainties being experienced today.

Q. What are some of the changes that have been identified to date from this integration effort?

A. A number of changes have already occurred or are in the process of being implemented. Some of the major changes are:

- *Service center consolidation.* Today, we are in the process of combining five separate call centers operated by Montana-Dakota, Cascade and Intermountain into one service center,

located in Boise, Idaho. This combined center will be responsible for all incoming customer calls for the four utilities and expected to be fully operational by the fourth quarter of 2010. Montana-Dakota's experience proves that the service quality attributed to well trained customer service representatives (CSRs) is a higher priority than the location of a CSR. Montana-Dakota's customer calls have been handled by a centralized call center since 1999 after approximately 45 offices were closed.

- *Implementation of a central credit center.* The Bismarck call center is transitioning to a centralized credit center for all four utilities where credit representatives will be available to work with customers to resolve credit problems and collection issues in addition to working with Social Services, the Low Income Energy Assistance Program and other energy assistance agencies. The Bismarck Credit Center will also operate as a back-up call center to the Boise Call Center during high call times. The Bismarck Credit Center started handling all credit and collection related calls for Montana-Dakota customers in June 2009 and the transition is expected to be completed by the fourth quarter of 2010.
- *Establishment of pay stations.* Pay stations were also established throughout Montana-Dakota's service territory in

an effort to provide convenient bill payment options and extended hours by using established Western Union vendors. Through this arrangement, payments will be electronically transmitted to Montana-Dakota, available for viewing by Montana-Dakota personnel within an hour of when the payment is made and posted to customer accounts by the next business day. The Company continues to work with established businesses throughout the Company's service territory in order to expand the number of locations at which a customer can pay her or his bill.

- *Work force reductions.* In addition to assessing the work force requirements associated with the three changes mentioned above, the Company continues to review all aspects of the utility business to ensure Montana-Dakota is operating as efficiently as possible. Work force reductions are included in the revenue requirement.
- *Comparable benefits.* The integration of processes brings with it the necessity to have comparable benefits among the utility companies. Primary changes to the benefits structure at Montana-Dakota included
    - Freezing the pension plan to significantly reduce future liability. The pension plan is applicable to

employees who commenced employment prior to January 1, 2006.

- Add a retirement contribution to the 401(k) for employees in the frozen pension plan based on age and ranging from 5 percent to 11.5 percent of base pay
- Changed the medical retiree plan to decrease future liability for current employees. Retiree medical is no longer offered to employees hired beginning January 1, 2010.
- Added two holidays for Montana-Dakota employees to bring consistency within the utility group and be in line with other utilities.
- Eliminated the employee discount for current employees effective February 1, 2010.

All of these measures will provide comparable benefits across the utility group and enable the Company to control its costs.

The Company has also refinanced essentially all of its long term debt since 2006 and has lowered its embedded weighted average debt cost from 8.766% at December 31, 2005 to a projected 6.845% at December 31, 2010.

Q. Why is Montana-Dakota investing in wind generation and other facilities and requesting an increase for those facilities?

A. The wind generation provides Montana-Dakota with diversity in its generation portfolio and the timing allowing the Company to take advantage of tax benefits and transmission availability for its customers that may not be available in the future. Mr. Neigum discusses the wind generation in more detail. The other investments in transmission facilities are required in order to maintain reliability, accommodate customer growth or to comply with environmental standards. Ms. Stomberg addresses these investments in her testimony.

Montana-Dakota has also continued to invest in its distribution facilities, including the implementation of the Automated Meter Reading (AMR) system as well as distribution substations and transformers.

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

Montana-Dakota is requesting an overall return of 9.091 percent, inclusive of a return on equity (ROE) of 11.5 percent. Dr. Gaske's analysis indicates that a 12.0 percent ROE is fully justified and supported; however, Montana-Dakota recognizes that the economic downturn has affected its service area and accordingly is seeking the same return on equity that was approved in its last rate proceeding, although less than that recommended by Dr. Gaske.

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 $7,584,309 and consists of the projected 2010 revenue requirement

with certain adjustments based on Commission guidelines as described by Ms. Mulkern.

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:

- Ms. Andrea L. Stomberg, Vice President – Electric Supply will testify on the investments in facilities and the deferred generation.
- 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 electric operations.
- Mr. Garret Senger, Vice President - Controller and Chief Accounting Officer for Montana-Dakota, will testify regarding the overall cost of capital, capital structure and overall debt and preferred equity costs.
- Mr. Darcy J. Neigum, System Operations and Planning Manager for Montana-Dakota, will testify regarding the wind generation expansion and the wholesale market changes.
- Ms. Stephanie L. Bosch, Regulatory Analyst Supervisor for Montana-Dakota will present the projected sales volumes and revenues,

- Ms. Rita A. Mulkern, Regulatory Analysis Manager for Montana-Dakota, will testify regarding the total revenue requirement and the interim revenue requirement necessary for North Dakota electric operations.
- Ms. Tamie A. Aberle, Pricing and Tariff Manager for Montana-Dakota, will testify on the rate design, the embedded class cost of service study and proposed tariff changes.

Q. Mr. Goodin, 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 in providing electric service to its customers. The proposed rates will provide Montana-Dakota the opportunity to earn a fair and reasonable return on its North Dakota electric operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

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

Before the Public Service Commission of North Dakota

Case No. PU-10-___

Direct Testimony
of
Andrea L. Stomberg

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

A. Yes. My name is Andrea L. Stomberg, 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 Vice President of Electric Supply for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. What are your responsibilities as the Vice President of Electric Supply?

A. My responsibilities include power production and transmission, system operations and planning, and electric dispatch.

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

A. I graduated from the University of Washington with a bachelor's degree in Geology, from Oregon State University with a Master of Science degree in Soils, and from the University of Mary, Bismarck, with a masters in business management. I worked for the North American Coal Corporation for ten years in surface mine permitting, reclamation planning

and oversight. I worked for Montana-Dakota for about 15 years in the environmental field prior to my current position.

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

A. Yes, I have testified before this Commission and filed written testimony with the Montana Public Service Commission and the Minnesota and South Dakota Public Utilities Commissions.

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

A. The purpose of my testimony is to provide information regarding Montana-Dakota's electric power supply and related activities that have contributed to the increase in investment that is the primary driver of the need for rate relief at this time. I will also provide support for the portion the Company's request relating to the deferred generation costs.

Q **Please describe Montana-Dakota's current power supply and status.**

A. Montana-Dakota serves the Company's electric customers in the states of Montana, North Dakota and South Dakota through an integrated electric system which has generation and transmission facilities in each of those states. Montana-Dakota's electric system has a summer peaking profile with the 2010 summer peak forecasted at 525 MW as published in the Company's Integrated Resource Plan filed with this Commission on July 1, 2009. Montana-Dakota plans to meet that demand requirement with its resource portfolio consisting of demand side management programs, company owned generation comprised of coal fired resources,

natural gas peaking capacity, renewable resources and purchased power contracts.

Power is delivered over Company-owned transmission lines, as well as lines owned by the Western Area Power Administration (Western) and Basin Electric Power Cooperative (Basin) under long-term agreements. Montana-Dakota is a member of the Midwest Independent Transmission System Operator (MISO). These transmission arrangements have allowed Montana-Dakota to efficiently serve customers throughout its service territory with minimal duplication of facilities.

Q. Would you please describe the significant capital investment made by Montana-Dakota in transmission required to reliably meet customer needs and that are included in this request?

A. Since its last filing Montana-Dakota has continued to maintain and expand its transmission system to meet the demands of its customers for reliable power. However, load growth, environmental requirements, risk mitigation and the quest for efficiency at existing facilities have driven the need for capital expenditures at a higher level than previously experienced. These investments include facilities serving both the integrated electric system as well as those required to provide service to North Dakota customers only.

Montana-Dakota shares transmission facilities with the cooperatives and Western and growth in their service areas also drives capital costs for the Company. In addition, changes in non-utility facilities

can also drive investments; the replacement of the old Memorial Bridge between Bismarck and Mandan with a new bridge is a recent example of such a cost. Montana-Dakota's transmission lines hung on the outside of the Memorial Bridge. This was not possible with the new bridge design, and Montana-Dakota elected to place the lines underneath the new bridge. The cost of this project, which was completed in 2007, was approximately $6.6 million.

Work was recently completed in the Tioga, North Dakota area, in conjunction with Basin and Western, to make modifications to a Montana-Dakota substation including a new $2.7 million transformer, ensuring continued reliable service in that area.

Continued growth in population and power demand in cities served by Montana-Dakota, especially Bismarck, Mandan, Williston and Dickinson, as well as power demand requirements in smaller cities and towns, has resulted in facilities that served reliably for years becoming fully utilized and unable to accommodate more demand. Some parts of Montana-Dakota's system are over 50 years old and are simply wearing out. This has resulted in the need to rebuild or upgrade substations and lines to ensure continued reliable service. Montana-Dakota has replaced transformers in numerous small towns throughout North Dakota to continue to reliably serve growing electric load in those areas. Montana-Dakota is building a new 230/115 substation north of the Heskett Station to support growing loads. Portions of this $10.6 million substation used to

serve the integrated system will be operational in 2010. Also in Mandan, Montana-Dakota is constructing a $1.7 million distribution substation to support growth in this area. Other substation and transmission projects undertaken from 2002 to 2006 include:

- Bismarck- 26th and Expressway conversion to higher voltage
- New Turnpike Avenue substation in Bismarck for the Pinehurst retail load
- New Cabin Creek substation located in Montana to support the western portion of the integrated system.
- Beulah-Heskett 115 kV line rebuild
- Southeast Bismarck 115 kV line rebuild/upgrade.

Investment associated with these projects was approximately $5.8 million.

Q. Describe some of the significant capital projects associated with Montana-Dakota's generation facilities.

A. At Montana-Dakota's power plants, in addition to routine maintenance and replacements, numerous other projects have been undertaken since the last electric rate filing. These projects are substantial in size and have been required by environmental regulations, recommended by the insurance carrier to minimize risk, made to improve operating efficiencies, or needed to sustain generation facility operation.

Montana-Dakota's need to meet its customer's load requirements as efficiently as possible and participation in the MISO markets drive the company to seek any available efficiency from existing generation.

Montana-Dakota has a long history of making incremental efficiency improvements to reduce fuel costs and emissions. Between 2003 and 2009, these improvement projects include:

- Replacement of process control systems
- Installation of variable frequency motor drives
- Turbine component modifications and retrofits
- Generator excitation system replacement.

These efficiency projects represent $14.2 million of investment during the period.

To ensure the most cost effective compliance with environmental regulations, Montana-Dakota has conducted numerous studies and tests, and has installed emissions control equipment where needed. The environmental projects completed between 2003 and 2009 include:

- Mercury monitoring system installations
- Mercury emissions control testing
- Lewis & Clark Station mercury emissions control system installation
- Big Stone Plant particulate emissions control system installation
- Combustion turbine fuel oil spill prevention and containment.

These environmental projects account for $12.7 million of investment during the period noted.

Montana-Dakota has installed additional fire detection and suppression systems to mitigate the fire risk to the generation facilities. Redundant equipment has been purchased to provide a back up for the

loss of critical, long-lead time equipment such as transformers. Improved over-speed protection equipment has been installed to better protect the turbine and generator equipment. From 2003-2009, these risk reduction projects accounted for $3.1 million of investment.

To ensure sustained operation of the generation facilities a number of other large projects were undertaken from 2005-2009. These projects include.

- Generator rewind
- Switch gear replacements
- Replace Heskett #2 FD fan motor
- Glendive Unit 2 natural gas compression equipment additions
- Glendive Unit 2 fuel oil heating equipment installation

These other operation sustaining projects account for $6.9 million of investment during the period.

Additionally, necessary work on the turbine and generator, and boiler element and header replacement at Heskett Station Unit 1 will be completed in 2010, after being deferred and rescheduled to allow the work to be completed at a time when labor is expected to cost less, and to extend the schedule in an effort to avoid overtime charges. The cost of this project is estimated at $3.56 million, and should allow that plant to continue to achieve exceptional capacity factors and reliability.

Montana-Dakota also installed and commissioned a 2 Mw diesel engine driven portable generator in 2004, accounting for an investment of

approximately $335,000. Other significant new generation investment includes Montana-Dakota's two wind generation facilities and the Glen Ullin waste heat recovery unit, which will be discussed in detail by Mr. Neigum.

Q. Describe Montana-Dakota's request for rate recovery of amortized costs associated with securing new electric generation resources.

A. The costs related to Montana-Dakota's efforts in securing new electric generation fall generally into the following cost categories: engineering, project development, permitting, legal, other expenditures, and Allowance for Funds Used During Construction ("AFUDC"). The total costs include $2.1 million associated with the Lignite Vision 21 (LV21) Project, $13.9 million associated with the Big Stone II project, and $332,000 associated with the Milton R. Young III Project.

Q. Why should Montana-Dakota's rates include costs for the Lignite Vision 21 and the Milton R. Young III projects?

A. Montana-Dakota had a long-term power purchase contract for 66 MW that expired in October, 2006. This power purchase contract accounted for nearly 20 percent of Montana-Dakota's base load capacity. Given the magnitude of this resource, Montana-Dakota sought new resources to replace the contract and to meet Montana-Dakota's retail customers' projected requirements. This included pursuing extension of the contract, preliminary discussions with OTP regarding the possibility of participating in a second unit at the Big Stone generation station site, and

evaluation of construction of gas turbines and wind resources. At about the same time, the State of North Dakota proposed its LV21 program, and Montana-Dakota began to evaluate the development of a 500 MW coal fired unit in North Dakota under that program. A possible North Dakota resource was an attractive option to include in evaluations seeking the best new resource to meet the long term needs of Montana-Dakota's customers.

Having a partner to utilize much of the output of the proposed 500 MW LV21 plant was essential, as Montana-Dakota's projected power and energy requirements, even including anticipated load growth, were not this large. When the Company's efforts to locate such a partner were unsuccessful, the plant design was downsized, ultimately to 175 MW. As this size plant was under evaluation, Montana-Dakota was approached again about participating in Big Stone II. Preliminary engineering and pricing estimates from the LV 21 projects made it clear that the economies of scale achieved by the larger proposed Big Stone II plant were significant compared to a smaller plant. There were additional economies available from the location of Big Stone II next to the existing Big Stone plant, as well as cost savings to be recognized at the existing plant. Because of the overwhelmingly favorable economics of the Big Stone II project relative to the LV21 plant, Montana-Dakota discontinued further work on this plant design.

Montana-Dakota knew from projected load growth analysis that even with ownership of 116 MW of the Big Stone II plant, additional capacity would be required almost as soon as that plant became commercial. Montana-Dakota approached Minnkota Power Cooperative about ownership in a possible new 250-500 MW multi-owner unit located at the Milton R. Young plant near Center. This unit was expected to become commercial in the 2010-2015 time frame, which fit well for a resource to succeed the Big Stone II, expected to be on-line in 2011. Montana-Dakota participated in discussions and preliminary engineering studies including technology, fuel availability and transmission, for about three years- 2005 to 2007. At that time other participants determined to indefinitely suspend further effort on this project for a variety of reasons. Because of current conditions make it is doubtful that further effort will be given to the project in the near future, Montana-Dakota believes it is appropriate to amortize the costs incurred in the preliminary studies of the project.

Both LV21 and Milton R. Young III, along with the Big Stone II plant, were potential regional base load power resources Montana-Dakota evaluated to provide power to its customers, faced with the expiration of a significant contract and steady customer demand growth.

Q. Would you describe why Montana-Dakota discontinued its development efforts for Big Stone II and now seeks recovery of development costs associated with the Big Stone II plant?

A. Yes. The Big Stone II project was a proposed multi-owner coal-fired generating plant to be located at the site of the existing Big Stone Generating Plant near Big Stone City, South Dakota. At the time that Otter Tail Power Company (OTP) withdrew from the project in September 2009, Montana-Dakota had a 26.54 percent share of the project and a corresponding responsibility for shared project costs.

In June of 2005, Montana-Dakota entered into project agreements with six other utilities for purposes of pursuing the project. At that time, the participants applied for the necessary permits, and began preliminary engineering and other development work for the project. The Commission issued an Advance Determination of Prudence for Montana-Dakota's participation in the project in August 2008, in Case No. PU-06-482, for a minimum of 121.8 MW up to a maximum of 133 MW and proportionate ownership share of the associated transmission additions. The Commission's order was based on an updated analysis by the Big Stone II participants for the cost of a 500 MW to 580 MW facility with an on-line date of mid-2013. Other permits were received from the South Dakota Public Utilities Commission ("SDPUC"), who approved the project Site Permit in July 2006, and the Minnesota Public Utilities Commission ("MPUC"), who issued a Certificate of Need ("CON") for the Big Stone II transmission lines in March 2009. The project also obtained a water allocation permit, the air quality permit, other necessary permits, and completed a Federal Environmental Impact Statement for the project. The

plant was initially permitted as a nominal 600 MW plant, and was expected to be commercial in 2011. Montana-Dakota has incurred approximately $14.3 million for the permitting, engineering and other development activities for the project to date. The North Dakota jurisdictional share of the total costs is 69.351586 percent or approximately $9.9 million.

On September 11, 2009, OTP withdrew from further participation in the project. Montana-Dakota was one of four participants remaining after OTP withdrew from the project. The remaining participants actively sought, but were unable to obtain commitments from new project participants. Lacking new participants to replace OTP, on November 2, 2009, the project participants determined it was no longer feasible to continue the development of the Big Stone II project at a size and cost that was permitted and would be economically efficient.

Q. Why should Montana-Dakota's customers pay for plant development costs that did not ultimately result in a resource providing service to customers?

A. The plant development costs were a necessary cost associated with Montana-Dakota's continuing effort to secure needed new electric generating resources to serve its customers. Because the efforts were in furtherance of potential long term capital projects, the costs associated with those efforts were properly capitalized. In each instance, Montana-Dakota efforts as well as the associated costs were prudently incurred. Montana-Dakota pursued the Big Stone II project after determining that it

was a prudent long-term source of reliable electricity for its customers. It made that determination after it studied an alternative generation source located in North Dakota that was supported by the State of North Dakota. The Commission agreed with Montana-Dakota's determination as evidenced in its Order issued on August 27, 2009 in Docket No. PU-06-482 finding that Montana-Dakota's investment in Big Stone II was reasonable and prudent to ensure reliable electric service to their customers. In that proceeding, the Commission questioned whether Montana-Dakota had prudently and thoroughly studied potential generation resources located in North Dakota. When due to changing circumstances it became clear that the Big Stone II project was not likely to be constructed, the plant participants discontinued development of the project.

Montana-Dakota seeks recovery of the amortization of the costs that were prudently incurred toward its efforts in securing generating resources for its customers, although unfortunately, the plants will not be built.

Q. Would you please explain future supply plans given the demise of the plant development you just described?

A. Yes. Montana-Dakota has secured a purchased power agreement that along with existing resources will serve to meet customer needs through May 31, 2015. The Company is currently analyzing other supply options that are reliable and cost-beneficial to meet the electric

customers into the future.

Q. Does that complete your direct testimony?

A. Yes, it does.

Exhibit No.___(JSG-1)

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

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

CASE NO. PU-10-____

PREPARED DIRECT TESTIMONY OF

J. STEPHEN GASKE

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

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

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

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

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

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

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

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

Q3. Have you presented expert testimony in other proceedings?

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

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

I. INTRODUCTION

A. Scope and Overview

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

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

B. Company Background

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

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

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

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

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

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

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

II. FINANCIAL MARKET STUDIES

A. Criteria for a Fair Rate of Return

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

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

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

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

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

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

1. commensurate with returns on enterprises with corresponding risks;

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

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

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

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

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

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

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

Q10. How is the cost of common equity determined?

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

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

B. Interest Rates and the Economy

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

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

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

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

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

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

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

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

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

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

C. Discounted Cash Flow ("DCF") Method

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

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

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

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

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

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

where:

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

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

D. Flotation Cost Adjustment

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

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

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

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

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

E. DCF Study of Electric Utility Companies

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

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

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

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

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

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

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

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

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

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

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

F. Second-Stage Retention Growth Analysis

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G. Basic DCF Analysis

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

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

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

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

H. Risk Premium Analyses

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

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

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

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

I. Alternative Equity Investment Analysis

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

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

2 2009 Ibbotson SBBI Valuation Yearbook, pg 23

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

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

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

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

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

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

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

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

J. Relative Risk Analysis

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

III. SUMMARY AND CONCLUSIONS

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

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

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

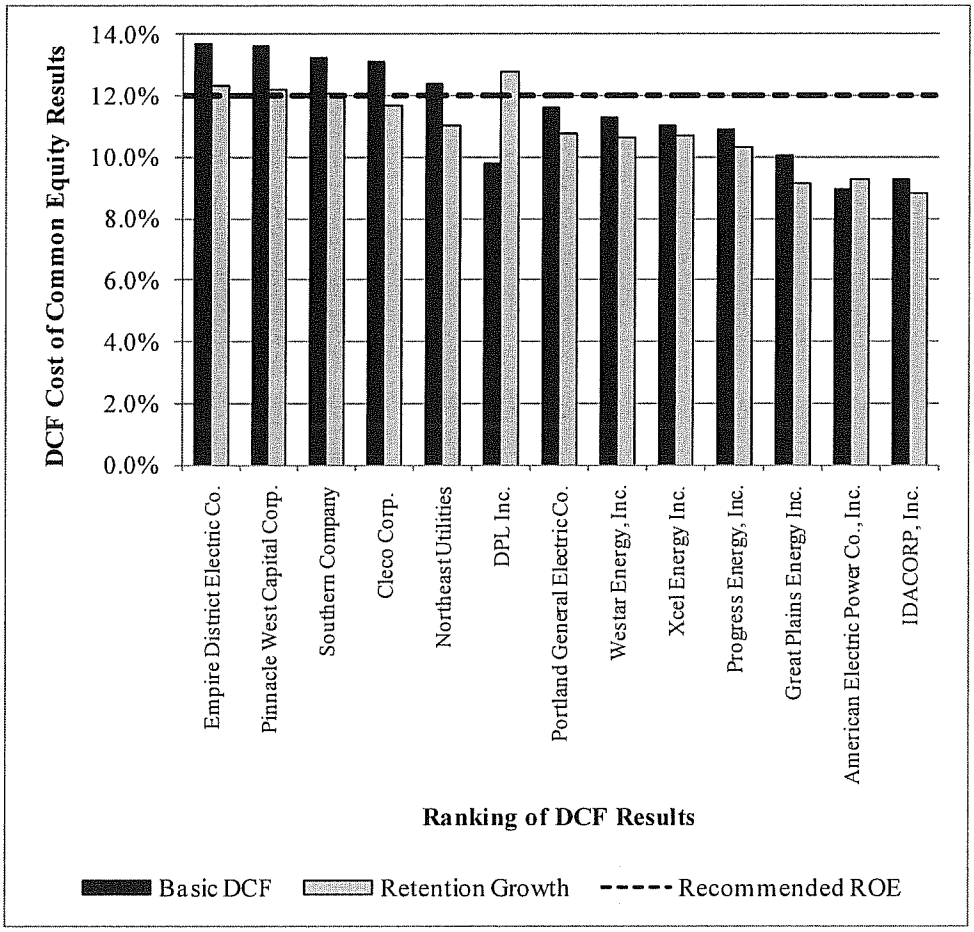
My second-stage retention growth analysis indicates a median cost of common equity capital of 10.8 percent and a 3rd Quartile return of 12.1 percent. Because

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

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

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

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



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

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

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

Q42. Does this conclude your Prepared Direct Testimony?

A. Yes.

Montana-Dakota Utilities Co.

General Economic Statistics

1980-2009

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

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

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

Montana-Dakota Utilities Co.

Bond Yield Averages
January 2007 - March 2010

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

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

Montana-Dakota Utilities Co.

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

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

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

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

Montana-Dakota Utilities Co.

Selected Electric Utility Proxy Companies
Fiscal Year 2009 Operating Data

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

Sources: 2009 10-Ks

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

Montana-Dakota Utilities Co.

Bond Ratings of
Selected Electric Utility Proxy Companies

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

Source: Bloomberg & SNL

Montana-Dakota Utilities Co.

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

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

Source: Bloomberg

Montana-Dakota Utilities Co.

Projected Earnings Retention Growth Rates for Selected Electric Utility Proxy Companies

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

Montana-Dakota Utilities Co.

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

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

Source: Zacks.com and page 4.

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

Montana-Dakota Utilities Co.

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

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

Montana-Dakota Utilities Co.

Basic DCF Calculation
for Selected Electric Utility Proxy Companies

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

Montana-Dakota Utilities Co.

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

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

Source: 2009 10-Ks

Montana-Dakota Utilities Co.

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

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

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

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

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

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

Before the North Dakota Public Service Commission

Case No. PU-10-___

Direct Testimony
of
Garret Senger

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

A. Yes. My name is Garret Senger and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Vice President, Controller and Chief Accounting Officer (CAO) for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. and Great Plains Natural Gas Co., also a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties?

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

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 a Masters in Business Administration. I started my career with Montana-Dakota in 1985 as a financial analyst in the Financial Reporting area and during my tenure with the Company have

held positions of increasing responsibility, including Supervisor of Financial Reporting, Manager of Financial Forecasting, Manager of Financial Reporting & Planning, Director of Accounting and Controller.

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

A. Yes, I have testified before the Wyoming Public Service Commission and submitted written testimony in proceedings before the South Dakota Public Utilities Commission and the Montana Public Service Commission.

Q. Are you familiar with the territory served by Montana-Dakota and the facilities of the Company utilized in providing electric service?

A. Yes, I am.

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

A. I am responsible for presenting Statement A, Statement B, and Statement F.

Q. Were these statements and the data contained therein prepared by you or under your supervision?

A. Yes, they were.

Q. Are they true to the best of your knowledge and belief?

A. Yes, they are.

Q. Would you describe Statement A and Statement B?

A. Statement A, pages 1 and 2 show Montana-Dakota's balance sheet as of December 31, 2008 and December 31, 2009, with notes to the

balance sheet following. Statement B consists of Montana-Dakota's income statement for the twelve months ended December 31, 2009. These statements have been prepared from the Company's books and records that are maintained in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

Q. Would you please explain Statement F?

A. Statement F shows the utility capital structure of Montana-Dakota for the twelve months ended December 31, 2009 and the projected capital structure for 2010. Statement F 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 9.091%. As explained later, as a result of the Company's efforts to reduce its long term debt costs, this overall rate of return is a reduction from the overall rate of return adopted for use in the Company's most recent electric rate proceeding in 2003, Case No. PU-399-03-296. The basis for the requested 11.50% return on common equity contained within the overall requested rate of return is supported by the testimony of Dr. J. Stephen Gaske but also recognizes the current economic environment. I note that this is the same return on equity adopted for use in Case No. PU-399-03-296.

Page 1 of Statement F summarizes the actual electric utility capital structure at December 31, 2009 and the projected capital structure and the related utility costs of capital for 2010. As shown on page 1, the

components of the 2010 projected overall annual rate of return, which are used by Ms. Mulkern to calculate the revenue requirement, are:

	Weighted Cost of Capital
Long Term Debt	2.891%
Short Term Debt	0.079%
Preferred Stock	0.107%
Common Equity	6.014%
Required Rate of Return	9.091%

The debt costs reflected on Statement F, page 1 represent the actual weighted embedded costs of the long-term debt at December 31, 2009 and that projected to be outstanding at December 31, 2010 and is supported by Statement F, Schedule F-1. In calculating the debt costs the "Yield-to-Maturity" method (also referred to as the Internal Rate of Return ("IRR") method) is used to determine the total cost for each respective debt issue as presented on Schedule F-1, page 2 of 5 and page 3 of 5. The yield-to-maturity calculation of each debt issue outstanding gives consideration to the stated rates of interest being paid on such debt, the timing of the interest payments, related issuance expenses, underwriters' commissions, the discount or premium realized upon issuance and the amortization of losses on bond redemption transactions.

Statement F, Schedule F-2, supports the cost of Montana-Dakota's preferred stock capital, representing the weighted cost of the issues at December 31, 2009 and projected to be outstanding at December 31, 2010.

Statement F, Schedule F-3, supports the Company's utility common

equity balance at December 31, 2009, and the projected balance as of December 31, 2010.

Q. How does the Company finance its electric 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, adequate 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 is making significant capital expenditures for new plant investment, including new renewable resources as mentioned in the testimony of Mr. Goodin. 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 targeting a 50/50 debt to equity ratio capital structure. Capital expenditure investments are financed through a mix of internally generated funds, the utilization of its short term credit line and the issuance of additional debt and equity financing as required to maintain its targeted capital ratios and finance its combined utility operations. In 2009, the Company obtained $29 million of common equity through new stock issuances between July and October. Also In 2009 the Company issued $50 million of unsecured senior notes in two $25 million private placements with a seven year maturity, at interest rates

of 6.66% and 6.61% respectively. In 2008 through a private placement the Company issued $100 million of 10 year unsecured senior notes at an interest rate of 6.04%.

Since 2006 the Company has refinanced essentially all of its long term debt and has lowered its embedded weighted average debt cost from 8.766% at December 31, 2005 to a projected 6.845% at December 31, 2010. The mix of securities employ various maturity dates in order to provide flexibility and mitigate refinancing risks. The Company does not plan to issue additional long term debt prior to December 31, 2010 but anticipates adding $15 million of equity in late 2010, again to achieve and maintain the targeted 50/50 capital structure.

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

A. Page 1 is a summary showing the Company's long-term debt at December 31, 2009 and cost of debt, and it shows the projected long-term debt and associated costs for 2010. Page 2 shows the cost and the debt balance by issue at December 31, 2009, and page 3 shows the projected cost and the debt balance by issue at December 31, 2010.

Q. How did you derive the projected cost of debt as for 2010?

A. The projected cost of debt for 2010 is based upon the yield to maturity of each debt issue outstanding.

Q. Would you please describe Statement F, Schedule F-1, page 4 and explain the amortization method utilized?

A. Page 4 reflects the detail by issue of the annual amortization of net

discounts (losses) and unamortized issuance expenses on 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 same calculation as is used by the Company for accounting purposes.

Q. Would you please describe Statement F, Schedule F-1, page 5?

A. Page 5 presents the projected average short term debt balance for 2010 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 F, Schedule F-2 show?

A. Page 1 presents the preferred stock balances at December 31, 2009 and the projected balances for December 31, 2010. The anticipated weighted cost of preferred stock is also shown. Page 2 sets forth the various preferred stock issues outstanding at December 31, 2009 and page 3 sets forth the projected issues outstanding at December 31, 2010.

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

A. Page 1 presents the common equity balance at December 31, 2009 and the projected balance for 2010 reflecting the projected activity in the balance.

Q. Why did the Company defer the costs related to the study of future

generation for Lignite Vision 21 (LV21) and Milton R Young III when these projects did not continue and not charge them to expense in the year the projects ceased?

A. As discussed by Ms. Stomberg, both LV21 and Milton R. Young III were potential regional base load power sources Montana-Dakota evaluated to provide power to its customers. The plant development costs for future generation were a necessary cost associated with the development of Montana-Dakota's next generating facility and should be recovered from customers. The total costs incurred to date including AFUDC include $2.1 million for Lignite Vision 21 and $332,000 for Milton R. Young III. These costs were incurred to study the development of future generation. While both of projects did not move forward these costs were deferred and included with the BS II costs into a construction work order designated as future generation costs. All these costs were viewed by the Company as prudently incurred costs necessary to provide future generation. Many events unfolded outside of the Company's control that drew these projects to a close as stated in Ms. Stomberg's testimony. Upon the determination not to proceed with Big Stone II these costs were subsequently transferred to a regulatory asset and a filing was made in Montana, North Dakota and South Dakota requesting an accounting order to defer these costs until the next general rate case. Accounting orders were approved in Montana and South Dakota.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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

Before the Public Service Commission of North Dakota

Case No. PU-10-___

Direct Testimony
of
Darcy J. Neigum

Q. Please state your name and business address.

A. My name is Darcy J. Neigum 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 System Operations and Planning Manager of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

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

A. I have manager responsibility for the evaluation and development of new generation resources as well as overseeing the day-to-day operations of the electric control center and system operations planning department. The system operations planning department is responsible for electric resource planning and expansion studies for the Company.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Electrical and Electronics Engineering from North Dakota State University as well as a Masters of

Business Administration from the University of Mary. My work experience includes four years as a nuclear plant operator for Westinghouse Electric, three years of experience as a plant engineer for a coal-fired plant in North Dakota, and eleven years of generation development and operational responsibilities which included coal-fired, gas-fired, and renewable generation sources. Over the last ten years, I have been responsible for project management and construction of a 220 MW gas-fired generator in Brazil, a 43 MW gas-fired generator in Montana, a 120 MW coal-fired generator in Montana, 30 MW of wind generation in Montana, 20 MW of wind generation in North Dakota, and a 5 MW heat-recovery generation project in North Dakota. I was also responsible for executive oversight of the operation and technical support for MDU Resources Group's independent power generation business unit prior to its sale in 2007.

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

A. The purpose of my testimony is to document the changes in wholesale sales that Montana-Dakota has experienced as a result of its participation in the Midwest ISO Energy Market and to describe the new resource additions that Montana-Dakota has made with respect to supply side generating stations over the past five years.

Q. Please describe the changes in wholesale sales that Montana-Dakota has experienced since 2003?

A. The expiration of a long term purchase contract with Basin Electric occurring in October 2006 coupled with the startup of the Midwest ISO Energy Market on April 1, 2005, significantly changed Montana-Dakota's

opportunities for wholesale sales of excess electric energy. Montana-Dakota's historical ability to enter into traditional bilateral arrangements was replaced with day ahead and real-time offering of available energy into the Midwest ISO Energy Market. The Midwest ISO Energy Market dispatches all available generation resources to meet system reliability requirements and minimize the purchased price of energy to load serving entities on a day ahead and real time basis.

Since the startup of the Midwest ISO Energy Market, Montana-Dakota has seen a drop in wholesale sales as compared to the pre-energy market days. The majority of Montana-Dakota's wholesale sales occurs during off-peak system hours and come from the sale of coal-based generation not utilized to serve Montana-Dakota customer load.

The table below is a summary of Montana-Dakota's historical wholesale sales showing the MWh volumes, revenue, margin and margin per MWh from 2003 through 2009 and the decline discussed above.

Wholesale Sales	2003	2004	2005	2006	2007	2008	2009
MWh	841,637	821,516	615,220	483,943	165,638	223,777	90,788
Revenue	$24,438,532	$26,469,193	$24,136,379	$6,138,964	$5,700,088	$8,043,463	$2,239,005
Margin	$11,752,321	$13,548,491	$15,747,791	$9,847,352	$3,286,769	$4,593,278	$604,256
Margin per MWh	$13.96	$16.49	$25.60	$20.35	$19.84	$ 20.53	$6.65

During the same period of 2003 to 2009, Montana-Dakota's retail sales have increased by an average of 61,140 MWh per year or 2.6 percent per year. This increase in customer load and the loss of the AVS-II contract has decreased the amount of energy that Montana-Dakota has available for wholesale sales.

With the financial market collapse and corresponding demand destruction in parts of the Upper Midwest and Midwest ISO footprint, Montana-Dakota's wholesale sales dropped significantly in 2009 as the average Midwest ISO load dropped five percent or more. The installation of intermittent, primarily wind, generation resources in the Midwest ISO footprint has also reduced Montana-Dakota's ability to make off-peak wholesale sales. This additional off-peak generation has pushed typically base load coal-fired generation down to minimum generation levels during off-peak periods when Montana-Dakota historically saw its greatest opportunity for wholesale sales. In 2009, Montana-Dakota saw frequent minimum generation events and negative system pricing during off-peak periods during the shoulder months and weekends. As of October 2009, the Midwest ISO had a total installed wind capacity of 7,472 MW. This number will continue to increase until the renewable portfolio standard targets for the Midwest ISO load are met.

The Midwest ISO's Energy Market was replaced by the Midwest ISO's Ancillary Service Market (ASM) on January 6, 2009. The startup of the ASM reduced the amount of generation resources held in reserve for regulation, spin, and supplemental requirements by over 1,000 MW

according to the Midwest ISO. This allowed additional generation to access the energy market and further reduced Montana-Dakota's opportunities for wholesale sales.

Montana-Dakota has offered its generation units capable of supplying regulation, spin, and supplemental into the ASM market but has seen minimal revenue from offering these services. Going forward, Montana-Dakota expects to see continued decreased wholesale sales and margins as compared to historical levels. For 2010, based on forecasted plant outages and unit availabilities, Montana-Dakota is forecasting wholesale sales of 122,768 MWh, an annual margin of $667,752, and an average margin per sale of $5.37 per MWh.

Q. What generating resource additions has Montana-Dakota made since 2003?

Since 2003, Montana-Dakota has made several new generating resource additions including: a 19.5 MW Wind Project named Diamond Willow which commenced commercial operation in February of 2008, a 5.3 MW heat recovery generating station named Glen Ullin Station #6 which commenced commercial operation in July of 2009, a 19.5 MW Wind Project named Cedar Hills which is scheduled to begin commercial operation in June of 2010, and a 10.5 MW expansion to the Diamond Willow Wind Project which is scheduled to begin commercial operation in June of 2010.

All resource additions were included in Montana-Dakota's most recent filed Integrated Resource Plan dated July 1, 2009.

Q Please describe the Diamond Willow Wind Project?

A. The 19.5 MW Diamond Willow Wind Project, located southeast of Baker, Montana began construction in 2007 and consists of 13 General Electric (GE) wind turbines each rated at 1.5 MW. The Diamond Willow Wind Project began commercial operation in February of 2008 and has been serving the integrated system customers since that time.

Montana-Dakota issued a Request for Proposal (RFP) during the spring of 2007 seeking renewable resources that would qualify for the State of Montana Renewable Portfolio Standard (Montana RPS). As part of the RFP, a developer offered the rights to the Diamond Willow Wind Project to Montana-Dakota which was ultimately selected as the winning proposal from the RFP. Montana-Dakota purchased the wind turbines and substation equipment for the project and hired a general contractor to construct the project roads, foundations and erect the wind turbines.

The Diamond Willow Wind Project connects to Montana-Dakota's 57 kV transmission system which runs through the project site. Diamond Willow achieved an annual capacity factor of 39.6 percent in 2009 and a capacity factor of 39.1 percent for the last ten months of 2008.

Montana-Dakota employs two wind technicians who perform all the operation and maintenance for the Diamond Willow project.

The Diamond Willow project was build for $39.4 million which included the cost of the turbines, associated substation, and transmission interconnection facilities.

The 10.5 MW Diamond Willow expansion project began construction in 2009 and consists of 7 GE wind turbines each rated at 1.5 MW. The Diamond Willow expansion project is scheduled to begin commercial operation in June of 2010. The estimated cost of the expansion is $25.4 million which includes turbine equipment, substation facilities, and transmission interconnection costs.

The interconnection substation for Diamond Willow was expanded with a third 10 MVA transformer to accommodate the expansion project.

Q. Please describe the Glen Ullin heat recovery project?

A. The Glen Ullin heat recovery project, named Glen Ullin Station #6, is a 5.3 MW heat recovery generating facility located near Glen Ullin, North Dakota. The Glen Ullin generating station is interconnected with the exhaust stack of the Northern Border Compressor Station #6.

Glen Ullin generating station takes the exhaust of the Northern Border Compressor Station and passes it through a newly installed heat exchanger located in the exhaust path of the turbine for the compressor station. This heat exchanger heats a closed loop oil system which in turn vaporizes and superheats a volatile pentane liquid which in turn drives a turbine and generator. The exhaust of the turbine is sent to an air-cooled condenser where the pentane gas is cooled and condensed back into a liquid.

The Glen Ullin generating station is expected to generate an average of 5.3 MW without the combustion of any additional fuel. The only fuel combusted on-site is used to drive the Northern Border gas

compressor which does not require any additional fuel to support the Montana-Dakota generating equipment. The Glen Ullin Station #6 is considered an intermittent resource because it is only capable of generating if the Northern Border compressor station is operating.

Montana-Dakota has a waste heat purchase and lease agreement with Northern Border. The initial term of the Northern Border agreements is for a 20 year period, with five year extension options available.

Ormat Technologies (Ormat) supplied the equipment and constructed the generating facilities for the Glen Ullin project under an Engineering, Procurement, and Construction Agreement. Ormat is contracted to be the operator for the Glen Ullin generating station for a five year period.

The total cost of Glen Ullin Station #6 was $16.7 million which included the cost of the generating equipment, associated substation, and transmission interconnection facilities. Glen Ullin Station #6 is expected to have an annual capacity factor of 67 percent.

Glen Ullin Station #6 connects to Montana-Dakota's 41.6kV transmission system at the newly constructed Glen Ullin Rodeo Substation.

Q. Please describe the Cedar Hills Wind Project?

A. Cedar Hills Wind is a 19.5 MW wind project, located west of Rhame, North Dakota that Montana-Dakota developed based on experience received during the development and construction of the original Diamond Willow project.

Montana-Dakota looked to develop a new wind project in the vicinity of Diamond Willow for several reasons.

The Diamond Willow project has exhibited that an excellent wind resource exists around the Baker, Montana area. As noted earlier, Diamond Willow's 2009 annual capacity factor was 39.6 percent, and its ten month 2008 capacity factor was 39.1 percent. Also impressive is a wind profile at the Diamond Willow that matches Montana-Dakota's customer load pattern. Most Midwest ISO wind projects generate the majority of their wind output during off-peak hours when customer demand is low.

Siting another wind project near Diamond Willow allows for synergies between the two projects including the sharing of personnel, facilities, tools, and parts.

The Diamond Willow project is located on a Montana-Dakota 57kV transmission circuit which has limited interconnection capability compared to higher voltage transmission facilities. The benefit to utilizing 57kV transmission facilities is the lower cost of interconnection compared to higher voltage facilities. Cedar Hills provides diversity from Diamond Willow by being located on a separate 57kV transmission facility than Diamond Willow.

The Federal Production Tax Credit (PTC) for wind was set to expire in 2009 when Montana-Dakota started looking to develop a new wind project. The PTC provides a tax credit of $21 per MWh of production for a ten year period for qualifying wind generating facilities. Cedar Hills and the

Diamond Willow expansion will both qualify and be eligible for the current PTC. The PTC's will provide a significant savings to Montana-Dakota's customers. The PTC eligibility is currently set to end on December 31, 2012.

Under the Midwest ISO transmission siting and planning practices, available transmission capacity to support new interconnects is allocated on a first come first serve basis. Utilizing the existing capabilities of the transmission system in the Baker and Rhame area, Montana-Dakota is able to efficiently and economically interconnect renewable generation sources onto the existing transmission system before the 2,700 MW of wind projects in the Midwest ISO queue planned to interconnect onto Montana-Dakota's system take up all the available transmission interconnection capability.

The Cedar Hills Project, consisting of 13 GE wind turbines each rated at 1.5 MW, began construction in 2009 and is scheduled to begin commercial operation in June of 2010. The estimated cost of Cedar Hills is $47.4 million which includes turbine equipment, substation facilities, and transmission interconnection costs.

Q. Would you explain how the generation resources you just described will be used to meet the various renewable objectives and requirements applicable in Montana-Dakota service territories?

Yes. The Cedar Hills Wind Project, the Diamond Willow and Diamond Willow expansion projects, along with the Glen Ullin project, will be utilized to help meet the North Dakota and South Dakota Renewable

Objectives and Montana RPS requirements. The North Dakota and South Dakota Renewable Objectives both target that ten percent of customer's energy requirements should come from renewable sources of generation by 2015. The Montana RPS requires five percent of the electricity to serve Montana customers to come from renewable sources beginning in 2008. The Montana RPS requirement increases to ten percent in 2010 and 15 percent in 2015.

Q. **What percentage of Montana-Dakota's energy will come from renewable sources of generation when Cedar Hills and Diamond Willow expansion come online?**

A. 7.3 percent of Montana-Dakota's 2011integrated system customer energy requirements are forecasted to come from the renewable generating sources of Diamond Willow, Cedar Hills, and Glen Ullin Station #6.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-10-___

Direct Testimony

of

Stephanie L. Bosch

Q. Please state your name and business address?

A. My name is Stephanie L. 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 a Regulatory Analyst Supervisor for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Please describe your duties as Regulatory Analyst Supervisor?

A. My primary responsibilities include maintenance of the Company's Customer Information System's rate file and the analysis of revenues for use in rate cases.

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 and have held the positions of Rate Clerk and Regulatory Analyst before assuming my current position in 2007.

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

A. The purpose of my testimony is to discuss the development of the projected sales volumes and revenues as shown in Statement M.

Q. Would you describe the development of the projected sales volumes and revenues?

A. Customers and sales volumes were projected by applying a four year historical average annual increase to the per books customer and volume levels. The revenues were then derived using current rates and substituting the base fuel of $0.01303 per Kwh with the projected fuel and purchased power rate from Statement N.

Q. Would you please explain the derivation of the projected customers?

A. Montana-Dakota derived the projected customers by calculating the average annual increase based on a four year historical period by customer class and applying that increase to the 2009 per books level of customers. The increase was then allocated to the rate schedules within the customer class based on the rate schedule's ratio of customers within the customer class.

Certain customers or rate schedules were reviewed individually and reflect no increase in their customer level for 2010.

Q. Why was a select group of customers reviewed individually?

A. Customers or rate schedules reviewed individually included those currently taking service under a contract as well as customers taking service under Interruptible Large Power Demand Response Rate 38,

Interruptible Large Power Service Rate 39 and General Service Rate 30 where the customer's service has been classified as primary service.

Customers within these rate groups are small enough in class size to allow the customers to be individually reviewed for a change in operations that would necessitate a change in the number of customers for 2010.

Q. Would you please describe the methodology used in developing projected sales volumes?

A. Consistent with the derivation of projected customers, Montana-Dakota calculated a four year average annual increase by customer class to be used in the development of projected Kwh sales. However, prior to increasing the 2009 per books level by the class average, adjustments were necessary to reflect corrections or changes to customers' accounts for certain rate schedules.

Q. Would you explain these adjustments in more detail?

A. Yes, within the General Service Rate 30 class, two customers upgraded their facilities in 2009 resulting in a change in the customers' service to primary service from secondary service. This change in rate classification required the Company to reflect an entire year of sales under the primary service provision of the General Service Rate 30 tariff.

In addition, three customers' accounts were adjusted in late 2009 and early 2010 to reflect the correct rate classification. These corrections

required the Company to reflect an entire year of sales under the customers' current rate classifications.

Montana-Dakota then increased the Kwh sales by the four year class annual average to derive the 2010 projected Kwh using the adjusted 2009 data. The increase in sales volumes was then allocated to the rate schedules within the customer class based on each rate schedule's ratio of sales within the customer class.

The Company then calculated the level of billed KW using the projected Kwh and assumed the same load factor as experienced in 2009.

Q. Were any customers reviewed individually when determining projected sales?

A. Yes. The Company reviewed the historic sales of customers taking service under the primary service provision of General Service Rate 30, Rate 30 contract customers, Interruptible Large Power Demand Response Rate 38 and Interruptible Large Power Service Rate 39. In addition, Company personnel, who have a working relationship with these customers, were also consulted to identify any changes in operations that may occur in 2010. Montana-Dakota then established the projected 2010 sales volumes within this group based on the level of adjusted sales for 2009 with the exception noted below.

The sales volumes for a contract customer were adjusted to reflect the loss of its manufacturing load and its remaining operations in Bismarck. The current contract will cease in July 2010 and its remaining

service will move under the primary service provision of General Service Rate 30.

Q. Did the Company include any adjustment for conservation in its projections?

A. Yes. Montana-Dakota reduced its projected Kwh sales for the General Service Rate 30 Secondary Service rate by the Company's estimated savings for the Commercial Lighting program included in the Company's conservation portfolio in correlation with the American Recovery and Reinvestment Act (ARRA).

Q. How do the projected Kwh sales for 2010 included in this rate case compare to the 2010 sales presented in the Company's Electric Load Forecast included in its Integrated Resource Plan (IRP)?

A. The Company's Electric Load Forecast included in its IRP for North Dakota for 2010 is 1,574,563,000 Kwh. The projected sales included in this rate case as described above are 1,577,853,225 Kwh.

Q. Does that complete your direct testimony?

A. Yes, it does.

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

Before the Public Service Commission of North Dakota

Case No. PU-10-

Direct Testimony
of
Rita A. Mulkern

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

A. Yes. My name is Rita A. Mulkern 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 of 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 North Dakota State University with a Bachelor of Arts degree with majors in Economics and Business Administration and a minor in Statistics. I joined Montana-Dakota in July 1981 as a Regulatory

Statistician, became Cost of Service Supervisor in 1986 and assumed my current position in 1999.

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

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

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.

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

A. The purpose of my testimony is to present the Company's per books cost of service for the twelve months ended December 31, 2009, the projected cost of service for 2010, the calculation of the revenue deficiency and the calculation of the interim request.

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

A. I am sponsoring Statements C through E, Statements G through N, the proposed Rate 58 Fuel and Purchased Power adjustment tariff and Exhibit No. ___(RAM-1).

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

A. Yes, they were.

Q. What were the results of North Dakota electric operations for 2009?

A. Statement L, pages 1 and 2 show the per books income statement and rate base for the total Company and for the North Dakota service area. As shown on page 1, North Dakota electric operations had a return on rate base of 8.701 percent for the twelve months ended December 31, 2009. The details for each line item, i.e. sales revenue, other revenue, etc., are included in the applicable Statement.

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 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 2010 year end test period. As stated by Mr. Goodin, the primary reason for the increase is investment in facilities, including those that will be completed in 2010, and the wind generation expansion projects expected to be completed in the second quarter of 2010. A year end 2010 cost of service will best match the cost and customer levels at the time that the rates will go into

effect. 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 2010?

A. The projected 2010 cost of service is presented in Statement M, which contains all of the schedules supporting the income statement on page 1, and Statement N, which contains all of the schedules supporting the rate base 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 2010 plant and related balances.

Q. Would you describe the projected 2010 revenues?

A. The projected revenues for 2010 are summarized on Statement M, page 2. Ms. Bosch discusses the development of sales revenues in her testimony. Other operating revenues are at the 2009 level, with the exception of miscellaneous service revenues, which were adjusted to include the three year average of KVAR penalty revenue. Penalty revenues were included in the per books sales revenue and were eliminated when sales revenues at current rates were calculated. The adjustment to miscellaneous revenue reflects the movement of penalty revenue from sales revenue to miscellaneous revenue on page 6.

Q. Would you explain the projected wholesales margin and Margin Sharing Adjustment (MSA)?

A. Montana-Dakota is proposing to eliminate the Margin Sharing Adjustment and reflect no wholesale margin revenues in the revenue requirement, as shown on Statement M, page 6. Instead, the Company is proposing to credit 85 percent of all wholesale margins through the Fuel and Purchased Power (FPPA) adjustment. Therefore the projected amount for these items embedded within the calculation of the revenue requirement is zero.

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

A. Yes. The projected operation and maintenance (O&M) expenses are shown in Statement M. Pages 7 through 9 of Statement M summarize the projected O&M expenses, with the details provided on pages 10 through 31.

Fuel and purchased power costs have been restated to the projected fuel and purchased power costs to reflect the inclusion of the Cedar Hills and Diamond Willow wind facilities along with a redispatch to reflect normal outage schedules for the other plants and current market costs for energy. In addition, Montana-Dakota is proposing to add two components to the fuel and purchased power adjustment; demand charges and regional market administrative charges. It is now appropriate to include a component for demand charges because the level of demand charges is subject to change more often, both increasing and decreasing. The market administration costs are those costs associated with the MISO

energy market but recorded in Account 575. These are the Schedule 16 and 17 costs that were previously included in the purchased power Account 555 until FERC required that these cost be recorded in Account 575. Fuel costs associated with the sales for resale are excluded from the projected fuel and purchased power costs as Montana-Dakota is proposing to include sales for resale margin in the FPPA.

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

A. Yes. Labor expense is shown on page 11, with actual labor expense for the twelve months ended December 31, 2009 as the starting point. The labor expense for 2010 was developed by applying the projected percentage increase in total Company labor costs to the 2009 per books North Dakota labor expense. Projected total Company labor costs were based on the labor amounts budgeted for 2010, with bonuses adjusted to reflect a three year average and severance amounts paid in 2009 amortized over three years, and results in a 0.32 percent increase for 2010. The projected labor expense incorporates the savings associated with the integration efforts described by Mr. Goodin.

Benefits expense consists of medical/dental insurance, pension expense, 401K, post-retirement, workers compensation and other benefits. Each of these items, excluding the other benefits, was projected individually for 2010 using the 2010 budgeted amounts and applying the projected change from 2009 to each type of benefit. The Supplemental Income Security Plan (SISP) was eliminated in accordance with past

Commission decisions. The changes in benefits discussed by Mr. Goodin effective in 2010 are incorporated in the projected benefit expense.

Page 13 shows the expenses associated with the 30 MW wind generation expansion at Diamond Willow and Cedar Hills. The expenses include the incremental operation and maintenance expenses for these projects. Likewise, the expenses associated with the Glen Ullin waste heat recovery unit, which commenced commercial operation in July 2009 were annualized to reflect a full year's expense on page 14.

Expenses at the Coyote and Big Stone plants were adjusted to reflect normal operating conditions for 2010. The Coyote plant was out of service for an extended outage from the end of March through early May in 2009.

Material expense reflects an increase to reflect changes at the Lewis & Clark and Diamond Willow generation facilities. Mercury emission control equipment was added to the Lewis & Clark Station in 2009 and the increase annualizes the additional materials required for the equipment. Materials at Diamond Willow increased as the initial warranty on the facilities expired in early 2010 and there was also an increase in the transmission function due to the increased level of activity.

Vehicles and work equipment expense, on page 17 reflects all costs associated with the Company's vehicles and equipment, such as line trucks, including the costs of fuel, insurance, maintenance and depreciation. The projected expenses reflect a decrease due to the

change in the depreciation component. Depreciation is calculated based on the projected plant and the proposed depreciation rates from Statement I. The depreciation expense on these items is not charged to the depreciation account but rather is charged to a clearing account where it is then recorded in O&M expense as the vehicles or work equipment is used.

Company consumption is the expense for electric and natural gas consumption in Company buildings. The slight increase reflects an increase in the electric component to reflect the current rates while the natural gas component is expected to remain the same based on normalized sales levels at the current retail rate, inclusive of a 2010 average cost of gas.

Postage expense is projected to decrease due to the elimination of a prepaid postage purchase in late in 2009 that is applicable to 2010.

Demand side management (DSM) expenses reflect a three year amortization of demand side expenses. These expenses relate primarily to the commercial lighting program and will form the base of the DSM expense level to be used in conjunction with the DSM tracker discussed by Ms. Aberle.

Uncollectible accounts, shown on page 21, are projected based on the five year average of write-offs to revenues, multiplied by the projected sales revenue.

Advertising expense is shown on page 22. Promotional advertising expense has been eliminated and institutional advertising is adjusted to eliminate the expenses not applicable to North Dakota electric operations.

Insurance expense reflects the current insurance expense level for 2010, and is an increase from the 2009 insurance expense level.

Utility discounts are projected to decrease on page 24. Montana-Dakota eliminated the employee discount for active employees effective February 1, 2010 as part of its integration efforts. Expenses will not be eliminated entirely as the discount will continue to be provided as a retiree benefit to employees that retired prior to January 1, 2010.

Industry dues reflect the projected level of industry dues and eliminates those dues not specifically applicable to North Dakota electric operations.

Regulatory commission expense reflects the expenses expected to be incurred in this case, amortized over a three-year period, and an ongoing level of regulatory commission expense.

The projected O&M expense on page 28 is for the O&M expenses not specifically identifiable or calculated as described above, adjusted for the effects of inflation. A 2.11 percent inflation factor, based on the increase in the consumer price index for 2007-2009, was applied to the expenses not specifically adjusted. Montana-Dakota adjusted approximately 90 percent of expenses individually and the adjustment for inflation is applicable to approximately 10 percent of O&M.

Q. Would you describe the calculation of depreciation expense?

A. Yes. Projected depreciation expense is shown in Statement M, pages 32 through 35. The calculation of depreciation expense and the associated accumulated reserve for depreciation is shown on page 33 and 34 and is the annualized depreciation expense on projected plant, calculated using the projected plant in service, excluding the Diamond Willow and Cedar Hills additions, and the proposed depreciation rates. The proposed depreciation rates are from a depreciation study by AUS Consultants, Inc., using plant as of December 31, 2008, with the depreciation rate summary shown on Statement I, pages 2 through 8. The steam production depreciation rates include interim net negative sales amounts, which the Company has not previously requested. The depreciation expense on the Diamond Willow and Cedars Hills additions is on page 35.

Q. Would you describe the calculation of taxes other than income?

A. Yes. Taxes other than income are shown on pages 36 through 41 of Statement M. Ad valorem taxes were restated using projected plant in service and applying the effective tax rates based on the 2009 ratio of ad valorem taxes to plant. The ad valorem taxes on Cedar Hills and the new increment of Diamond Willow were calculated separately on page 39.

Projected payroll taxes were based on the ratio of payroll taxes to labor expense for 2009 and applied to projected labor expense to determine the projected payroll taxes.

Generation taxes are made up of the North Dakota coal conversion tax and the Montana energy taxes. These taxes were restated to reflect the projected generation of energy.

All other taxes other than income taxes remained at the 2009 level.

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

A. The projected income tax calculation for North Dakota electric operations is shown on pages 42 through 44. Interest is deductible for tax purposes. Interest expense is calculated on the projected rate base using the debt ratio and weighted cost of debt from Statement F on 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.

The production tax credit, shown on page 44, is applicable to generation from wind facilities and the projected amount for 2010 reflects the additional wind generation from the Diamond Willow and Cedar Hills generation.

Q. Would you please describe the development of projected rate base?

A. Yes. The rate base is summarized on Statement N, page 1 and shows the 2009 actual and projected 2010 rate base for North Dakota electric operations. Pages 2 through 23 are the supporting components of the projected rate base.

Pages 2 through 12 show the projected plant in service for 2010. The projected plant was developed by adding the capital budget items for 2010 to the 2009 plant in service balances. Retirements, based on a three-year average of retirements by function, were deducted. The complete list of plant additions are included in pages 4 through 10. The addition of 10.5 MW of wind at the Diamond Willow wind facility and 19.5 MW Cedar Hills facility are shown on page 11. The reallocation of the 19.5 MW Diamond Willow generation that commenced operation in 2008 is shown on page 12. Montana-Dakota has historically allocated all generation facilities to the jurisdictions on the twelve month integrated system peak demand. The wind, while providing capacity, is more reflective of an energy facility than meeting peak demand and Montana-Dakota is now allocating wind generation to the jurisdictions on a combined demand and energy factor made up of 20 percent of the twelve month system peak demand factor and 80 percent of the interconnected system kwh sales factor. Both the plant and accumulated reserve were reallocated to North Dakota electric operations.

The accumulated reserve for depreciation is summarized on page 13 and was calculated using the reserve balances at December 31, 2009, adding the calculated depreciation expense and deducting retirements based on a three-year average of retirements. The 2010 balances were then calculated and are shown on Statement M, pages 33 and 34.

Q. How were the working capital items derived?

A. The projected working capital items are shown on pages 14 through 21 of Statement N. Materials and supplies were restated to a thirteen month average balance on page 15.

Fuel stores are restated to current cost levels and a thirteen month average balance on page 16.

Prepayments, made up of prepaid insurance, as shown on page 17, are also restated to a thirteen-month average balance. Projected 2010 balances are based on the actual balances as of December 31, 2009 and projected monthly levels based on the current insurance expense levels for 2010.

The unamortized loss on reacquired debt is shown on page 18. When Montana-Dakota reacquires debt in order to reduce its debt costs, the unamortized loss is then amortized over the remaining life of the new issuance. Customers benefit through the net lower cost of debt and it is proper to include the cost of achieving the savings through the inclusion of the unamortized balance of the loss on debt in rate base.

The deferred generation costs are shown on page 19. The deferred generation costs are made up of the costs incurred by Montana-Dakota in its efforts to acquire generation resources in the Lignite Vision 21 project, the Milton R. Young III project and the Big Stone II project. The recovery of the Big Stone II project is also currently the subject of Case No. PU-09-733 and, if resolved separately will be removed from this

case. The total deferred generation costs are amortized over ten years, with the unamortized amount in rate base.

Page 20 is the amortization of the costs of decommissioning retired power plants. Montana-Dakota recovered the costs of decommissioning the retired plants in a previous rate case based on an estimate of costs. Upon completion of the decommissioning, the actual costs were less than the estimate and Montana-Dakota is returning that amount to customers over a ten year period, with the unamortized amount a credit to the rate base.

Customer Advances for construction are restated to a thirteen month balance using actual amounts as of January 31, 2010.

The accumulated deferred income tax balances on page 22 were derived based on the projected activity for 2010.

The accumulated investment tax credit balances are projected to be fully amortized in 2010.

Q. What does Statement L, page 3 show?

A. Statement L, page 3, shows the calculation of the revenue deficiency of $15,394,000 based on the projected 2010 operating income and rate base and using the overall rate of return of 9.051% from Statement F, page 1 and supported by Dr. Gaske and Mr. Senger.

Q. What changes are you proposing to the Rate 58 Fuel Cost Adjustment (FCA)?

A. Montana-Dakota is proposing to incorporate several changes in the fuel cost adjustment and to rename the tariff the Fuel and Purchased Power (FPPA) adjustment. The first, as discussed earlier, is to eliminate the margin sharing adjustment and instead, credit 85 percent of all wholesale margins as a credit in the FPPA. The benefits to this method are that all margin is subject to the sharing, the margin will be passed back to customers through the monthly adjustment and therefore reflected more timely, eliminates the need for the MSA while still providing an incentive to the Company to run its plants efficiently in order to make sales into the market. As discussed by Mr. Neigum, the market for sales for resale has changed significantly since the MSA was adopted in Docket No. PU-399-03-296 and the proposed method is a more efficient means of providing the credits to customers. However, the outstanding balance in the MSA will still require recovery and the Company is proposing to place the unamortized balance at the time final rates become effective into the FPPA deferred account.

The Company is also proposing to implement separate primary service and secondary service classes in the FPPA. There are differences in the customer classes that warrant separating the FPPA into customer classes. Montana-Dakota is proposing to establish a separate base cost of fuel and purchased power under two classifications: (1) customers taking service at the primary level, defined as customers metered at primary voltages of 2,400 volts or greater that own their own

transformers, related equipment, and distribution facilities downstream of the meter (available under Rates 30, 31, 32, 38, 41, 48 and 52), and (2) secondary customers taking service at the secondary level, which represents all other customers. This differentiation into the two classifications described above provides the means to track changes in the cost of fuel and power supply consistent with the base fuel established through the allocation process in the class cost of service study and accounts for differences in losses and demand allocations. The allocation to the proposed FPPA classes is based on the allocations contained in the embedded cost of service study and is supported by Ms. Aberle.

Finally, Montana-Dakota is proposing to include two new items in the FPPA, Market Administration charges and demand charges. The Market Administration charges are the MISO Schedule 16 and 17 charges associated with the MISO energy market and were previously recorded in Account 555 purchased power and therefore included in the FCA. FERC issued an Order requiring that those costs be recorded in Account 575, which was not included in the FCA. These costs relate to the energy market are should be recovered in the same manner as other energy costs. Correspondingly, the Market Administration costs have been eliminated from O&M expense on Statement M, page 31.

Demand charges have previously not been included in the fuel cost adjustment as they were traditionally long term agreements, such as the 20 year AVS II contract that expired in 2006. Today, demand, or capacity

agreements are short term in nature and it is more appropriate to include these in the FPPA instead of the cost of service so that changes, both increases and decreases, can be passed on to customers in a timely manner without filing a general rate case.

Exhibit No. ___(RAM-1), page 1 illustrates the calculation of the base cost of fuel and purchased power while page 2 is a sample calculation of the proposed FPPA including the credit for wholesale sales margin at 85 percent.

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

A. Yes, it is. As stated by Mr. Goodin, Montana-Dakota is seeking interim rate relief in this case pursuant to North Dakota §49-09-06.

Q. How was the interim revenue requirement increase derived?

A. The Interim Revenue Requirement, page 1, shows the calculation of the revenue deficiency of $7,617,000 based on the 2010 projected cost of service and adjusted for items previously not allowed or not reviewed by the Commission.

The interim revenue requirement excludes the proposed changes to wholesale margins and the MSA, a major transmission plant investment that will not be complete until the end of 2010, the interim net negative salvage on steam production plant and the deferred generation balances and amortization. The revenue requirement calculation uses the projected 2010 capital structure and capital costs including the authorized return on equity, which is the return on equity last authorized by this

Commission in Case No. PU-399-03-296, and is the same as the proposed return on equity.

Q. Does that complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
FUEL AND PURCHASED POWER ADJUSTMENT - NORTH DAKOTA
PROJECTED 2010
BASE COST OF FUEL AND PURCHASED POWER
(000s)

	Total 1/	Allocation to 2/ North Dakota	Allocation to 3/ Primary	Allocation to 3/ Secondary
Fuel & Purchased Power Costs				
Account 501 and 547	$46,122	$29,928	$3,404	$26,524
Account 555 Energy	5,816	3,774	429	3,345
Account 555 Demand	2,075	1,438	100	1,338
Account 575 Market Admin.	508	330	38	292
Total Fuel & Purchased Power	$54,521	$35,470	$3,971	$31,499
Fuel Costs - Wholesale sales	4,095	2,657	302	2,355
Net System Costs	$50,426	$32,813	$3,669	$29,144
Mwh Retail Sales		1,577,853	181,271	1,396,582
Base Cost of Fuel - per Kwh		$0.02080	$0.02024	$0.02087

1/ Statement M, page 10.
2/ Energy allocated on Alocation Factor No. 16, Interconnected Kwh sales and demand is allocated on Allocation Factor No. 15, Integrated System peak demand.
3/ Energy is allocated on Kwh sales at generation and demand is allocated on class Allocation Factor No. 2, Average and Excess Demand.

MONTANA-DAKOTA UTILITIES CO.
FUEL AND PURCHASED POWER ADJUSTMENT - NORTH DAKOTA
PROJECTED 2010
PROPOSED ADJUSTMENT
(000s)

	Total 1/	Allocation to 2/ North Dakota	Allocation to 3/ Primary	Allocation to 3/ Secondary
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Fuel Costs - Wholesale sales	4,095	2,657	302	2,355
Net System Costs	$50,426	$32,813	$3,669	$29,144
Wholesale sales Margin 4/	(513)	(392)	(45)	(347)
Total Costs - net of margin	$49,913	$32,421	$3,624	$28,797
Mwh Retail Sales		1,577,853	181,271	1,396,582
Cost Per Kwh		$0.02055	$0.01999	$0.02062
Base Cost of Fuel 5/			0.02024	0.02087
FPPA			($0.00025)	($0.00025)

1/ Statement M, page 10.
2/ Energy allocated on Alocation Factor No. 16, Interconnected Kwh sales and demand is allocated on Allocation Factor No. 15, Integrated System peak demand.
3/ Energy is allocated on Kwh sales at generation and demand is allocated on class Allocation Factor No. 2, Average and Excess Demand.
4/ 85 percent of 2009 wholesale margin .
5/ Page 1.

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

Before the Public Service Commission of North Dakota

Case No. PU-10____

Direct Testimony
of
Tamie A. Aberle

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

A. Yes. My name is Tamie A. Aberle, 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 Pricing & Tariff Manager in the Regulatory Affairs Department of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. What are your responsibilities as the Pricing & Tariff Manager?

A. My responsibilities include the preparation of rate design and miscellaneous tariff revision filings to ensure that the applicable revenue requirements are properly recovered from various customer classes via applicable rate forms. I also administer utility tariffs and rules and regulations effective in each of the jurisdictions in which Montana-Dakota provides utility service.

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

A. I graduated from Moorhead State University, Moorhead, Minnesota in 1982 with a Bachelor of Science degree in Accounting. I began my career with Montana-Dakota in 1983 in the Regulatory Affairs Department, I was promoted to Rate Administration Supervisor in 1990 and achieved

my present position in May 1999.

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. 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 requirement, as identified by Ms. Mulkern in her direct testimony, on each of the Company's electric rates, including how the distribution of the revenue requirement was made among the various customer classes served. In addition, my testimony will discuss the extent to which Montana-Dakota is proposing changes in rate design and proposed tariff changes.

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

A. I am sponsoring Statement O, Statement P and Exhibit No. ___ (TAA-1) through Exhibit No.___(TAA-2). I also sponsor the proposed rate schedules provided in Appendix B to the Application, other than the Fuel and Purchased Power Adjustment Rate 58 schedule sponsored by Ms. Mulkern.

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

A. The proposed rates will produce additional revenues of $15,396,303 or an increase of 13.9% annually based on projected 2010 electric consumption. Exhibit No. ____ (TAA-1) represents summaries by

rate classification of the proposed final revenue increase. The exhibit shows the rate class and the revenues calculated under the present and proposed rates. The amount and percentage increase is also shown for the proposed revenue increase.

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

A. Yes. Statement O provides a report entitled "Cost of Service by Component." This report shows the total dollars and unit cost required under each rate if the overall requested rate of return of 9.091% is to be earned for the demand, energy and customer cost components of each rate schedule. The rate of return before allocation of the requested increase is also shown on Statement O. As an example, the resulting rate of return on the rate base allocated to residential customers under Residential Service Rate 10 is 3.386% and a revenue increase of approximately $12,693,000 would be necessary to bring the residential rate of return to the overall average return. Statement O, page 1 also indicates that the customer related component associated with providing service to the residential class is $16.40 per month with the demand and energy components comprising the remaining requirement at $0.075 per Kwh. This same information is shown for each rate schedule on pages 2 through 15 of Statement O.

A summary of the rate base and income statement items reflecting the allocation of the projected 2010 cost of service supported by Ms. Mulkern in her testimony is provided on page 16 of Statement O.

Statement O, Schedule O-1 provides a detailed report of the projected rate base and income statement as allocated to each rate

schedule. The allocation factor applied to the total North Dakota electric amount is shown on each line item.

Statement O, Schedule O-2 provides a list of the allocation factors used to allocate the total North Dakota electric amount to each class and cost component as referenced in Schedule O-1.

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

A. The overall North Dakota electric rate of return based on the projected 2010 test period presented by Ms. Mulkern of 5.809%. The returns by customer class are as shown below:

Customer Class	ROR
Residential Service	3.386%
Small General Service	7.380%
Irrigation Service	-6.061%
General Service - Primary	5.656%
General Service – Secondary	8.602%
Time of Day Large General Service	7.621%
Space Heating Service	7.983%
Small Municipal Service	2.293%
Municipal Lighting Service – Primary	13.023%
Municipal Lighting Service – Secondary	12.394%
Municipal Pumping Service - Primary	1.276%
Municipal Pumping Service - Secondary	2.982%
Outdoor Lighting	13.744%
Interruptible Power Service	5.647%
Interruptible Demand Response Service	9.662%

Q. How did you determine what costs should be assigned 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 Kw demand

imposed by the customer, energy-related costs vary with the energy or Kwh the customer uses 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 on Statement O, Schedule O-2.

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 the rate base schedule starting on Statement O, Schedule O-1, page 1. The plant allocation serves as the basis for allocating many of the other rate base items. The investment in production related plant items was allocated on an average and excess demand (AED) allocator to account for the contribution of each class based on a combination of the classes' average demand and non-coincident peak demands. The AED factor is comprised of the sum of the average demand of each class and the difference between the total system peak demand and the average demand as allocated to each class based on the non-coincident demand in excess of the average demand. The production investment related to the Company's wind facilities was allocated on a factor based 80% on the energy allocation factor (Factor No.1) and 20% on the AED allocator to reflect the fact the wind facilities are primarily an energy resource. The

investment in transmission plant related items was allocated on the AED factor.

Turning now to the distribution plant investment; each distribution plant account is analyzed and allocated based on the cause for the investment. Station equipment and the associated land and land rights are allocated on the non-coincident peak demand of each class, representing the maximum demand on the system. The next set of plant items - Poles, Towers & Fixtures; Overhead Conductors & Devices; and Underground Conduit & Devices were classified as customer and demand related based on an analysis of the minimum and normal system design for a typical distribution system, with the minimum system representing the percentage of the plant accounts assigned to the customer component, and the remainder classified as demand related. Based on this analysis, the minimum investment necessary to connect a customer was determined to be 83% of the total required investment. The amounts classified as customer related were then allocated to each rate class based on the number of customers served in each rate class, or Factor No. 7. The dollar value of the Poles, Towers & Fixtures; Overhead Conductors & Devices; and Underground Conduit & Devices classified as demand related (17% of the total) was allocated to each rate class based on the maximum demand of each rate class (non-coincident peak Factor No. 4). The investment in Line Transformers was also classified as customer and demand related. The percentage assigned to the customer

component was determined based on the minimum intercept method which seeks to identify the portion of the transformer investment associated with a hypothetical no-load condition. Based on an analysis of the type and size of transformers, representing the minimum equipment necessary to provide service to secondary system customers, the zero intercept was determined to be $1,446. Applying this amount to the number of transformers resulted in a customer component of 76% with the remaining 24% classified as demand related. The classified costs were allocated on weighted customer transformers (Factor 11) and the non-coincident secondary demand factor (Factor 5) accordingly.

The four remaining distribution accounts; Services, Meters, Installation on Customer Premises and Street Light & Signal System are all related solely to a customer connection and were classified as customer related. Services were allocated to the rate classes based on a factor representing services weighted by customer class derived by comparing the installed cost per service for each rate class to the cost necessary to serve Residential service customers. The weights were then applied to the number of customers in each rate class. The same process was used to fashion an allocation based on weighted meter costs (Factor No. 8) for allocating the embedded investment in meters. The investment in Installation on Customer Premises was directly assigned to Outdoor Lighting and the investment in Street Light & Signal Systems was directly assigned to Municipal Lighting. The allocation of the remainder of the rate

base items is self explanatory with the allocation factor noted for each line item.

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

A. Yes. The allocation of the income statement items starts on Statement O, Schedule O-1, page 3 with the allocation of revenues. As shown, revenues are primarily directly assigned based on the revenues produced under each rate schedule. The revenues identified as Contracts represent the revenues produced under two specific electric service contracts. The contract revenues were allocated to each class based on demand, energy and customer allocators to offset costs associated with providing service to the two contract customers that were allocated to all other classes. The revenues to be collected under the contracts are established pursuant to the terms of the service agreements so costs were not allocated to a separate class for contracts and the billing units for customers under the contracts were not included as part of the allocation factors. The Other Revenues that cannot be directly assigned to a particular rate class are allocated based on the source of the revenue item. Each item is shown along with the allocation factor applied.

Operation and maintenance expenses consisting of fuel, purchased power costs, transmission, distribution and administrative and general expenses are shown starting at Schedule O-1, page 5. The production expenses are classified as demand and energy related with the fuel,

purchased power and variable production expenses classified as energy and allocated based on the energy requirements of each class. The other production expenses and purchased capacity costs are classified as demand costs and allocated on the same demand allocator used to allocate production plant costs. Transmission operation and maintenance costs are also classified as demand related and allocated on the AED demand allocator (Factor No. 2). Customer Accounts Expense and Customer Service and Information Expenses were allocated on a weighted customer factor (Factor No. 12) based on the estimated cost of meter reading and customer billing for each class relative to the residential weighting set equal to 1.0. 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. For what purpose has the embedded class cost of service study been used?

A. The study results have been used for the purpose of analyzing the various components comprising the total rate applicable to each customer class. In addition to providing the rate of return provided by each customer class, the class study provides the basis for the customer related costs to be collected under the Basic Service Charge component

of each rate schedule and the demand related costs to be collected under the Demand Charge component of those rate schedules where demand is metered and measured for billing purposes.

Q. Would you please explain how the proposed rate increase was apportioned among the customer classes?

A. Yes. In designing the proposed rates to reflect the additional revenue requirement I first considered the results of the embedded cost study, which provided the increase required from each class to produce the overall rate of return of 9.091% as shown on the Cost by Component report provided in Statement O, pages 1 through 15 and as summarized on Statement P, page 2. While moving each rate class to the overall rate of return is a desired outcome in meeting the widely held objective of the fair return standard, the magnitude of the increases required for the residential service, irrigation service, small municipal service and municipal pumping service customers was too severe when considering the increases would be two or more times greater than the overall increase of 13.9%. It was determined that mitigation was necessary in order to balance the fair return standard with the recognition of customer impacts. The result was an equal allocation of the non-fuel related costs to each rate schedule. As Ms. Mulkern described, the Company is proposing to separate the base fuel and purchased power component between primary and secondary service which resulted in a reallocation of fuel related costs among the various primary and secondary service

schedules. The allocation of the revenue increase is shown on Statement P, page 3.

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

A. As shown on Exhibit No. ___(TAA-1) and the table below, the resulting proposed percentage increase to each of the classes is as follows:

	Revenue Increase	
Customer Class	**$**	**%**
Residential Service	$6,469,473	14.1%
Small General Service	1,275,437	14.8%
General Service	7,172,206	13.6%
Municipal Lighting	195,437	13.8%
Municipal Pumping	211,142	12.4%
Outdoor Lighting Service	72,608	14.7%
Total North Dakota Electric	$15,396,303	13.9%

Q. **Once you allocated the increase in revenue to each of the customer classes, how did you then determine each of the components of the proposed rates?**

A. The embedded cost study was used as a guide in determining the level of the cost components for each rate schedule. Changes in the Base Rate and Demand Charge components have been proposed for each applicable rate schedule in order to continue to move these charges closer to cost.

Q. Would you please describe the changes you are proposing for each rate schedule?

A. Yes. Starting with Residential Service Rate 10, the base rate component (which has been renamed Basic Service Charge) was increased to $0.35 per day or $10.64 per month, an increase of $5.14 per month from the present rate. This proposed charge is well below the customer component supported in the embedded class study of $16.40 as shown on Statement O, page 1. The proposed charge provides a balance between reflecting true cost and recognizing customer impacts. The Basic Service Charge is proposed to be collected on a daily basis in order to avoid prorating the monthly charge when customers are in service less than 30 days, on average, or when a billing period extends beyond a 30 day average. The Company's natural gas service Basic Service Charge has been assessed on a daily basis since 2002 and has been well accepted by customers. The energy charges for the residential schedule were determined by reducing the total revenue responsibility for the class by the revenues to be collected under the proposed Basic Service Charge and the projected Base Fuel and Purchased Power component for secondary service. The revenues remaining to be collected were divided by the projected Rate 10 sales to determine the cost per Kwh required to be collected through the energy component. The calculations just described are provided for each rate schedule on pages 4-21 of Statement P.

The process described above for the calculation of the proposed Residential Rate 10 schedule was used to determine the rate components for each of the other rate schedules, that is, the first step was to establish the Basic Service Charge by considering the customer costs identified in the embedded cost of service study and the Demand Charge based on the demand costs identified in the embedded class cost of service study for those rate schedules where demand metering is warranted. The second step was to deduct the revenues to be recovered under the Basic Service Charge, Demand Charge and Base Fuel and Purchased Power components for each rate schedule. The Energy Charge component was then determined by dividing the revenues remaining to be collected by the projected sales under the applicable rate schedule.

A summary of the rate charges for each schedule provided on page 3 of Statement P. Exhibit No.___(TAA-2) provides the distribution of customers falling into the various annual bill impact ranges by dollar and percentage change from current bills for the residential and small general service classes.

Q. Would you please describe the new rate offering entitled Optional Residential Electric Thermal Energy Storage Rate 13?

A. Yes. As noted in the title this is an optional rate available to residential service customers with electric space heating requirements choosing to utilize a thermal storage system that uses electricity during the off-peak hours of 11:00 p.m. to 7:00 a.m. and stores that energy for use

during the remaining hours of the day. This technology provides for an overall decrease in energy use of approximately 40% and the use of that energy during the time when the electric system is at its lowest use and lowest cost to serve. The rate has been established with a reduction of $.005 per Kwh from the rate applicable under Residential Service Rate 10 for use over 750 Kwh per month during the months of October through May. This rate, along with potential funds for rebates to offset upfront equipment costs, through the North Dakota Utility Rebate Program funded by The American Recovery and Reinvestment Act, will provide a cost effective conservation alternative available to residential customers.

Q. Ms. Aberle, would you please explain the Adjustment Clauses referenced on each of the proposed rate schedules?

A. Yes. The electric service rate schedules each call for the application of four separate adjustment mechanisms. The Adjustment Clauses include:

- **Load Management Tracking Adjustment (LMTA)** defined as Rate Schedule 54 is proposed in order to establish the framework for cost recovery of demand-side management and conservation program as approved by the Commission. This adjustment mechanism was originally submitted on July 1, 2009 in compliance with the Commission's Order issued in the Big Stone II prudency matter (Case No. PU-06-482) in which a Commission decision has not yet been rendered. A cost adjustment to be applicable under

the mechanism is not being proposed at this time.

- **Renewable Resource Cost Recovery Rider (RRC)** defined as Rate Schedule 55, is proposed to recover the costs associated with the Company's investment in renewable resources as authorized by the Commission. This tariff was first submitted on May 29, 2009 in a filing docketed by the Commission as Case No. PU-09-225. The Company subsequently withdrew its request in Case No. PU-09-225 on November 9, 2009, noting the tariff would be filed as part of the next general rate case. The renewable resources included as part of the projected cost of service in this rate case would not be part of the RRC. The tariff is proposed herein to provide for the recovery of any future investments that are subsequently approved by the Commission outside of a general rate case.
- **Transmission Cost Recovery Rider (TCRR)** defined as Rate Schedule 56 is proposed to recover transmission investments and federally regulated transmission related costs charged to the Company that are not part of rates established in this rate case as provided for by the North Dakota Century Code at Section 49-05-04.3. As with the LMTA and the RRC, the request here is to establish the mechanisms for future use in recovering applicable expenditures and an adjustment is not proposed to be charged at this time.

- **Fuel and Purchased Power Adjustment (FPPA)** defined as Rate 58 is the mechanism currently established to recover the cost of fuel and purchased power. The adjustment mechanism has been revised as described by Ms. Mulkern to include the recovery of purchased power demand costs and to provide a means of sharing wholesale sales margins with customers which allows the Company to delete the current Margin Sharing Adjustment Rate Schedule Rate 57.

Q. Would you please briefly describe other changes made to the Company's electric tariff?

A. Yes. Following is a description of other changes the Company is proposing to make to its electric tariff as clearly identified in the legislative copy of the tariffs provided in Appendix B of the Application:

- As noted above, the Base Rate has been renamed Basic Service Charge and is stated as a daily charge for service under Rate Schedules 10, 13, 16, 20, 25, 26 and 40.
- The determination of the rate applicable to general service customers has been revised to remove the criteria associated with service entrances as this has been found to be unnecessary given the usage limits established in the last rate case.
- A new schedule entitled General Provisions Rate 100 is

proposed to provide a single point of reference for customer service related conditions and charges currently stated separated on the following schedules:

- Rule Governing Discontinuance of Service for Nonpayment of Bill -- Rate 101,
- Residential Electric Service for Permanent Employees Rate -- Rate 102,
- Consumer Deposits – Rate 106,
- Notice to Discontinue Electric Service – Rate 107,
- Reconnection Fee for Seasonal Customers – Rate 108,
- Late Payment Charge/Returned Check Charge – Rate 109,
- Method for Computing Initial or Final Bills for Electric Service for Less Than a Full Monthly Billing Period – Rate 113,
- Rules for Application of Service – Rate 114,
- Tax Clause – Rate 130,
- Selective Plan for Watthour Meters – Rate 131 and
- Rules and Policies for Implementing Master Metering Restriction – Rae 133.

- Minor changes which are self explanatory have been made to several rate schedules. These changes are clearly denoted on the tariff sheets reflecting the legislative format.

Q. Have changes been made to the provisions that you just described as moving to the new General Provisions Rate 100 schedule?

A. I am proposing to increase the returned check charge to $15.00 per occurrence to more closely track the cost of processing a return check charge. The other changes proposed were made to provide consistency with the Company's Natural Gas General Provisions Rate 100 where applicable and to provide a tariff reference to Commission Rules where appropriate, such as describing the Commission requirements relating to billing adjustments. The new Rate 100 will provide customers and employees with a ready reference to the customer service rules.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Allocation of Revenues
Projected 2010

	Projected 2010 Billing Determinants and Revenues								Revenue Increase	
Customer Class	**Customers**	**Kwh**	**KW**	**Base Rate**	**Energy**	**Demand**	**Fuel Rev**	**Total**	**$**	**%**
Residential Service	62,489	621,493,423		$4,154,798	$28,719,034	$0	$12,927,064	$45,800,896	$6,469,473	14.1%
Small General Service	8,942	102,645,326	16,689.6	2,201,261	4,223,313	54,143	2,135,023	8,613,740	1,275,437	14.8%
General Service	3,053	797,132,225	2,378,794.5	1,382,808	15,885,892	19,080,562	16,554,501	52,903,763	7,172,206	13.6%
Municipal Lighting	480	20,178,381			993,511		419,710	1,413,221	195,437	13.8%
Municipal Pumping	306	30,362,442	114,276.6	38,153	646,642	382,794	631,539	1,699,128	211,142	12.4%
Outdoor Lighting Service	488	6,041,428			368,824		125,662	494,486	72,608	14.7%
Total North Dakota Electric	**75,758**	**1,577,853,225**	**$2,509,761**	**$7,777,020**	**$50,837,216**	**$19,517,499**	**$32,793,499**	**$110,925,234**	**$15,396,303**	**13.9%**

Case No._____
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MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA
Bill Comparison Annual Effects
Residential Rate 10

Overall Annual Effect in Dollars				Overall Annual Effect by Percent			
Range	Customers	Total Customers	Average Use	Range	Customers	Total Customers	Average Use
< than -$100	0	0	0	< than -25%	0	0	0
-$100 to -$51	0	0	0	-25% to 0%	0	0	0
-$50 to $0	0	0	0	1% to 5%	0	0	0
$1 to $25	11,488	11,488	618	6% to 10%	5,885	5,885	14,130
$26 to $50	8,526	20,014	2,460	11% to 25%	56,997	62,882	7,408
$51 to $75	22,195	42,209	4,051	26% to 50%	9,943	72,825	1,040
$76 to $100	21,879	64,088	9,509	51% to 75%	3,287	76,112	182
$101 to $200	12,386	76,474	18,007	76% to 100%	1,912	78,024	29
$201 to $300	1,310	77,784	36,157	> than 100%	0	78,024	0
$301 to $400	175	77,959	53,281				
$401 to $500	23	77,982	74,856				
$501 to $600	20	78,002	97,962				
$601 to $700	8	78,010	107,473				
$701 to $800	4	78,014	136,699				
$801 to $900	1	78,015	150,280				
> than $900	9	78,024	211,418				

Current Rate 10

Base Rate	$5.50	per month
Energy Charge		
Summer	$0.05527	per Kwh
Winter		
First 750	0.05527	
Over 750	0.02128	
Fuel Charge	0.02179	

Proposed Rate 10

Base Rate	$0.35	per day
Energy Charge		
Summer	$0.05830	per Kwh
Winter		
First 750	0.05830	
Over 750	0.02830	
Fuel Charge	0.02087	

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA
Bill Comparison Annual Effects
Small General Rate 20

Overall Annual Effect in Dollars				Overall Annual Effect by Percent			
Range	Customers	Total Customers	Average Use	Range	Customers	Total Customers	Average Use
< than -$100	0	0	0	< than -25%	0	0	0
-$100 to -$51	0	0	0	-25% to 0%	0	0	0
-$50 to $0	0	0	0	1% to 5%	0	0	0
$1 to $25	2,041	2,041	357	6% to 10%	2,369	2,369	844
$26 to $50	1,532	3,573	1,966	11% to 25%	7,244	9,613	13,984
$51 to $75	1,184	4,757	3,955	26% to 50%	0	9,613	0
$76 to $100	919	5,676	6,142	51% to 75%	0	9,613	0
$101 to $200	2,230	7,906	11,814	76% to 100%	0	9,613	0
$201 to $300	1,000	8,906	23,648	> than 100%	0	9,613	0
$301 to $400	455	9,361	35,290				
$401 to $500	150	9,511	47,195				
$501 to $600	48	9,559	59,204				
$601 to $700	23	9,582	70,017				
$701 to $800	12	9,594	84,854				
$801 to $900	7	9,601	94,034				
> than $900	12	9,613	148,708				

Current Rate 20		
Base Rate	$20.00	per month
Energy Charge		
Summer	$0.05486	per Kwh
Winter		
First 750	0.05486	
Over 750	0.02128	
Fuel Charge	0.02179	

Proposed Rate 20		
Base Rate	$0.70	per day
Energy Charge		
Summer	$0.06849	per Kwh
Winter		
First 750	0.06849	
Over 750	0.02830	
Fuel Charge	0.02087	