STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.,
A Division of MDU Resources Group, Inc.
2016 Electric Rate Increase
Application

Case No. PU-16-666

AFFIDAVIT OF SERVICE BY ELECTRONIC MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Geralyn R. Schmaltz deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **24th** day of **February, 2017,** she electronically mailed to **6** recipients, an electronic copy of:

- **Direct Testimony of Sara Cardwell**
- **Direct Testimony and Exhibits of Richard A. Polich, P. E.**
- **Direct Testimony and Exhibits of Jacob M. Thomas, P. E.**

The electronic mails were addressed as follows:

Karl Lieipitz,
Senior Attorney
MDU Resources Group, Inc.
Karl.Liepitz@mduresources.com

Tamie Aberle
Director of Regulatory Affairs
Montana-Dakota Utilities, Co.
Tamie.Aberle@mdu.com

John B. Coffman
Attorney for Intervenor AARP
John B. Coffman, LLC
john@johncoffman.net

Paul Sanderson
Attorney for MDU Resources Group, Inc.
Evenson Sanderson PC
psanderson@esattorneys.com

David A. Tschider
Attorney for Intervenor AARP
Tschider & Smith
dtschider@tschider-smithlaw.com

Patrick Ward
Administrative Law Judge
pward@zkslaw.com

64 PU-16-666 Filed 02/24/2017 Pages: 135
Affidavit of Service, E-mail - Prefiled Testimony of R. Polich, J. Thomas, and S. Cardwell
Public Service Commission

Each email address is the respective addressee's last reasonably ascertainable electronic mailing address.

Subscribed and sworn to before me
this **24th** day of **February, 2017.**

Shelly A Bausk
Notary Public

SEAL

SHELLY A BAUSKE
Notary Public
State of North Dakota
My Commission Expires Sep 01, 2022

Schmaltz, Geralyn R.

From:	Schmaltz, Geralyn R.
Sent:	Friday, February 24, 2017 4:26 PM
To:	'Karl.Liepitz@mduresources.com'; 'psanderson@esattorneys.com'; Tamie Aberle; 'dtschider@tschider-smithlaw.com'; 'john@johncoffman.net'; Patrick Ward (pward@zkslaw.com)
Subject:	PSC Case No. PU-16-666 Affidavit of Service with Testimony & Exhibits
Attachments:	PSC Case No. PU-16-666 Affidavit of Service.pdf; Testimony-Jacob Thomas.pdf; Testimony-Richard Polich.pdf; Testimony-Sara Cardwell.pdf

Good Afternoon!

Attached please find the Affidavit of Service by Electronic Mail, Direct Testimony of Sara Cardwell, Direct Testimony & Exhibits of Richard A. Polich, and Direct Testimony & Exhibits of Jacob M. Thomas for PSC Case No. PU-16-666.

A hard copy of these testimonies will follow in the mail.

Have a good weekend!
Geri

Geri Schmaltz
Administrative Officer
ND Public Service Commission
600 E. Boulevard Avenue Dept. 408
Bismarck, ND 58505-0480
Phone: 701-328-4076   Fax 701-328-2410

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BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of Montana-Dakota Utilities Co.,
A Division of MDU Resources Group, Inc.

2016 Electric Rate Increase

Application

Case No. PU-16-666

DIRECT TESTIMONY

OF

SARA CARDWELL

ON BEHALF OF THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

ADVOCACY STAFF

February 24, 2017

Q: Provide your name and qualifications.

A: My name is Sara Cardwell. I am a Public Utility Analyst with the North Dakota Public Service Commission (Commission). I have more than 35 years of utility regulatory experience. In addition to working for the Commission, I have worked for PacifiCorp, Portland General Electric Company, Xcel Energy and Montana-Dakota Utilities Co.

I received a Bachelor of Science Degree in Business Administration from the University of Wisconsin-Stout and received my Masters in Business Administration from the University of Portland. I have testified before this Commission as well as the Public Service Commission of Montana, the California and Idaho Public Utilities Commissions, the Oregon Public Utility Commission and the Washington Utilities and Transportation Commission.

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

A: The Commission appointed me to Advocacy Staff (Staff) in this proceeding. As such, I will present recommendations on a variety of issues in regards to changes the Commission should consider in order to improve the Company's ratemaking process. The resolution of these issues will improve the ratemaking process, streamline filings and result in improved understandings between the Staff and the Company. Some of these issues have been discussed with the Company previously, but need Commission action in order to implement changes.

Q: Please provide a brief summary of the issues you will address.

A: I will address the following issues:

1. Off-Peak Demand Charges;
2. Interest rates on deposits;
3. Billing demand based on 15 minute rolling intervals;
4. Meter Data Management Systems;
5. Employee/Retiree discounts;
6. Contract Rates;

7. The time and manner of filings section in rider tariffs; and
8. The Company's Fuel and Purchased Power Adjustment Rate 58 pricing and filings.

Q: What are the issues with off-peak demand charges?

A: In this case, the Company is proposing to add a $2.00 per Kw Off-Peak Demand charge to Schedule 31 for when the customer's demands during the off-peak period exceed the customer's on-peak demand. While there are reasons for having an off-peak demand charge in excess of the on-peak charge, there are also reasons why this is not a good idea. In general, utilities should encourage customers to peak during off-peak periods. Instituting such a charge can discourage customers from moving certain business operations to the off-peak period. However, on the flip side, if we were seeing customers installing demand control devices and/or on-site generation that was lowering demands in the on-peak period but not in the off-peak period, this charge would have some merit. To date, demand control devices and on-site generation to lower on-peak demands do not seem to be in use in North Dakota.

There has not been a clear purpose explained for this proposed change. In Data Request Response 1.35, the Company stated: "Charging for the increment above the on-peak recognizes that capacity related costs also exist in the off peak and the charge provides cost recovery for those costs at a cost much less than the on-peak charge. The customer moving a higher percentage of demand to the off-peak will pay less than if the customer were to maintain that load in the on-peak hours."

In asking further about this charge, the Company stated in their response to 4.4:

> "The off-peak demand charge is a recognition of the distribution demand costs that were previously recovered through the energy charge."

In response to 7.1 the Company stated that "The off-peak demand charge of $2.00 represents a contribution toward the demand costs identified for the class that are not recovered through the on-peak demand charge."

Seeing that the Company has provided three different reasons for proposing this charge that don't match up, Staff is concerned that the Company proposed this change without really thinking the issue through. In looking at the customer data, there only appears to be one customer that has substantial off-peak demands in excess of on-peak demands. The Company should find out why this particular customer is using more off-peak rather than implementing a charge to provide a disincentive to the entire customer class. Furthermore, if the on-peak demand charges are not cost based, then instituting a demand charge for the off peak demand that should really be assigned to on-peak period is not the correct price signal.

The Company has 6,684 secondary voltage level customers on Rate Schedule 30 and 68 secondary voltage level customers on Rate Schedule 31 yet it is not proposing this charge for Schedule 30. One would think that with the larger number of customers, there would be more of a need for an off-peak demand charge on Rate Schedule 30. Additionally, this proposal will recover less than one percent of the revenue assigned to Rate Schedule 31, meaning there is little benefit to this charge.

The Company is also planning on lowering its Basic Customer Charge to this customer group. In summary, Staff recommends the Company's proposal to institute an off-peak demand charge should be rejected. A better approach to solving what might be the Company's real issue would be to keep the customer charge at its current level and consider further increases to the on-peak demand charge.

Q: Please explain Staff's concern with the interest rate on deposits.

A: Utilities in North Dakota are allowed to collect a deposit from customers when there is a concern that the customer may be a credit risk. The utilities are required to calculate interest on this deposit amount so that if the customer proves themselves not to be a credit risk after 12 months the deposit plus interest is returned to customers. The interest rate on the deposits is updated annually based on the Bank of North Dakota's interest rate on a six-month Certificate of Deposit. Montana-Dakota has a "Fly Sheet" as part of their tariff that indicates this interest rate. However, customers normally do not look at tariffs and generally don't even know what they are.

Staff asked the Company how a customer is informed as to the interest rate. The Company responded:

> "When discussing the need for a deposit with the customer, the customer service representative informs them that the deposit will be held on their account for 12 months, and after 12 months of good payment history, the deposit will be returned to the customer, plus any interest earned. The rate of interest is provided upon request."

The customer should not have to request information on the interest rate. The customer service representative should be instructed to provide this information in all cases. Furthermore, to ensure that customers are adequately informed, the Company website should provide information as to what is involved to become a customer including when a deposit is required and what the interest rate is on that deposit.

Q: Why do you recommend that the Company move to using rolling demands for billing customers?

A: In this day and age, with all the computer, metering, meter reading and billing system advances, the use of rolling demands for the billing of customers is a convenient and fair way to ensure that customers are being billed correctly. It is interesting that a Company that believes off-peak demand billing is necessary would state it doesn't believe there are customers on the system that are peak splitters so rolling demand intervals are unnecessary. In reality, peak splitters are a bigger issue for utilities than off-peak system users.

It is important to understand how a rolling demand interval works. Currently Montana Dakota bills customers based on the highest averaged 15-minute demand interval that occurs during the billing month. The 15 minute periods being used start on the hour, then the next fifteen minute period starting at 15 minutes after the hour, then 30 minutes after the hour begins, etc. A rolling demand still covers a 15-minute period but that 15 minute period reading occurs every 5 minutes. Thus, the customer is billed on the highest 15-munite demand occurring over any 15-minute period. This means that a customer that might currently be starting up machinery say at 10:13 am and shutting it down at 10:17 am in order that the start-up and shut down occurs over two read cycles can no longer split its loads over two periods. With rolling demands, this customer will see a more accurate bill that reflects the customer's actual costs to the system. Xcel Energy and Otter Tail Power bill on rolling demand intervals and many other utilities do as well.

Q: Is this something that you recommend the Company do as a result of this rate case?

A: It takes time for a Company to make such a change. Staff's recommendation is that the Company study moving to rolling demand intervals as part of research into a meter data management system. Staff asserts the Company should develop a concrete implementation timeline for moving to using rolling demand intervals for billing either as part of a meter data management system or separately before or as part of the Company's next rate case.

Q: Please describe what a meter data management system is.

A: When utilities first started implementing automated meter reading systems, the goal was to have data available to help utilities, customers and regulators better know the customers and how they use electricity. But, for many utilities, including Montana-Dakota, all the daily read information just sits unused while customers pay for a system that doesn't furnish any better data than when meters were read monthly by meter readers. And, depending on the rural versus urban nature of the utility, customers might see lower costs if meter readers were still reading meters.

In summary, customers are currently paying for a system that does not provide them, the Company or regulators with the informational benefits that were claimed as the reason an automated reading system was necessary in the first place. With the ability to access daily read data, the Company can employ advanced billing and pricing concepts such as rolling demand intervals or residential demand charges. The Company would also be able to provide customers with better information as to when they use electricity and how they might better control bills.

So, in addition to Staff's recommendation regarding billing demand based on rolling demand intervals, Staff recommends the Company implement a meter data management system prior to filing its next rate case so it can engage in serious rate design discussions.

Q: Please describe your concerns with the Company's employee discounts.

A: Section 10 of the Company's Rate Schedule 100 discusses discounts for qualifying employees. In response to Data Request 4.9 the Company stated that discounts are only provided to retirees that retired on or before December 31, 2009. In order to eliminate confusion, the Company should be required to change the language of this section of their tariff to clearly state that the discounts are only provided to this group of retirees.

Q: Please identify the Company's contract rates.

A: While the Company may have customers sign standard service agreements, Staff's concern is not with standard service agreements. Our concerns are with the Company's contracts for discounted pricing. There are three customers on Rate 30 Contract Rates, three customers on Rate 38 Interruptible Service and one customer on what the Company calls Rate 39 Interruptible Large Power Service. (The Company does not actually have a tariff schedule entitled Rate 39.) The Company also has a rate schedule entitled Firm Service Economic Development Rate 34 under which a customer receives discounts that gradually decrease over the five-year contract period.

Q: Please describe Staff's concern with Firm Service Economic Development Rate 34.

A: Staff's concern is that the Company has proposed removing the following language from the tariff: "Contracts shall be filed with and approved by the North Dakota Public Service Commission." The Company did not state any reasons why it wants this provision removed in its direct testimony but did respond to a discovery request. Staff asserts that these contracts should continue to be reviewed.

Q: Why does Staff assert contract review is necessary?

A: As per the orders approving discount rate contracts in the past, the Company reports the contract delta associated with its contracts every year in its annual report. The table below shows the contract deltas since 2009:

2009	$ 620,240.00
2010	$ 505,930.00
2011	$ 543,909.00
2012	$ 606,617.00
2013	$ 621,790.00
2014	$ 1,060,777.61
2015	$ 1,318,511.76
2016	$ 2,287,255.51

As shown in the table above, the deltas took a dramatic leap in 2014 and have continued to grow significantly in the last few years. Absent the special contracts, the Company's request in this case might have been less. The Company has a responsibility to consider all ratepayers. If the same contracts remain in effect for a number of years without review, it is not a given that the discounts remain reasonable.

The most recent order for a special contract Electric Service Agreement was issued in 2007. The order in that case stated, "At the time of MDU's next electric rate increase request or rate review proceeding, the Commission will review MDU's overall revenue requirements and will specifically review the revenue impact resulting from special contracts." While there was some level of review in the 2010 case, the Company did not provide information in this case that would allow for Staff review of these contracts in this case. The contracts appear to have an initial term of 5 years and then are automatically renewed until either party decides a change is needed. With the exception of one contract, each of these special contracts currently in effect have been in effect for longer than five years without modification.

When asked in Data Request 8.2, the Company stated the contracts are now under review. The Company needs to provide justification to the Commission as to why the existing special contracts are still appropriate. If Staff is not involved in the approval of contracts going forward, the Company may negotiate contracts that are not in the best interests of all ratepayers and keep contracts in place for longer than may be appropriate. Because it appears the Company has begun a review of these contracts, Staff recommends that the Commission require the Company to file its justification and terms for each of the special contracts currently in effect and explain why the contracts and terms are still appropriate or file a revised contract. Staff will review the Company's information and, or revised contracts and present recommendations to the Commission regarding each contract.

Q: Please describe Staff's concern with the Company's "Time and Manner of the Filing" section on each of its rider schedules.

A: The Commission regulates three investor owned utilities in this state that provide electric service. Each of these utilities has riders in place. Each of these utilities files a monthly fuel clause adjustment which is not at issue here. Our concern relates to the annual rider updates. Two of the electric utilities, Otter Tail and Xcel Energy, file their annual rider updates providing Staff with a three to four months review period.

Montana-Dakota files its annual rider updates presuming the Staff can complete its review in 30 to 60 days. The Company states in the Time and Manner of the Filling section of its rider tariffs that the Commission is allowed a 30 or 60 day review period, depending on the rate schedule. Staff requested the Company remove this section from their rider tariffs as it is difficult to accomplish a review in this short period of time. Note that the need for more time isn't based on just Staff's need but, the entire review process which includes issuing notice requirements and scheduling an informal or formal hearing. The Company also needs to provide notice to customers in their bills that it has made a filing which requires a month in order that the notice be sent out in each of the monthly billing cycles.

Based on Staff's experience, it is difficult to process these cases in less than 90 days. In response to the Staff's data request on this issue, the Company stated:

> "the preference would be to not exceed 60 days for annual updates to existing rate riders. The inclusion of 60 days provides for the availability of the most recent costs and/or projections be included in the proposed rates. The further the minimum number of days is extended the less actual cost and known variables are included and replaced with projections of those variables."

Note that all three utilities are allowed to include true-ups each year for differences in actuals versus what was filed the previous year so the Company's stated basis for such a short review period is not critical. Staff has not noticed problems with the longer review period allowed by Xcel Energy and Otter Tail Power. Staff requests the Company remove this section from each of its rider tariffs and provide for a minimum 90-day review period.

Q: Does the Staff have recommended changes for the Company's Fuel and Purchased Power Adjustment Rate 58?

A: The Staff has a number of recommended changes which are as follows:

- Rather than the monthly filing being based on a change from the Base Fuel and Purchased Power costs approved in a general rate case, the monthly filings should be based on the total applicable costs for the month. This will make the filing consistent with the amount shown on the customer's bill and reduce potential errors by eliminating the need to calculate the billing rate as base costs plus or minus the monthly change.

- Eliminate the monthly changes to the tariff. Montana-Dakota is the only utility of the three North Dakota regulated electric utilities that files a tariff as part of their monthly update. The other two utilities provide tables on their websites where the monthly fuel cost are easy to find. Montana-Dakota files a tariff and the only way a customer can find the costs are to find the tariff, then add or subtract the amount on the tariff from the amount on the applicable rate schedule. Having a convenient table on the website versus a monthly tariff reduces regulatory impact, improves customer understanding and will eliminate the need for the Commission to return proof of receipt of the tariff change to the Company.
- Exclude MISO Schedule 24 charges from the Fuel and Purchased Power costs. Neither Xcel Energy nor Otter Tail include these costs in their monthly fuel costs. This is a MISO administrative cost. MN determined because it is an administrative cost, it should be included as part of the utilities' base rates similar to other administrative costs. Additionally, MN determined by excluding this cost from the fuel costs, the utilities have a greater incentive to encourage MISO to keep its administrative costs in check.

Montana-Dakota argues that the Schedule 24 costs change monthly, they should be considered part of the fuel costs and they shouldn't have to do what the other two utilities are doing. These arguments are not persuasive. Administrative costs do not belong in the fuel cost adjustment. By excluding these costs from the fuel costs, we can provide an incentive for utilities to work with MISO to ensure their administrative charges are reasonable and prudent. Staff would also like to see more consistency across the utilities in the monthly fuel cost adjustment filings.

- Another way to improve consistency is if all the utilities true-up their fuel cause adjustments on a monthly basis. Currently Otter Tail and Xcel Energy employ a monthly true-up. Montana-Dakota performs an annual true-up. Staff does not see that a monthly true-up adversely affects the costs to customers. In fact, it may actually help customers as a large positive or negative balance does not occur with this method. Therefore, Staff recommends that Montana-Dakota change to a monthly true-up versus an annual true-up. As part of its compliance filing to implement the final rates in this case, the Company should provide information as to the best timing to change from an annual to a monthly true-up.

Q: Please summarize your recommendations.

A: The Staff's recommendations are:

1. Montana-Dakota's proposal for an Off-peak Demand Charge and a decrease to the Basic Service Charge on Schedule 31 should be rejected;
2. The Company shall add information to its website in a clearly marked fashion regarding when customers are required to pay deposits and what the interest rate on deposits is;
3. The Company shall propose changing to billing demand based on 15-minute rolling intervals in its next rate case;
4. The Company shall institute a Meter Data Management System before its next rate case;
5. The Company shall modify Section 10 of Rate Schedule 100 to state that the discount is only available to retirees that retired on or before December 31, 2009;

6. The Company shall file its justification, or new contracts, for all of its special contracts within the next six months for further Commission review;
7. The Company shall eliminate the time and manner of filings section in rider tariffs and file its annual rider updates to allow for a minimum 90-day review period; and
8. The Company shall modify its Fuel and Purchased Power Adjustment Rate 58 pricing and filings as stated above.

Q: Does this conclude your testimony?

A: Yes, it does.

STATE OF NORTH DAKOTA

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Application of
MONTANA-DAKOTA UTILITIES CO.,
A Division of MDU Resources Group, Inc.
for authority to Increase Rates for Electric Service in North Dakota

Case No. PU-16-666

AFFIDAVIT OF
Sara Cardwell

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

Sara Cardwell

Sara Cardwell

Subscribed and sworn to before me
this **24th day of February, 2017.**

Notary Public

SEAL

JOHN G. HAMRE
Notary Public
State of North Dakota
My Commission Expires July 04, 2020

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of Montana-Dakota Utilities Co.,

a Division of MDU Resources Group, Inc.

2016 Electric Rate Increase Application

Case No. PU-16-666

DIRECT TESTIMONY

OF

RICHARD A. POLICH, P.E.

ON BEHALF OF THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

ADVOCACY STAFF

February 24, 2017

Table of Contents

Q. Please state your name and place of employment.

A. My name is Richard A. Polich. I am employed by GDS Associates, Inc. ("GDS"), and my office is located at 1850 Parkway Place, Suite 800, Marietta, Georgia 30067.

Q. What position do you hold?

A. I hold the position of Managing Director.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this testimony on behalf of North Dakota Public Service Commission Advocacy Staff ("Staff").

Q. What is your educational background?

A. I graduated from the University of Michigan - Ann Arbor in August 1979 with a Bachelor of Science Engineering Degree in Nuclear Engineering, and a Bachelor of Science Engineering Degree in Mechanical Engineering.

In May 1990, I received a Master of Business Administration from the University of Michigan - Ann Arbor.

Q. Please describe your work experience.

A. In my role as both employee and consultant, I have had over 37 years of work experience in the energy sector, performing duties and services for a myriad of companies and organizations, and representing the interests of private and public constituencies throughout the country.

In May 1978, I joined Commonwealth Associates, Inc., located in Jackson, Michigan, as a Graduate Engineer and worked on several plant modification and new plant construction projects.

In May 1979, I joined Consumers Power Inc. (now called Consumers Energy), located in Jackson, Michigan, as an Associate Engineer in the Plant Engineering Services Department.

In April 1980, I transferred to the Midland Nuclear Project and progressed through various job classifications to Senior Engineer. I also participated in the initial design evaluation of the Midland Cogeneration Plant.

In July 1987, I transferred to the Market Services Department as a Senior Engineer and reached the level of Senior Market Representative. While in this department, I analyzed the economic and engineering feasibility of customer cogeneration projects.

In July 1992, I transferred to the Rates and Regulatory Affairs Department of Consumers Energy as a Principal Rate Analyst. In that capacity, I performed studies relating to all facets of development and design of Consumers Energy's retail gas and electric rates and electric wholesale rates. During this period, I was heavily involved in the development of Consumers Energy's Direct Access program and Consumers Energy's Retail Open Access program. I also participated in the development of Consumers Energy's revenue forecast.

In March 1998, I joined Nordic Energy, LLC ("Nordic"), located in Ann Arbor, Michigan, as Vice President in charge of marketing and sales. My responsibilities included all aspects of obtaining new customers and enabling Nordic to supply electricity to those customers. In May 2000, my responsibilities shifted to Operations and Regulatory Affairs. My Operations responsibilities included management of supply purchases, transmission services, and development of new power projects. My Regulatory Affairs responsibilities included overseeing regulatory and legislation issues for the company.

In March 2003, I formed Energy Options & Solutions, based in Ann Arbor, Michigan, as a consulting concern focusing on providing engineering services and regulatory support. Through my work with Energy Options & Solutions, I gained extensive experience consulting in the areas of project development and economic analysis with renewable energy companies across the country, including: Noble Environmental Power located in Centerbrook, Connecticut; Third Planet Windpower, LLC located in Palm Beach Gardens, Florida; TradeWind Energy, LLC located in Lenexa, Kansas; Windlab Developments USA located in Canberra, Australian Capital Territory, Australia; and Matinee Energy Inc. located in Tucson, Arizona, among others.

Other examples of my consulting work have included evaluation of the Arkansas Weatherization Assistance Program for the Arkansas Energy

Office, and providing the West Michigan Prosperity Alliance with an evaluation of the business opportunities for Western Michigan businesses in the renewable energy business sector.

In 2007, I served as primary author of the report on the economic impacts of renewable portfolio standards and energy efficiency programs for the Department of Environmental Quality – State of Michigan.

In 2011, I joined KEMA, Inc. ("KEMA") located in Burlington, Massachusetts, as a Service Line Leader responsible for developing its renewable energy consulting business. While at KEMA, I performed multiple renewable energy studies for the Electric Power Research Institute, including a renewable energy options study for the country of Saint Maarten (a constituent country of the Kingdom of the Netherlands). I also assisted Lake Erie Energy Development Corporation in its successful application to the U.S. Department of Energy for a multi-million dollar grant to develop an offshore wind project in Lake Erie.

In 2013, I joined CLEAResult located in Little Rock, Arkansas, as Director of Operations. My primary responsibility involved supporting program operations in assisting the company's Arkansas unit to successfully meet a 400% increase in energy efficiency goals that it managed for Entergy. I was also responsible for managing the company's natural gas energy efficiency programs in the State of Oklahoma.

In 2015, I joined the Georgia office of GDS Associates, Inc., a consulting group focusing on utility engineering and consulting services, as Managing Director in its Generation Services area.

A copy of my Curriculum Vitae is attached hereto and incorporated herein as Exhibit PSC-1.

Q. Do you have any professional registrations?

A. Yes, I am a registered Professional Engineer in Michigan and hold a LEED Green Associate credential from the U.S. Green Building Council.

Q. Have you published any papers?

A. Yes, I have authored the following publications:

- Engineering and Economic Evaluation of Offshore Wind Plant Performance and Cost Data, 2011, Produced for the Electric Power Research Institute, KEMA, Inc.
- Island of Saint Maarten Sustainable Energy Study, 2012, Produced for the Cabinet of Ministry VROMI, KEMA Inc.
- A Study of Economic Impacts from the Implementation of a Renewable Portfolio Standard and an Energy Efficiency Program in Michigan, 2007, Produced for the Michigan Department of Environmental Quality
- Alternative and Renewable Energy Cluster Analysis, 2007, Produced for the West Michigan Strategic Alliance and The Right Place

Q. Have you testified in any other regulatory proceedings?

A. Yes, I have testified before the Michigan Public Service Commission on multiple occasions as a representative of Consumers Energy, and on behalf of Energy Michigan. I testified before the North Dakota Public Service Commission ("Commission") on behalf of the Staff in Case No. PU-15-96, "In the Matter of Northern States Power Company's Advance Determination of Prudence for its 345 MW Power Purchase Agreement with Mankato Energy Center". In January 2016, I testified on behalf of SunEdison, Inc. in Docket No. 2015-0022 before the Public Utilities Commission of Hawaii, In the Matter of the Application of Hawaiian Electric Company, Inc. Hawai'i Electric Company, Inc., Maui Electric Company, Limited and NextEra Energy, Inc. for Approval of the Proposed Change of Control & Related Matters" (NextEra sought to purchase Hawaiian Electric, et all.). Attached hereto and incorporated herein as Exhibit PSC-2, is a list of proceedings detailing my prior participation as a testifying witness.

Testimony Purpose and Summary

Q. What is the purpose of your testimony?

A. The North Dakota Public Service Commission Advocacy Staff ("Staff") hired GDS Associates, Inc. ("GDS") to provide an analysis, recommendations and testimony in regard to Montana-Dakota Utilities

Co., a Division of MDU Resources Group, Inc. (MDU) 2016 Electric Rate Increase Application. My testimony will cover five areas, including; Proposal for overall rate of return; Adjustments to electric rate base; Cost of Lewis & Clark Reciprocating Internal Combustion Engine Project ("RICE Project"); Decommissioning Expense; and Revenue Requirement.

Q. Please summarize your testimony.

A. My testimony addresses MDU's overall rate of return, adjustments to plant in service and revenue requirement. I am recommending that the Commission base MDU's rate increase using the 2017 Projected Test Year based upon 2016-year end actual cost of service provided in Discovery Response 1.1. I further recommend the Commission approve an overall rate of return of 6.789% on plant in service based upon an 8.53% return on equity. My testimony includes several disallowances in MDU's proposed plant in service resulting in a Project 2017 Rate Base of $520,229,030, excluding wind resources. Last, I am recommending the Commission approve adjustment to MDU revenues (see Exhibit PSC-3) as follows:

1. Base Rate Revenue Increase: $515,316
2. The Renewable Rider Decrease: $1,775,588
3. Transmission Cost Adjustment Revenue Decrease: $674,367

Q. What are your other key Commission recommendations in this proceeding?

I am recommending the following additional changes to MDU's rate increase request:

1. MDU's proposal for collection of decommissioning funds to be used for the decommissioning of existing plants should be rejected. The accounting treatment proposed by MDU places all the risk with the North Dakota ratepayers and all the rewards with MDU. MDU would be allowed to claim the revenue from the decommissioning expense as revenue and profit without any corresponding liability, resulting in additional shareholder profits. In the event of MDU over collection of funds to finance decommissioning, ratepayer's refunds would be less than the amount paid in to the fund (see page 26 of my testimony). This change reduces MDU annual revenue requirement by an estimated $1,900,145.
2. MDU capitalization for recovery of losses on employee housing, should be disallowed. First, accounting treatment for this type of cost should be as an O&M expense in the years in which the cost occurred. Second, if this was not for temporary housing associated with employees being temporarily located at a job site, it is not recoverable. Third, MDU had other options of

supplying employees with housing which would have resulted in less cost (see page 30 of my testimony). This change reduces MDU annual revenue requirement by an estimated $95,003.

3. Reduced incentive compensation and bonuses by 60% of the amount MDU forecasted to be consistent with Commission decision in Case PU-10-124 (see page 31 of my testimony). Incentive compensation and bonuses are established to improve company performance with the intention of benefiting company shareholders. Ratepayers should not be required to pay these costs because they do not provide any benefit to ratepayers.
4. $ 12.27 million of MDU's cost for the Lewis & Clark RICE Project should be disallowed. This project was almost 70% higher than costs for similar types of generation resources. MDU's justification of an expedited project completion schedule, is not valid because MDU had opportunities to mitigate the situation and/or alternative options (see page 32 of my testimony). This change reduces MDU annual revenue requirement by an estimated $1,460,482.

Q. How is your testimony organized?

A. I have organized my testimony into the following sections:

1. **Overall Rate of Return** – Calculation of return on equity (ROE) and overall rate of return (ROR).
2. **Decommissioning Expense** – Address MDU's request to include cost of decommissioning of future retired generation facilities in rate base.
3. **Other Adjustments to Electric Rate Base** – Recommendations for adjustments to costs incorporated into electric rate base.
4. **Lewis & Clark RICE Project** – Review of the need, timing and cost of this generation resource.
5. **Revenue Requirement** – Calculate MDU's revenue requirement and revenue deficit

Q. Have you prepared any Exhibits?

A. Yes, the following is a list of Exhibits included with my testimony:

EXHIBIT	DESCRIPTION
PSC-1	Richard A. Polich Curriculum Vitae
PSC-2	Regulatory Proceedings Testimony List
PSC-3	2017 Projected Operating Income and Rate of Return
PSC-4	DCF Calculation
PSC-5	Example of Flotation Cost Over Recovery
PSC-6	Decommissioning Cost to Montana Ratepayers
PSC-7	List of Similar Small Power Project Costs

Q. Are you sponsoring any Revised Statements?

A. Yes. Since we are recommending basing MDU's rate increase on a 2017 Projected Test Year based upon 2016-year end actuals, all of MDU's Filed Statements need to be revised. I am sponsoring those statements I used in developing my revised plant in service and income statement. This includes Statements A, B, G, I and J.

Overall Rate of Return

Q. What is the definition of cost of common equity?

A. The cost of common equity or Return on Equity (ROE) is often defined as the compensation the market demands in exchange for owning the asset and bearing the risk of ownership. It is a percentage applied to the common equity portion of a utility's capital to calculate the utility's potential gross profit. It is a component of a utility's Rate of Return (ROR), which also includes interest on debt and dividends on preferred stock.

Q. What was the basis for your method of calculating the ROE?

A. There are several legal cases which establish the criteria and standards for determining the ROE. The criteria incorporated into my calculations were based upon standards set in the U. S. Supreme Court decisions in *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*"), and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"). This establishes that ROE should be commensurate with the returns on investments in other enterprises having corresponding risks and should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital.

Q. Describe your approach to determining the appropriate rate of return on common equity for MDU.

A. My first step was a review of MDU's witness, J. Stephen Gaske's testimony, exhibits and review of various discovery responses regarding cost of common equity based upon his Discounted Cash Flow analysis. Second, I have reviewed the cost of common equity testimony of witnesses in other MDU proceedings and various decisions of regulatory agencies. Last, I conducted my own analysis based upon data that better reflects the requirements of investors willing to risk capital in the equities market.

Q. Do you agree with the methodology used by Mr. Gaske in his direct testimony?

A. Mr. Gaske's use of Discounted Cash Flow ("DCF") analysis is the appropriate model for calculating return on common equity. I do not agree with his approach to the determinates used within that model or his calculations. Specifically, his selection of utilities used in the DCF calculation was too small, resulting in a statistically inferior sample set (see page 23 of my testimony). Mr. Gaske's application of a flotation cost (see page 15 of my testimony) adjustment factor is inappropriate. In addition, he used the wrong quarterly dividend growth factor multiplier (see page 14 of my testimony).

Q. Is the 10.0% ROE presented by Mr. Gaske a just and reasonable ROE for MDU?

A. No. First, Mr. Gaske's assumption that the market does not already factor in investor anticipation of increased interest rates is not realistic, as I discuss in my testimony, starting on page 18. Second, the flotation cost adjustment is inappropriate since MDU has no intention of raising additional capital from common stock issuances and these costs are already included in MDU's current capital structure. Third, Mr. Gaske chose a select group of utilities which were based upon unnecessarily restrictive criteria resulting in a very small sample size.

Q. What DCF methodology have you employed in calculating an appropriate ROE for MDU common equity?

A. I have employed a readily accepted methodology utilized in various state and federal regulatory proceedings. I applied the Federal Energy Regulatory Commission (FERC) two-step DCF methodology, as outlined in FERC Opinion No. 531, to a representative group of national utilities. The DCF model is based upon the principle that rational investors evaluate the risks and expected returns of securities in capital markets and establish a price for a particular security which adequately compensates them for the risks they perceive. The DCF model incorporates the proposition that the total return received by shareholders consists of dividends and capital gains, and these are measured in terms of the current dividend yield plus the expected rate of dividend growth. The DCF Formula is as follows:

$$k = (D/P)\ (1 + 0.5g) + g$$

Where:

k: Total return to investors

D: Dividend on common stock

P: Price of common stock

g: Expected long-term dividend growth rate

The "D/P" term provides the dividend yield. The "g" term is calculated based upon a weighted average of two-thirds short-term growth rate and one-third long-term growth rate. The short-term growth rate is based upon analysts' five year forecasted earnings projections. The long-term growth rate is the projected long-term US economic growth rate. The "(1+.05g)" multiplier to the dividend yield reflects typical utility quarterly dividend payments.

Q. Do you agree with Mr. Gaske's quarterly dividend multiplier?

A. No. Mr. Gaske's use of a dividend multiplier of (1+.0625g) is inappropriate. First, the use of a dividend multiplier of (1+.05g) is the recognized normal method of adjusting the dividend yield for quarterly dividend payments.

Markets reflect the timing of dividends in stock prices, resulting in dividend yield calculation of the DCF calculation also reflecting the timing of dividends. Mr. Gaske's argument of inflating the dividend multiplier to reflect an average of the timing for the payment of dividends results in double counting for market timing.

Q. How did you determine the long-term US economic growth rate?

A. The long-term US economic growth rate I used is based upon an average of long-term GDP data from Energy Information Administration, Social Security Administration and HIS Global Insights. The expected long-term US economic growth rate used in my DCF calculation is shown in Exhibit PSC-4.

Q. Why do you feel it is inappropriate to include a "flotation Cost Adjustment" in the ROE calculation?

A. In Mr. Gaske's testimony (page 20, lines 4-9), he defines "flotation costs" to be the cost associated with the issuance of "*new common equity*". Mr. Gaske then goes on to state that his "flotation cost adjustment" should be applied to "... the entire common equity investment ..." (Mr. Gaske's testimony, page 21, line 8). This inclusion of flotation costs in the ROE calculation would result in double recovery of costs and compensate MDU for costs they are not likely to incur. In addition, the 3.2% flotation costs Mr. Gaske used (Mr. Gaske's testimony, page 20, line 13), is not realistic because the cost of new equity depends upon the amount of equity being raised and the manner in which it is being raised. In fact, MDU stated in Discovery Response 5.1 that in 2015 it received 115 million in equity which did not incur any issuance costs. The flotation costs of MDU's 2014 common stock offering was approximately 1% (Discovery Response 2.9), much lower than Mr. Gaske's 3.2%. Applying the 3.2% flotation cost adjustment would result in MDU receiving revenues from North Dakota ratepayers for costs it had not incurred.

Mr. Gaske's position that flotation costs should be applied to existing equity because there is the potential for the company to issue new common equity is also double recovery. Any flotation costs for existing common equity has already been paid for by MDU ratepayers and is reflected in MDU's capital cost structure. In the event MDU elects to issue future common equity, MDU can request recovery of the cost of issuing new common equity in a future rate proceeding. MDU stated in Discovery Response 2.9 that flotation costs have not been included for recovery in previous rate proceedings and the equity recorded on its books is net of issuance costs.

Last, utilities very seldom issue new stock to raise common equity, funding operations and capital requirements from earnings and recovery of initial capital investment through their rates. MDU's current capital requirements do not appear to indicate a need to raise additional capital, because the amount recovered in rates through depreciation will cover the cost of expected capital improvements. In Discovery Response 2.9 states that MDU does not have any plans to issue new common equity to support operations. In addition, MDU's debt to equity ratio is well within the expected D/E ratio of public utilities, thus additional equity is not needed. In summary, MDU is unlikely to incur flotation costs of issuing new equity in the near future. If they do issue new equity, MDU can attempt to recover the common equity issuance costs through a future regulatory proceeding.

Q. Would Mr. Gaske's flotation cost adjustment recover the appropriate amount of flotation costs?

A. No. The multiplication of the investor required return by the flotation cost adjustment is wrong mathematically and would result in MDU over recovering the flotation costs by 64%. I have provided an example of the flotation cost recovery proposed by Mr. Gaske in Exhibit PSC-5. The over recover occurs because the 3.2% flotation cost adjustment to is applied each year over the life of the asset. Using Mr. Gaske's approach of multiplying the ROE by the flotation cost adjustment and applying over the life of asset would result in ratepayers paying the total actual flotation costs by the end of year 16. This leaves the utility an additional 24 years of excess flotation costs recovery which results in unjustified profits. The ratepayer is much better off paying the flotation costs at the time the MDU incurs the need to increase equity. *It is my recommendation that the Commission should never include a flotation cost adjustment in the* *calculation of cost of capital because it will always result in excessive recovery of flotation costs.*

Q. Do you agree with Mr. Gaske's position that current market conditions are artificial and not normal?

A. No. Mr. Gaske's position is based primarily upon the Federal Reserve's Open Market Committee (FOMC) monetary policy as of September 16, 2016. First, the Federal Reserve raised interest rates by 25 basis points on December 14, 2016. Second the FOMC has indicated it is inclined to raise rates up to three times this year. Third, the consumer-price-index has risen faster over the last few months, indicating a return to normal inflation levels. Fourth, markets reflect not only existing data but anticipated market performance. An indication of market anticipation can be seen in Treasury Bond yields, where the 10-year bond yield has risen from 1.63% in February of last year to 2.51%, a 54% increase in bond yields. Markets are reflecting anticipation of increased Federal Reserve interest rate hikes and higher inflation rates.

Last, the definition of "normal" markets is the equivalent of arguing who is the best baseball player of all time. The conditions of the game of baseball at the time the game is played is a key determinate in the performance of a player. Changes in the game of baseball make it impossible to determine how a player in the 1940s would perform in today's game, too many aspects of the game have changed. The situation is the same with financial markets and company performance. Market conditions are always "normal" during the time at which those market conditions exist. Yes, things like market manipulation by a few players, can skew a market for a short time, but by definition the market still defines the normal condition at the time of that market. Today's investors are more sophisticated, have access to more data and more analytical tools than ever before. They have the ability to find unusual circumstances within markets and can exploit those conditions, but usually only for very short period of time.

Today's market conditions reflect future expectations of performance of the US economy and investors are pricing those factors into utility stock value. In addition, while some have suggested that the current relatively low capital costs are somehow aberrational or artificial, prominent economists like former Federal Reserve Chairman Benjamin Bernanke, former Treasury Secretary Lawrence Summers, and Nobel Prize winning economist Paul Krugman dispel these suggestions and express views in line with the expectation for continued relatively low long-term capital costs. For example, in his March 30, 2015 blog entitled "Why are interest rates so low?" Dr. Bernanke explained:

> ***Low interest rates are not a short-term aberration,*** but part of a long-term trend. As the figure below shows, ten-year government bond yields in the United States were relatively low in the 1960s, rose to a peak

> above 15 percent in 1981, and have been declining ever since. (Emphasis added.)

The figure that Dr. Bernanke presents is a graph of 10-year Treasury bond yields and inflation rates since 1960. Dr. Bernanke notes that the inflation rate, at least partly, explains the pattern of interest rates. In his blog, Dr. Bernanke also answered the "confused criticism" that "the Fed is somehow distorting financial markets and investment decisions by keeping interest rates 'artificially low.'" Dr. Bernanke explains:

> The best strategy for the Fed I can think of is to set rates at a level consistent with the healthy operation of the economy over the medium term, that is, at the (today, low) equilibrium rate. ***There is absolutely nothing artificial about that!*** (Emphasis added.)

In writing in the Financial Times on August 23, 2015, Dr. Summers explained that the state of the global economy dictates that, if we are to achieve satisfactory economic growth, historically low interest rates are now and will be required for quite some time, noting that long term bond markets are telling us that real interest rates are expected to be close to zero in the industrialized world over the next decade. Dr. Summers said:

> Much more plausible is the view that, for reasons rooted in technological and demographic change and reinforced by greater regulation of the financial sector, the global economy has difficulty generating demand for all that can be produced. This is the "secular stagnation" diagnosis, or the very similar idea that Ben Bernanke, former Fed chairman, has urged of a "savings glut". Satisfactory growth, if it can be achieved, requires very low interest rates that historically we have only seen during economic

> crises. ***This is why long term bond markets are telling us that real interest rates are expected to be close to zero in the industrialized world over the next decade.*** (Emphasis added.)

Also, in his August 25, 2015 New York Times opinion column, Dr. Krugman pointed to the evidence over the last seven years that demonstrates that the low interest rates we have been experiencing are not unnatural or artificial.

> The underlying claim in all such demands is that the low interest rates we've had since 2008 are ***"unnatural"*** or ***"artificial"***. So it's probably worth repeating that while very low rates may seem strange, they also seem fully justified by the economic situation. The original Wicksellian concept of the natural rate of interest defined that rate as the rate consistent with stable prices, with an economy that was neither too hot nor too cold. ***If we had had an unnaturally low rate these past 7 years, we should have seen accelerating inflation; we haven't.*** (Emphasis added.)

These prominent economists are saying that our economy, due to both domestic and international influences, has not been capable of sustaining substantially higher interest rate levels over the past several years, and this circumstance is not expected to change significantly anytime soon.

Q. Do you agree with Mr. Gaske's application of a "risk premium" in his DCF calculation?

A. No. Mr. Gaske's claim that MDU's electric operations have a higher risk than other electric utilities because of the percentage of coal generation, is a poor assumption. Utility risk is based upon a variety of functions, including stability of rate base, regulatory environment, debt to equity ratio, ability to meet interest payments, growth forecasts, etc. With the change in federal administration at the US Environmental Protection Agency (EPA) it is likely that the concerns due to recent pollution regulations will be minimal, including those associated with the Clean Power Plan ("CPP"). The new EPA Administrator Scott Pruitt has targeted the repeal or significant overhaul of the CPP. This change in EPA position on the CPP significantly reduces the potential for MDU to have to make costly improvements or shutdown coal generation.

North Dakota's regulatory practice which allows utilities to implement interim rates while requested rate increases proceed through the regulatory process, also reduces MDU's risk in relation to many of the utilities within the Value Line group. Not all states have a policy which allow interim rates to be implemented, resulting in significant delays between utilities incurring costs and being able to recover those costs through rate increases. North Dakota's interim rate practice provides MDU quicker recovery of increased costs, reducing the risk of losses. MDU also enjoys the benefits of a monthly direct pass through of fuel and purchased power costs as well as a number of riders that are adjusted annually to reflect the most current costs which also reduce the Company's risks. In addition, MDU is part of the MISO Regional Transmission Organization which helps to mitigate price risk of generation resources. Last, investors will price higher risk into the price of a stock. If a utility has a higher risk, that risk would be reflected in lower stock prices and is already reflected in the information contained in the Value Line data. This will factor risk into the DCF analysis.

Q. Do you feel Mr. Gaske's selection of representative utilities to be suitable for MDU's DCF calculation of cost of equity, is appropriate?

A. No. Mr. Gaske actually provides the reason not to use his very limited selection of representative utilities in his DCF calculation. As Mr. Gaske notes, electric utility is a division of MDU Resources and investors will treat equity as part of the whole company, not just the electric utility. Investors valuations are typically focused on the earnings and dividends of the whole company. Impact of a segment of a company only partially affects the valuation and investors' decisions.

Q. What was the criteria and selection process for your proxy utility group?

A. I selected a national electric utility proxy group using the following criteria:

(1) Companies that are included in the Value Line electric utility industry universe;

(2) Electric utilities that have an S&P corporate credit rating ("CCR") of BBB to A- [This rating range encompasses one credit rating notch above and below MDU Resources' S&P rating of BBB+. MDU is a division of MDU Resources and does not have S&P and Moody's ratings of its own, and MDU Resources does not have Moody's credit ratings.];

(3) Electric utilities having an IBES published analysts' consensus "five-year" earnings per share growth rate;

(4) Electric utilities that are not engaged in major merger or acquisition ("M&A") activity currently or during the six-month dividend yield analysis period;

(5) Electric utilities that paid dividends throughout the six-month dividend yield analysis period, did not cut dividends during that period, and have not subsequently announced a dividend cut; and

(6) Electric utilities whose DCF results pass threshold tests of economic logic and are not outliers.

Using the three-notch S&P credit ratings screen listed in item 2 above results in selection of utilities independently judged to have comparable risks to MDU. Using this criterion based on MDU's Standard & Poor's Corporate Credit Rating of BBB+, 29 of the companies included in the Value Line electric utility universe have been included in the representative proxy group of utilities. (Exhibit PSC-4)

Q. How did you apply the two-step DCF method to your proxy group of electric utilities?

A. First a single six-month average dividend yield was developed for each proxy company for the six-month period ending January 2017. I then calculated a single average growth rate for each proxy group company using a "short-term" analysts' forecasted "five-year" earnings per share growth rate weighted at two-thirds, and a "long-term" forecasted GDP growth rate with a one-third weighting. For the short-term growth rate, I used the average of the analysts' consensus "five-year" earnings per share growth rate projections for each proxy group company as reported by Yahoo! Finance from the Thomson Reuters/IBES database on January 31, 2017. The long-term growth rate incorporated in my analysis is 4.35%. This growth rate is based on forecasted long-term GDP growth as prescribed by the FERC. The calculation of this recent long-term GDP growth rate was presented by FERC Staff witness Robert J. Keyton, in recent testimony, and the source documents are included in his workpapers available from the FERC's eLibrary on the Internet. The calculations of the dividend yield and composite average growth rates are shown in Exhibit PSC-4.

Q. What was the result of your DCF Analysis?

A. The resulting two-step DCF analysis of proxy utilities yielded a ROE range of 5.49% to 9.94%. The median and recommended ROE for MDU came in at 8.53%. This is after removing the one outlier, Entergy Corporation because the company's growth rate is projected to be negative and the resulting ROE is well below that of all the other proxy utilities.

Q. What is your recommendation for the ROE to be used in calculating MDU's overall rate of return?

A. Based upon the two-stage DCF model and the projected 2017 capital structure for MDU of 51.4% common equity, I recommend the Commission approve a ROE of 8.53% for MDU. As discussed earlier, MDU's level of risk is minor in comparison to other utilities due to the regulatory environment in which it operates and its service area.

Q. What overall rate of return are you recommending for MDU?

A. Based upon the projected 2017 capital structure derived from MDU's 2016-year end actuals, the overall rate of return calculates to be 6.789% as shown in the following Table 1.

Table 1: MDU North Dakota Utility Operations Overall Rate of Return

Capital Type	2017 Projected	Percent	Cost	Overall Rate of Return
Long Term Debt	$600,440,903	42.673%	5.245%	2.238%
Short Term Debt	68,096,270	4.840%	2.402%	0.116%
Preferred Stock	15,258,600	1.084%	4.579%	0.050%
Common Equity	723,295,087	51.403%	8.530%	4.385%
Total	$1,407,090,860	100.000%		6.789%

Decommissioning Expense

Q. What decommissioning expenses has MDU proposed to recover through electric rates in this proceeding?

A. MDU has proposed to collect through its depreciation operating expense, the ***PROJECTED*** future decommissioning expense for each of its generation assets. It appears from Discovery Response No. 1.30 that MDU proposes to include in rates $1,900,146 of decommissioning expense.

Q. How has MDU proposed to account for the decommissioning funds?

A. MDU has not proposed an appropriate method for accounting and capture of this expense. In response to Discovery Question 5.10, MDU proposes to establish an accrual account for tracking collection of decommissioning funds. The funds will not be held in a separate account, but used at MDU's discretion. MDU does not intend to credit the prefunded decommissioning account for interest on the funds it is using for operations. Nor does there appear to be any adjustment to the funds need for operating expenses to account for use of decommissioning funds being used for operations. Unless MDU intends to create a liability account associated with the decommissioning funds, the decommissioning funds collected will become part of net company earnings. Under this arrangement, if MDU were to enter bankruptcy, the decommissioning funds would disappear. This arrangement provides North Dakota MDU ratepayers little to negative value.

Q. Why is there little to no value to North Dakota ratepayers in the collection of decommissioning funds as proposed by MDU'?

A. Under MDU's proposed arrangements for accrual of decommissioning funds, North Dakota ratepayers would effectively be providing MDU a loan on future expenses without being paid any interest. This funding is in today's dollars for a future expense. Today's dollars have a higher value then future dollars due to inflation. What happens to the decommissioning funds if decommissioning costs are lower than projected, the plant remains in service longer, or the plant is sold? If only the accumulated dollars are returned to ratepayers without interest or accounting for time value of money, ratepayers will be refunded less than what they paid. This situation has already occurred in Montana where MDU had been collecting decommissioning funds from its Montana ratepayers. MDU had been collecting decommissioning funds for several decades in Montana with no accrued interest. On December 31, 2014, the decommissioning fund was significantly overfunded by $6,712,194. MDU proposed to refund its customers by decreasing the depreciation expense by $671,219 annually *over a ten-year period.* Assuming the $6.71 million over collection occurred in equal annual amounts over the 20-year basis, adjusting each collected years and refunded years' dollar to 2016-dollar value (year in which MDU began decrease in depreciation), Exhibit PSC-6 shows that MDU ratepayers will have received $2,013,738 less then they contributed in real dollars. That represents 23% in lost value to ratepayers and a gain for MDU. Under MDU's proposed method of accounting for decommissioning funds collected in this proceeding, this is likely to occur to North Dakota ratepayers if the Commission adopts MDU's request for collection of decommissioning funds.

Q. What has been the past experience in North Dakota with MDU's estimation of retirement costs?

A. Discovery Response 5.11 shows the decommissioning costs and revenue recovery from North Dakota ratepayers for several retired power plants prior to 2001. This discovery response shows that MDU received $331,456 more in decommissioning funding from North Dakota ratepayers than it incurred in decommissioning costs, an over collection of almost 13%. These examples of the over recovery of decommissioning costs likely contributed to additional MDU profits.

Q. Are there other examples of decommissioning funding?

Yes. When utilities have been allowed to collect decommissioning costs for nuclear power plants, they are often required to set aside the funds in separate account which accumulates interest. This interest is then used to offset some of the decommissioning costs. Decommissioning expense needs to be tracked and periodically reviewed to see if the level of funding is appropriate.

Q. What other reasons do you have for the Commission to reject MDU's proposal to collect future decommissioning funds?

The projections for the cost of decommissioning existing generation plants contain many, many assumptions regarding retirement timing, cost of retirement, disposition of equipment, salvage value, inflation rates, etc. These assumptions can have a wide range of impacts on decommissioning costs. For example, the assumed life of the new Lewis & Clark RICE Project is 40 years but this type of generation has often been in operation for much longer periods and can easily be refurbished.

Q. What action should the Commission take in this proceeding regarding MDU's request to include decommissioning expense in its revenue requirement?

A. I recommend the Commission reject MDU's request to include decommissioning expense associated with projected future generation asset retirement. The complications of accounting treatment, assumptions used to determine the level of decommissioning expense, tracking of funds, interest on decommissioning funds, future reconciliation process and other issues have not been adequately addressed by MDU in its testimony. MDU's past history of estimation of decommissioning costs and methods of ratepayer funding have resulted in over recover by MDU and ratepayers incurring higher rates then should have occurred.

Other Adjustments to Electric Rate Base

Q. Do you recommend any other adjustments to MDU's electric rate base?

A. Yes. MDU has requested to recover the loss on sale of manufactured housing it purchased to house employees. On pages 35 and 36 of Mr. Jacobson's testimony, the reason for the purchase and loss on the sale of manufactured housing is discussed. As should have been expected, when a shortage occurs within a housing market, builders move to fill that shortage with new homes, which is what occurred in this instance. MDU should have known that the housing stock would catch up with demand and made other arrangements, such as helping its workers procure rental manufactured units. These are readily available and could have been used to provide employees housing.

In addition, there are several accounting issues with his cost item. If the housing was for temporary employee housing due to temporary relocation to a job site, then usual utility practice is to expense the temporary housing as an O&M expense. If it was not for temporary housing associated with temporary relocation, then the cost of the housing should have been paid for by the employee because it was for purposes of permanent residence. In either of these situations, this is not a legitimate capital investment and should have been treated as an O&M expense. Thus, these costs should have been paid through MDU's operating expense account and do not belong in rate base.

Q. How should the Commission treat employee bonus and incentive compensation?

A. The Commission should apply the same principals to MDU incentive compensation and bonuses as was applied in Case PU-10-124. In that proceeding, incentive compensation and bonuses were reduced by 60%. I have made the adjustment in Statement K workpapers, resulting in a reduction of $1,313,132 in labor costs. The MDU's figures in cells G37 and G38 of MDU Statement K Workpapers, K-152-153, were reduced by 60%. The resulting labor costs shown in cells G57-64 of Statement K Workpapers, K-152-153, were entered into the Income Statement spreadsheet, Labor Tab, cells F10-17.

Lewis & Clark RICE Project

Q. Have you reviewed MDU Witness Alan L. Welte's testimony regarding Lewis & Clark Reciprocating Internal Combustion Engine (RICE) Project?

A. Yes. The Lewis & Clark RICE Project is comprised of two 9.3 MW (18.6 MW total capacity) Wartsilla 20V34SG units located at the existing Lewis & Clark plant, in Richland County, Montana. The RICE Project was placed in service in 2015 (commercial operation in April 2016) to mitigate reliability concerns in the Bakken Oil Field region areas of northwestern North Dakota and northeastern Montana, a problem identified in MDU's 2013 Integrated Resource Plan (IRP). The 2103 IRP was finalized in September of 2013. The total project cost was $47.19 million or $2,537/kW.

Q. What was the projected size and cost of this project in the 2013 IRP?

A. The 2013 IRP projected the installation of 36.6 MW at a cost of $34.95 million or $955/kW. The 2015 IRP included a revised reciprocating internal combustion engine ("RICE") project of 27.9 MW at a total cost of $47.62 million or $1,707/kW.

Q. What was the justification for the significantly higher project costs?

A. Mr. Welte states that MDU was required to "fast track" the project because the Basin Electric transmission system in the Bakken Region was unable to support the rapidly increasing load. This created the risk of power interruptions to MDU customers in the winter of 2015-2016. The fast track project development was the result of MDU not beginning project development until May 29, 2014, over eight (8) months after publishing the 2013 IRP. It is likely MDU was aware of this problem much sooner than the publishing of the 2013 IRP, since they would have had to study various options for addressing the potential power supply shortage in the 2013 IRP final edition.

Q. Have you compared the costs of MDU's RICE Project to similar power generation projects?

A. Yes. GDS has worked on many different power generation projects over the last several years and tracked the generation costs for various types of generation. In addition, multiple utilities have published IRP's which provide cost estimates for various types of power generation systems. The comparison of the costs of similar size generation projects is shown in Exhibit PSC-7. As can be seen in the table, the RICE Project was the most expensive, on $/kW basis, of all the projects in the list. As a comparison, MDU's Heskett III, 88 MW combustion turbine project's cost was only about $6 million higher than the RICE Project, while its generating capacity is over 4.7 times larger than the RICE Project.

Q. What is the typical cost range for a power generation project of similar size to the Rice Project on a $/kW basis?

A. The typical cost for a reciprocating internal combustion engine ("Recip") project in the size range of Lewis & Clark would be about $1,200/kW with an upper range of $1,500/kW for a greenfield site. For an existing site with existing infrastructure, the cost should be closer to $1,200/kW.

Q. What about MDU's claim they had to construct the project on an expedited schedule?

A. First, a typical construction schedule for a Recip project from initiation of engineering to commercial operation date is 24 to 30 months. The 19-month schedule for Lewis & Clark RICE was not significantly shorter. In fact, if you include the time to the commercial operation date of April 30, 2016, the schedule was a 23-month schedule. If MDU had begun the preliminary engineering and procurement of major components upon identification of need in the 2013 IRP (September 2013), then MDU would have had 27 months or more to complete the project prior to the winter of 2015-2016.

Second, MDU also had the option of renting generation to get through the winter of 2015-2016. Several companies rent small packaged combustion turbine or Recip generator systems. In preparation for this testimony I obtained a quote to rent three Taurus 60 gas turbines for a total output of 16.5 MW at a monthly rental rate of approximately $404,331/month on a six-month contract. The total cost would have been $2.426 million for rental of the units over the Winter of 2015-2016. Assuming a non-expedited cost of $1,500/kW the RICE Project would have cost MDU $27.9 million, a savings of $19.3 million, more than enough to pay for rental of the combustion turbines. Even if you use MDU's 2015 projected RICE Project cost of $1,707/kW the RICE Project would have cost $31.75 million, MDU would have saved over $13.7 million, *including paying the cost of the rental units.*

Q. What is your recommendation regarding incorporation of the Lewis & Clark RICE Project into North Dakota rate base?

A. I recommend that the Commission disallow a total of $17 million of the Lewis & Clark RICE Project. This disallowance is based upon an appropriate installed cost of $1,490 for an appropriate Recip project on an existing power plant site and includes the rental cost for temporary generation. The calculation off the recommended disallowance, as shown in **Table 2**, will reduce MDU's plant in service by $12,273,406. I believe this is a reasonable disallowance in that it does not take into consideration the cost savings of building the project on an existing power plant site. This disallowance has been reflected in revised Exhibit PSC-3.

Table 2 - RICE Project Disallowance

Lewis & Clark RICE Project		**$47,194,515**
Typical Small Generation Cost/kW	$1,490	
Smart Power Proejct Size - kW	18,600	
Typical Project Costs	**$27,714,000**	**$27,714,000**
Cost of Rental Unit		**$2,425,986**
Excess Smart Power Project Cost		**$17,054,529**
Round Down Disallowance		**$17,000,000**
North Dakota Allocation Factor		72.196505%
North Dakota Disallowance		**$12,273,406**

Revenue Requirement Calculation

Q. Have you performed a revenue requirement calculation based upon your adjustments?

A. Yes. Exhibit PSC-3 shows the calculation of MDU's revenue deficiency's/(sufficiency's) for Base Rates, the Renewable Rider and Transmission Cost Adjustment.

Q. What test period did you use to determine the revenue requirement?

A. My adjustments and calculations of the plant in service and revenue requirements were based upon year end 2016 and project 2017 supplied in Discovery Response 1.1. This represents the most recent year end costs and 2017 projections for MDU.

Q. What changes did you make in MDU's Plant in Service?

A. The following adjustments were made to MDU's plant in service:

1. Lewis & Clark RICE Project costs were reduced by $12,273,406 to reflect the recommended disallowance.
2. Removal of the provision for funding of future decommissioning costs.
3. Removed the losses on sale of manufactured homes.

Q. How did these items affect revenue requirements?

A. Reduction in rate base results in lowering gross income which affects income taxes. These impacts are shown on the revised Statement I. Disallowances for the RICE Project, elimination of the decommissioning funding and loss on manufactured housing affected depreciation and amortization amounts. All of these impacts are summarized in Exhibit PSC-3, which shows the recommended incremental revenue for MDU Base Rates is reduced to $515,316.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF NORTH DAKOTA

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Application of
MONTANA-DAKOTA UTILITIES CO.,
A Division of MDU Resources Group, Inc.
for authority to Increase Rates for Electric Service in North Dakota

Case No. PU-16-666

AFFIDAVIT OF
Richard A. Polich

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

Richard A. Polich

Subscribed and sworn to before me
this 24th day of February, 2017.

SEAL

K. RUDITYS
MY COMMISSION EXPIRES
NOTARY
PUBLIC
FEBRUARY 10, 2019
COBB COUNTY, GEORGIA

Notary Public

GDS Associates, Inc
ENGINEERS & CONSULTANTS

Richard A. Polich, P.E.
Managing Director – Generation Services

EDUCATION

Master of Business Administration, University of Michigan, 1990
Bachelor of Science, Mechanical Engineering, University of Michigan, 1979
Bachelor of Science, Nuclear Engineering, University of Michigan, 1979

ENGINEERING REGISTRATION

Professional Engineer in the State of Michigan

PROFESSIONAL MEMBERSHIP

National Society of Professional Engineers
American Nuclear Society
American Society of Mechanical Engineers
Association of Energy Engineers Senior Member

PROFESSIONAL EXPERIENCE

Mr. Polich has more than 30 years' experience as an energy industry engineer, manager, and leader, combining his business and technical expertise in the management of governmental, industrial and utility projects. He has worked extensively in nuclear, coal, IGCC, natural gas, green/renewable generation. Mr. Polich has developed generation projects in wind, solar, and biomass in Australia, Canada, Caribbean, South American and United States. His generation experience includes engineering of systems and providing engineering support of plant operations. He also has extensive experience in utility rates and regulation, having managed Consumers Energy's rates group for a number of years. In that function his responsibilities included load and revenue forecasting, overseeing the design of gas and electric rates and testifying in regulatory proceedings. Mr. Polich has testified in over thirty regulatory and legislative proceedings.

Mr. Polich has testified in over 30 regulatory proceedings on a variety of issues. Recently, Mr. Polich provided direct and rebuttal testimony before the Hawaii Public Utilities Commission in Docket No. 2015-0022, regarding the Hawaiian Electric Company, Inc. and NextEra Merger. Over 15 years' experience working with Michigan Public Service Commission on renewable energy policies, independent power supplier regulations, and electric rate cases. He has also worked with the Michigan Legislature: defined laws for open markets, renewable portfolio standards. Mr. Polich has worked on various projects and policies in Arizona, Arkansas, California, Georgia, Indiana, Minnesota Nebraska, New Mexico, Ohio, Texas, and Wisconsin Commissions over the last ten years.

SPECIFIC PROJECT EXPERIENCE

RATES & REGULATORY

GDS associates, Inc. – Managing Director

SunEdison – Docket No. 2015-0022, regarding the Hawaiian Electric Company, Inc. and NextEra Merger

Presented evidence regarding NextEra's regulatory practices in Florida through its affiliate, Florida Power and Light (FPL), that indicated it would not be in the best interest for Hawai'i to approve the merger.

North Dakota Public Service Commission Staff – Case No. PU-15-96 NSP Determination of Prudence

Provided testimony on behalf of the North Dakota Public Service Commission Staff regarding analysis and recommendation concerning Northern States Power's ("NSP") need for additional generation resources.

Consumers Energy - Supervisor of Pricing and Forecasting

Managed the group responsible for setting and obtaining regulatory approval for the company's electric and gas rates. Developed new approaches to electric and natural gas competitive pricing, redesigned electric rates to simplify rates and eliminate losses and defined new strategies for customer energy pricing. Negotiated new electric supply contracts with key industrial electric customers resulting in over $800M in annual revenue.

EOS Energy Options & Solutions – Consulting Company

Provided testimony for multiple clients in both Detroit Edison and Consumers Energy in over 30 regulatory proceedings. Testimony topics included rates, public policy and deregulation. Also testified in several legislative proceedings in both Michigan and Ohio, addressing energy policy. Provided expert witness testimony in Massachusetts regarding wind energy projects.

NATURAL GAS COMBINED CYCLE EXPERIENCE

Consumers Energy – 1,560 MW Midland Cogeneration Venture
Member of a small team selected to investigate the feasibility of converting the mothballed Midland Nuclear Plant into a fossil fueled power plant. Established new plant configuration that repowered the existing nuclear steam turbine with natural gas fired combustion turbines and heat recovery steam generators. Developed the new thermal cycle and heat rate, determined how to supply steam to Dow chemical for cogeneration, developed models for projecting plant performance, defined which portions of the nuclear plant were useful in the new combined cycle plant and forecasted project economics.

Nordic Energy – (2) 1,150 MW IGCC Projects

Project Manager for the development of two IGCC projects proposed to Georgia Power and Xcel Energy in response to RFPs. Responsibilities included establishing thermal cycles, equipment selection, site selection, supervising engineering, developing project proforma and proposals.

Nordic Energy – 230 MW Power Barge

This unit was to be located on the Columbia River near Portland Oregon. Lead the project development team responsible for securing equipment, designing the power plant, design of barges, assessing site feasibility, developing project economics and interconnection applications.

Teekay Corporation – Gas to Wires Project

Feasibility study for the development of ship mounted gas turbine power units (including combined cycle) to be fueled with LNG. Performed research into power station configuration, on-ship LNG storage, LNG fuel transfer stations and project economics.

GDS Associates, Inc
ENGINEERS & CONSULTANTS

Richard A. Polich, P.E.
Managing Director – Generation Services

RENEWABLE ENERGY EXPERIENCE

Matinee Energy – Utility Scale Solar Developer

Engineering design and project development consultant for utility scale solar photovoltaic projects. Development activities include site selection, equipment specifications, financial analysis and preparation of proposals. Also responsible for engineering and securing electrical interconnection.

Windlab Developments USA – Wind Power Developer

Responsible for greenfield development of the US platform for wind energy projects east of the Mississippi. Developed the company's engineering protocol for wind project design and construction, responsible for managing engineering design and construction of projects, and established six wind power projects (750 MW). Responsible for negation of Power Purchase Agreements, electrical interconnection studies, interface with Midwest ISO and submitting Generation Interconnection Application.

TradeWind Energy - Wind Power Project Developer

Project developer for 800 MW of wind power projects in Michigan and Indiana. Introduced new project management methods to the development process which resulted in savings of over $200,000 annually on each project.

Third Planet Windpower – Wind Power Project Developer

Engineering and project management consultant to support the startup of new wind power company. Established engineering standards used for selection of wind project equipment and project construction, analysis tools for evaluating projecting wind project power production, and performed project economic modeling.

Noble Environmental Power – Wind Power Project Developer

Electric transmission system consultant on the development of several wind power projects. Supported Noble's decisions on transmission gird interconnect and negotiate interconnection agreements.

ENERGY EFFICIENCY EXPERIENCE

Arkansas Energy Office – Weatherization Assistance Program Evaluation

Evaluated the performance and operations of Arkansas's Weatherization Assistance Program. This included review of program effectiveness, program operations, energy efficiencies attained, adequacy of energy efficiency measures and subcontractor performance.

CLEAResult – Arkansas Energy Efficiency Programs

Energy efficiency operations and program support for 400% increase in Arkansas energy efficiency programs. Developed processes for data collection, field staff deployment and job assignments.

ECONOMIC IMPACT ASSESSMENT

Michigan Department of Environmental Quality - Economic Impacts of a Renewable Portfolio Standard and Energy Efficiency Program for Michigan

Project Manager for this report which focused on the economic impact of renewable portfolio standard and energy efficiency programs on the State of Michigan. The evaluation sued in this report encompassed using integrated resource planning models, econometric modeling and electric pricing models for the entire State of Michigan.

West Michigan Business Alliance - Alternative and Renewable Energy Cluster Analysis

Prepared the report provided a road map for Western Michigan businesses to establish new business in the renewable energy industry.

POWER PURCHASING AND TRADING

Nordic Energy LLC - Vice President

Established an innovative energy trading floor, created customer metering and billing systems that enabled Nordic to be the first non-utility company to supply electricity to retail customers in Michigan.

POWER PROJECT EXPERIENCE:

Detroit Edison St Clair Power Station – Performed coal combustion analysis associated with conversion Powder River Basin coal. Work included pulverizer mill performance testing, boiler combustion analysis on new coal, and unit performance analysis.

Consumers Energy Campbell 3 - Supported start-up efforts of this 800 MW pulverized coal power plant. Part of team that performed analysis of boiler data and determined the cause of superheater failure. Also part of team to analyze performance test data for warranty evaluation.

Consumers Energy Weadock Plant – Design oversight and specified various plant upgrades during major maintenance outage. Included replacement of high pressure superheater, design of new steam supply pipes, valve specifications and supported plant restart.

Consumers Energy Midland Nuclear Plant – Responsible for overseeing EPC contractor design and construction of primary and secondary nuclear systems. Included review of systems for compliance with Nuclear Regulatory Commission regulations. Key projects included:

- Leading team to analyze plant and determine best methods for compliance with new CFR Appendix R Fire Protection rules
- Design of primary cooling system pump oil collection and disposal systems.
- Oversight of redesign of component cooling water systems.
- Analysis of diesel generator capability to meet emergency shutdown power requirements.
- Primary interface with Dow Chemical for steam supply contract.

Consumers Energy Midland Cogeneration Venture – Part of team to assess and develop design for converting nuclear plant to gas combined cycle project. This included researching and developing scenarios for project funding and regulatory approach Primary responsibilities included:

- Developing new thermal cycle that best utilized existing steam turbine and supply steam to Dow Chemical.
- Determining which existing assets could be utilized in new plant and determining the original construction value of these assets.

REGULATORY AND LEGISLATIVE EXPERIENCE

Consumers Energy Manager of Rates – Responsible for managing rate design team, forecasting annual sales and revenue forecast and developing regulatory strategies. Testified in several state and federal regulatory proceedings.

PAPERS & PUBLICATIONS

Engineering and Economic Evaluation of Offshore Wind Plant Performance and Cost Data, 2011, Produced for the Electric Power Research Institute, KEMA, Inc.

FERC's 15% Fast Track Screening Criterion, 2012, Paper reviewing the FERC 15% screening criteria for electrical interconnection, KEMA, Inc.

Island of Saint Maarten Sustainable Energy Study, 2012, Produced for the Cabinet of Ministry VROMI, KEMA Inc.

A Study of Economic Impacts from the Implementation of a Renewable Portfolio Standard and an Energy Efficiency Program in Michigan, 2007, Produced for the Michigan Department of Environmental Quality

Alternative and Renewable Energy Cluster Analysis, 2007, Produced for the West Michigan Strategic Alliance and The Right Place

COURSES & SEMINARS

Association of Energy Engineers – Certified Energy Manager
Green Building Council – Associated LEED Certification Training
CLEAResult Leadership Academy

COMMUNITY SERVICE AND ACTIVITIES

Bicycling, hiking and cross-country skiing
Instrument-Rated Private Pilot
Habitat for Humanity
Scoutmaster
Soccer coach and referee
Volunteer work for disaster relief and building homes in Mexico

Docket No. PU-16-666
Witness: Richard A Polich
Date: February 24, 2017
Exhibit No.: PSC-2
Page: 1 of 1

PREVIOUS TESTIMONY OF RICHARD A. POLICH

CASE	ON BEHALF	TITLE
2015-0022	Sun Edison	Regarding the Hawaiian Electric Company, Inc. and NextEra Merger
PU-15-96	ND PSC Staff	Northern States Power Determination of Prudence
U-10143	Consumers Energy	Consumers Energy Approval of an Experimental Retail Wheeling Case
U-10335	Consumers Energy	General Rate Case
U-10625	Consumers Energy	Proposal for Market-Based Rates Under Rate-K
U-10685	Consumers Energy	1996 General Rate Case
U-11915	Energy Michigan	Supplier Licensing
U-11955	Energy Michigan	Consumers Energy Stranded & Implementation Cost Recovery
U-11956	Energy Michigan	Detroit Edison Stranded & Implementation Cost Recovery
U-12478	Energy Michigan	Detroit Edison Asset Securitization Case
U-12488	Energy Michigan	Consumers Energy Retail Open Access Tariff
U-12489	Energy Michigan	Detroit Edison Retail Open Access Tariffs
U-12505	Energy Michigan	Consumers Energy Asset Securitization Cases
U-12639	Energy Michigan	Stranded Cost Methodology Case
U-13380	Energy Michigan	Consumers Energy 2000, 2001 & 2002 Stranded Cost Case
U-13350	Energy Michigan	Detroit Edison 2000 & 2001 Stranded Cost Case
U-13715	Energy Michigan	Consumers Energy Securitization of Qualified Costs
U-13720	Energy Michigan	Consumers Energy 2002 Stranded Costs
U-13808	Energy Michigan	Detroit Edison General Rate Case
U-13808-R	Energy Michigan	Detroit Edison 2004 Stranded Cost &
U-14474	Energy Michigan	Detroit Edison 2004 PSCR Reconciliation Case
U-13933	Energy Michigan	Detroit Edison Low-Income Energy Assistance Credit for Residential Electric Customers
U-13917-R	Energy Michigan	Consumers Energy 2004 PSCR Reconciliation Case
U-13989	Energy Michigan	Consumers Energy Request for Special Contract Approval
U-14098	Energy Michigan	Consumers Energy 2003 Stranded Costs
U-14148	Energy Michigan	Consumers Energy MCL 460.10d(4) Case
U-14347	Energy Michigan	Consumers Energy General Rate Case
U-14274-R	Energy Michigan	Consumers Energy 2005 PSCR Reconciliation Case
U-14275-R	Energy Michigan	Detroit Edison Company 2005 PSCR Reconciliation Case
U-14399	Energy Michigan	Detroit Edison Company Application for Unbundling of Rate
U-14992	Energy Michigan	Power Purchase Agreement and for Other Relief in Connection with the sale of the Palisades Nuclear Power Plant and Other Assets

Case No.:	PU-16-666
Witness:	RA Polich
Date:	24-Feb-17
Exhibit No.	PSC - 3
Page:	1 of 3

MONTANA-DAKOTA UTILITIES CO
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2017

	Before Additional Revenue Requirements	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$182,637,355	**$515,316**		$183,152,671
Sales for Resale	-			-
Other	3,671,067			3,671,067
Total Revenues	186,308,422	515,316		186,823,738
Operating Expenses				
Operation and Maintenance				
Cost of Fuel & Purchased Power	54,190,975			54,190,975
Other O&M	52,325,778			52,325,778
Total O&M	106,516,753			106,516,753
Depreciation	24,745,704			24,745,704
Taxes Other Than Income	6,391,931			6,391,931
Current Income Taxes	13,656,204	194,797	1/	13,851,001
Deferred Income Taxes	0			0
Total Expenses	151,310,592	194,797		151,505,389
Operating Income	$34,997,830	$320,519		$35,318,349
Rate Base	$520,229,030			$520,229,030
Rate of Return	**6.727%**			**6.789%**
Return on Equity				8.531%

1/ Reflects state and federal taxes at 37.8015%.

Case No.:	PU-16-666
Witness:	RA Polich
Date:	24-Feb-17
Exhibit No.	PSC - 3
Page:	2 of 3

MONTANA-DAKOTA UTILITIES CO
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2017

WIND - RENEWABLE RIDER

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$13,923,093	**($1,775,588)**	$12,147,505
Operating Expenses			
Operation and Maintenance			
Cost of Fuel & Purchased Power	0		0
Other O&M	2,102,989		2,102,989
Total O&M	2,102,989		2,102,989
Depreciation	9,231,971		9,231,971
Taxes Other Than Income	634,247		634,247
Current Income Taxes	(9,906,094)	(671,199) 2/	(10,577,293)
Deferred Income Taxes	0		0
Total Expenses	2,063,113	(671,199)	1,391,914
Operating Income	$11,859,980	($1,104,389)	$10,755,591
Rate Base	$158,426,734		$158,426,734
Rate of Return	**7.486%**		**6.789%**

1/ Reflects state and federal taxes at 37.8015%.

Case No.:	PU-16-666
Witness:	RA Polich
Date:	24-Feb-17
Exhibit No.	PSC - 3
Page:	3 of 3

MONTANA-DAKOTA UTILITIES CO
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2017

TRANSMISSION COST ADJUSTMENT

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$6,183,536	**($674,367)**	$5,509,169
Other	14,473,223		14,473,223
Total Revenues	20,656,759		19,982,392
Operating Expenses			
Operation and Maintenance			
Cost of Fuel & Purchased Power	0		0
Other O&M	19,982,392		19,982,392
Total O&M	19,982,392		19,982,392
Depreciation	0		0
Taxes Other Than Income	0		0
Current Income Taxes	0		0
Deferred Income Taxes	0		0
Total Expenses	19,982,392	0	19,982,392
Operating Income	$674,367	$0	$0

MDU Resources Group, Inc.
NDPSC Case No. PU-16-666

National Electric Utility Proxy Group DCF Analysis Using Two-Step Growth DCF Methodology
Value Line Electrics with S&P CCR of BBB to A-
Using Data for the Six Months Ending January 2017

Line No.	Company (a)	Ticker (b)	Standard & Poor's Corporate Credit Rating (c)	Moody's Long Term Issuer or Sr Unsecured Rating (d)	Value Line Safety Rank (e)	Six Month Average Dividend Yld (f)	IBES Analysts' Proj EPS g (g)	Long-term GDP Growth Rate (h)	Composite Growth Rate (i)	Adjusted Dividend Yield (j)	DCF ROE Ke (k)	Price to Book Value (l)
1	ALLETE	ALE	BBB+	A3	2	3.38%	5.00%	4.35%	4.78%	3.47%	8.25%	1.62
2	Alliant Energy	LNT	A-	Baa1	2	3.12%	6.00%	4.35%	5.45%	3.20%	8.65%	2.09
3	Amer. Elec. Power	AEP	A-	Baa1	2	3.63%	1.49%	4.35%	2.44%	3.68%	6.12%	1.80
4	Ameren Corp.	AEE	BBB+	Baa1	2	3.42%	5.85%	4.35%	5.35%	3.52%	8.87%	1.70
5	Avista Corp.	AVA	BBB	Baa1	2	3.36%	5.65%	4.35%	5.22%	3.45%	8.67%	1.60
6	Black Hills Corp.	BKH	BBB	Baa2	2	2.80%	8.39%	4.35%	7.04%	2.90%	9.94%	1.99
7	CMS Energy	CMS	BBB+	Baa2	2	2.97%	7.26%	4.35%	6.29%	3.06%	9.35%	2.78
8	Consol. Edison	ED	A-	A3	1	3.62%	2.02%	4.35%	2.80%	3.67%	6.47%	1.58
9	DTE Energy	DTE	BBB+	Baa1	2	3.29%	5.51%	4.35%	5.12%	3.37%	8.50%	1.88
10	Edison Int'l	EIX	BBB+	A3	2	2.72%	1.92%	4.35%	2.73%	2.76%	5.49%	1.96
11	El Paso Electric	EE	BBB	Baa1	2	2.70%	6.50%	4.35%	5.78%	2.78%	8.56%	1.76
12	Entergy Corp.	ETR	BBB+	Baa3	3	4.65%	-8.19%	4.35%	-4.01%	4.56%	0.55%	1.38
13	Exelon Corp.	EXC	BBB	Baa2	3	3.74%	5.95%	4.35%	5.42%	3.85%	9.26%	1.22
14	IDACORP, Inc.	IDA	BBB	Baa1	2	2.72%	4.10%	4.35%	4.18%	2.78%	6.96%	1.82
15	NorthWestern Corp.	NWE	BBB	A3	3	3.50%	4.34%	4.35%	4.34%	3.57%	7.92%	1.66
16	OGE Energy Corp.	OGE	A-	A3	2	3.70%	4.00%	4.35%	4.12%	3.77%	7.89%	1.84
17	Otter Tail Corp.	OTTR	BBB	NR	2	3.43%	6.00%	4.35%	5.45%	3.52%	8.97%	2.12
18	PG&E Corp.	PCG	BBB+	Baa1	3	3.21%	5.67%	4.35%	5.23%	3.29%	8.52%	1.74
19	Pinnacle West	PNW	A-	A3	1	3.37%	5.30%	4.35%	4.98%	3.46%	8.44%	1.78
20	PNM Resources, Inc.	PNM	BBB+	Baa3	3	2.68%	6.85%	4.35%	6.02%	2.76%	8.78%	1.45
21	Portland General	POR	BBB	A3	2	3.00%	6.60%	4.35%	5.85%	3.08%	8.93%	1.63
22	PPL Corp.	PPL	A-	Baa2	2	4.43%	2.44%	4.35%	3.08%	4.50%	7.58%	2.36
23	Public Serv. Enterprise	PEG	BBB+	Baa2	1	3.85%	1.17%	4.35%	2.23%	3.90%	6.13%	1.64
24	SCANA Corp.	SCG	BBB+	Baa3	2	3.21%	5.70%	4.35%	5.25%	3.30%	8.55%	1.80
25	Sempra Energy	SRE	BBB+	Baa1	2	2.91%	6.50%	4.35%	5.78%	2.99%	8.78%	2.10
26	Southern Co.	SO	A-	Baa2	2	4.47%	3.14%	4.35%	3.54%	4.55%	8.09%	1.75
27	Vectren Corp.	VVC	A-	NR	2	3.26%	4.57%	4.35%	4.50%	3.33%	7.83%	2.34
28	WEC Energy Group	WEC	A-	A3	1	3.36%	6.73%	4.35%	5.94%	3.46%	9.40%	2.09
29	Xcel Energy	XEL	A-	A3	1	3.33%	5.65%	4.35%	5.22%	3.42%	8.63%	1.88
30	Average				2.0	3.37%	4.56%	4.35%	4.49%	3.45%	7.93%	1.84
31	Low - 29 Companies										0.55%	
32	High - 29 Companies										9.94%	
33	Median										8.52%	
34	True 75th Percentile Value										8.78%	
35	Midpoint of the Top Half of the Array										7.59%	
	<u>After Adjustment To Remove ETR</u>											
36	Low - 28 Companies										5.49%	
37	High - 28 Companies										9.94%	
38	**Median and Recommended ROE for MDU**										8.53%	
39	True 75th Percentile Value										8.80%	
40	Midpoint of the Top Half of the Array										8.83%	
36	MDU Resources Group	MDU	BBB+									

Notes:

(f) - Avg. of the monthly low and high dividend yields for the 6 months ending Jan. 31, 2017. (pp. 2-6)
(g) - Thomson Reuters/IBES reported consensus of analysts' projected "5-year" earnings per share growth rate from Yahoo! Finance as of January 31, 2017. Xcel growth rate from Reuters.
(h) - Average long-term GDP growth rate.
(i) - Composite avg. growth rate with IBES and GDP growth rates weighted 2/3 and 1/3, respectively.
(j) - Dividend yield times (1 + 0.5g), where g = composite average growth rate.
(k) - ROE equals the adjusted dividend yield plus the composite average growth rate.
(l) - Price to book values calculated using August 2016 - January 2017 average market price and Value Line reported year end 2016 book values. (p. 7)

<u>Moody's Public Utility Bond Index Yields</u>

<u>Aug 2016 - Jan 2017</u>		<u>Threshold</u>
A Bond Avg Yield:	3.94%	4.94%
Baa Bond Avg Yield:	4.51%	5.51%
Average	4.22%	5.22%

MDU Resources Group, Inc.
NDPSC Case No. PU-16-666

SIX MONTH AVERAGE DIVIDEND YIELD

	Price				Dividend Yield		
	High	Low	Avg	Div	Low	High	Avg
ALLETE							
Jan-17	$ 65.48	$ 61.64	$ 63.56	$ 2.080	3.18%	3.37%	3.27%
Dec-16	$ 66.92	$ 60.97	$ 63.94	$ 2.080	3.11%	3.41%	3.25%
Nov-16	$ 64.57	$ 56.48	$ 60.53	$ 2.080	3.22%	3.68%	3.44%
Oct-16	$ 61.40	$ 56.57	$ 58.99	$ 2.080	3.39%	3.68%	3.53%
Sep-16	$ 62.70	$ 58.20	$ 60.45	$ 2.080	3.32%	3.57%	3.44%
Aug-16	$ 64.46	$ 58.60	$ 61.53	$ 2.080	3.23%	3.55%	3.38%
Average	$ 64.26	$ 58.74	**$ 61.50**		**3.24%**	**3.54%**	**3.38%**
Alliant Energy							
Jan-17	$ 38.29	$ 36.56	$ 37.43	$ 1.176	3.07%	3.22%	3.14%
Dec-16	$ 38.34	$ 35.26	$ 36.80	$ 1.176	3.07%	3.34%	3.20%
Nov-16	$ 38.67	$ 34.88	$ 36.77	$ 1.176	3.04%	3.37%	3.20%
Oct-16	$ 38.33	$ 36.31	$ 37.32	$ 1.176	3.07%	3.24%	3.15%
Sep-16	$ 40.60	$ 37.09	$ 38.84	$ 1.176	2.90%	3.17%	3.03%
Aug-16	$ 40.58	$ 37.69	$ 39.14	$ 1.176	2.90%	3.12%	3.00%
Average	$ 39.14	$ 36.30	**$ 37.72**		**3.01%**	**3.24%**	**3.12%**
Amer. Elec. Power							
Jan-17	$ 64.11	$ 61.82	$ 62.97	$ 2.360	3.68%	3.82%	3.75%
Dec-16	$ 63.53	$ 57.89	$ 60.71	$ 2.360	3.71%	4.08%	3.89%
Nov-16	$ 64.90	$ 58.16	$ 61.53	$ 2.360	3.64%	4.06%	3.84%
Oct-16	$ 65.25	$ 61.28	$ 63.26	$ 2.240	3.43%	3.66%	3.54%
Sep-16	$ 66.96	$ 63.56	$ 65.26	$ 2.240	3.35%	3.52%	3.43%
Aug-16	$ 69.48	$ 64.07	$ 66.78	$ 2.240	3.22%	3.50%	3.35%
Average	$ 65.71	$ 61.13	**$ 63.42**		**3.51%**	**3.77%**	**3.63%**
Ameren Corp.							
Jan-17	$ 53.40	$ 51.35	$ 52.38	$ 1.760	3.30%	3.43%	3.36%
Dec-16	$ 52.88	$ 48.32	$ 50.60	$ 1.760	3.33%	3.64%	3.48%
Nov-16	$ 51.46	$ 46.97	$ 49.22	$ 1.700	3.30%	3.62%	3.45%
Oct-16	$ 50.25	$ 46.84	$ 48.55	$ 1.700	3.38%	3.63%	3.50%
Sep-16	$ 51.91	$ 47.79	$ 49.85	$ 1.700	3.27%	3.56%	3.41%
Aug-16	$ 52.59	$ 49.15	$ 50.87	$ 1.700	3.23%	3.46%	3.34%
Average	$ 52.08	$ 48.40	**$ 50.24**		**3.30%**	**3.56%**	**3.42%**
Avista Corp.							
Jan-17	$ 40.17	$ 37.88	$ 39.02	$ 1.372	3.42%	3.62%	3.52%
Dec-16	$ 43.00	$ 38.69	$ 40.84	$ 1.372	3.19%	3.55%	3.36%
Nov-16	$ 42.26	$ 39.21	$ 40.73	$ 1.372	3.25%	3.50%	3.37%
Oct-16	$ 41.74	$ 38.99	$ 40.37	$ 1.372	3.29%	3.52%	3.40%
Sep-16	$ 43.74	$ 40.38	$ 42.06	$ 1.372	3.14%	3.40%	3.26%
Aug-16	$ 43.71	$ 40.30	$ 42.00	$ 1.372	3.14%	3.40%	3.27%
Average	$ 42.44	$ 39.24	**$ 40.84**		**3.24%**	**3.50%**	**3.36%**
Black Hills Corp.							
Jan-17	$ 62.70	$ 60.02	$ 61.36	$ 1.680	2.68%	2.80%	2.74%
Dec-16	$ 62.83	$ 57.58	$ 60.21	$ 1.680	2.67%	2.92%	2.79%
Nov-16	$ 61.90	$ 54.76	$ 58.33	$ 1.680	2.71%	3.07%	2.88%
Oct-16	$ 62.07	$ 56.53	$ 59.30	$ 1.680	2.71%	2.97%	2.83%
Sep-16	$ 63.79	$ 57.51	$ 60.65	$ 1.680	2.63%	2.92%	2.77%
Aug-16	$ 63.87	$ 56.86	$ 60.37	$ 1.680	2.63%	2.95%	2.78%
Average	$ 62.86	$ 57.21	**$ 60.04**		**2.67%**	**2.94%**	**2.80%**

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CMS Energy							
Jan-17	$ 42.61	$ 41.12	$ 41.87	$ 1.240	2.91%	3.02%	2.96%
Dec-16	$ 42.00	$ 39.42	$ 40.71	$ 1.240	2.95%	3.15%	3.05%
Nov-16	$ 42.27	$ 38.78	$ 40.52	$ 1.240	2.93%	3.20%	3.06%
Oct-16	$ 42.55	$ 40.01	$ 41.28	$ 1.240	2.91%	3.10%	3.00%
Sep-16	$ 44.44	$ 41.14	$ 42.79	$ 1.240	2.79%	3.01%	2.90%
Aug-16	$ 45.37	$ 41.49	$ 43.43	$ 1.240	2.73%	2.99%	2.86%
Average	$ 43.21	$ 40.33	**$ 41.77**		**2.87%**	**3.08%**	**2.97%**
Consol. Edison							
Jan-17	$ 74.83	$ 72.13	$ 73.48	$ 2.680	3.58%	3.72%	3.65%
Dec-16	$ 74.30	$ 68.85	$ 71.58	$ 2.680	3.61%	3.89%	3.74%
Nov-16	$ 75.62	$ 68.76	$ 72.19	$ 2.680	3.54%	3.90%	3.71%
Oct-16	$ 76.03	$ 71.35	$ 73.69	$ 2.680	3.52%	3.76%	3.64%
Sep-16	$ 79.54	$ 72.93	$ 76.24	$ 2.680	3.37%	3.67%	3.52%
Aug-16	$ 80.61	$ 74.09	$ 77.35	$ 2.680	3.32%	3.62%	3.46%
Average	$ 76.82	$ 71.35	**$ 74.09**		**3.49%**	**3.76%**	**3.62%**
DTE Energy							
Jan-17	$ 99.49	$ 96.58	$ 98.04	$ 3.300	3.32%	3.42%	3.37%
Dec-16	$ 99.92	$ 92.19	$ 96.06	$ 3.300	3.30%	3.58%	3.44%
Nov-16	$ 96.78	$ 89.66	$ 93.22	$ 3.080	3.18%	3.44%	3.30%
Oct-16	$ 96.54	$ 90.75	$ 93.65	$ 3.080	3.19%	3.39%	3.29%
Sep-16	$ 97.60	$ 90.61	$ 94.10	$ 3.080	3.16%	3.40%	3.27%
Aug-16	$ 98.44	$ 92.24	$ 95.34	$ 2.920	2.97%	3.17%	3.06%
Average	$ 98.13	$ 92.01	**$ 95.07**		**3.19%**	**3.40%**	**3.29%**
Edison Int'l							
Jan-17	$ 72.95	$ 70.57	$ 71.76	$ 2.172	2.98%	3.08%	3.03%
Dec-16	$ 72.62	$ 67.73	$ 70.18	$ 1.920	2.64%	2.83%	2.74%
Nov-16	$ 73.44	$ 67.44	$ 70.44	$ 1.920	2.61%	2.85%	2.73%
Oct-16	$ 73.81	$ 69.21	$ 71.51	$ 1.920	2.60%	2.77%	2.68%
Sep-16	$ 76.30	$ 71.31	$ 73.81	$ 1.920	2.52%	2.69%	2.60%
Aug-16	$ 77.40	$ 71.74	$ 74.57	$ 1.920	2.48%	2.68%	2.57%
Average	$ 74.42	$ 69.67	**$ 72.04**		**2.64%**	**2.82%**	**2.72%**
El Paso Electric							
Jan-17	$ 47.20	$ 44.70	$ 45.95	$ 1.240	2.63%	2.77%	2.70%
Dec-16	$ 48.35	$ 44.55	$ 46.45	$ 1.240	2.56%	2.78%	2.67%
Nov-16	$ 47.55	$ 43.55	$ 45.55	$ 1.240	2.61%	2.85%	2.72%
Oct-16	$ 47.00	$ 42.49	$ 44.75	$ 1.240	2.64%	2.92%	2.77%
Sep-16	$ 48.75	$ 44.07	$ 46.41	$ 1.240	2.54%	2.81%	2.67%
Aug-16	$ 47.82	$ 44.82	$ 46.32	$ 1.240	2.59%	2.77%	2.68%
Average	$ 47.78	$ 44.03	**$ 45.90**		**2.60%**	**2.82%**	**2.70%**
Entergy Corp.							
Jan-17	$ 73.89	$ 70.02	$ 71.95	$ 3.480	4.71%	4.97%	4.84%
Dec-16	$ 73.79	$ 67.84	$ 70.81	$ 3.480	4.72%	5.13%	4.91%
Nov-16	$ 73.71	$ 66.71	$ 70.21	$ 3.480	4.72%	5.22%	4.96%
Oct-16	$ 76.56	$ 70.90	$ 73.73	$ 3.400	4.44%	4.80%	4.61%
Sep-16	$ 81.83	$ 75.99	$ 78.91	$ 3.400	4.15%	4.47%	4.31%
Aug-16	$ 82.00	$ 76.60	$ 79.30	$ 3.400	4.15%	4.44%	4.29%
Average	$ 76.96	$ 71.34	**$ 74.15**		**4.48%**	**4.84%**	**4.65%**

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Exelon Corp.								
Jan-17	$ 36.21	$ 34.80	$	35.50	$ 1.272	3.51%	3.66%	3.58%
Dec-16	$ 36.36	$ 31.77	$	34.07	$ 1.272	3.50%	4.00%	3.73%
Nov-16	$ 34.06	$ 29.82	$	31.94	$ 1.272	3.73%	4.27%	3.98%
Oct-16	$ 34.13	$ 31.68	$	32.91	$ 1.272	3.73%	4.02%	3.87%
Sep-16	$ 35.27	$ 32.86	$	34.07	$ 1.272	3.61%	3.87%	3.73%
Aug-16	$ 37.70	$ 33.61	$	35.66	$ 1.272	3.37%	3.78%	3.57%
Average	$ 35.62	$ 32.42	**$**	**34.02**		**3.58%**	**3.93%**	**3.74%**
IDACORP, Inc.								
Jan-17	$ 81.14	$ 77.49	$	79.31	$ 2.200	2.71%	2.84%	2.77%
Dec-16	$ 81.81	$ 75.03	$	78.42	$ 2.200	2.69%	2.93%	2.81%
Nov-16	$ 79.43	$ 72.93	$	76.18	$ 2.200	2.77%	3.02%	2.89%
Oct-16	$ 78.86	$ 73.33	$	76.10	$ 2.040	2.59%	2.78%	2.68%
Sep-16	$ 81.55	$ 75.14	$	78.35	$ 2.040	2.50%	2.71%	2.60%
Aug-16	$ 81.71	$ 75.46	$	78.58	$ 2.040	2.50%	2.70%	2.60%
Average	$ 80.75	$ 74.90	**$**	**77.82**		**2.63%**	**2.83%**	**2.72%**
NorthWestern Corp.								
Jan-17	$ 57.88	$ 55.99	$	56.94	$ 2.000	3.46%	3.57%	3.51%
Dec-16	$ 58.08	$ 54.07	$	56.08	$ 2.000	3.44%	3.70%	3.57%
Nov-16	$ 59.13	$ 54.78	$	56.96	$ 2.000	3.38%	3.65%	3.51%
Oct-16	$ 57.76	$ 53.85	$	55.80	$ 2.000	3.46%	3.71%	3.58%
Sep-16	$ 60.71	$ 56.18	$	58.44	$ 2.000	3.29%	3.56%	3.42%
Aug-16	$ 61.32	$ 57.09	$	59.21	$ 2.000	3.26%	3.50%	3.38%
Average	$ 59.15	$ 55.33	**$**	**57.24**		**3.38%**	**3.62%**	**3.50%**
OGE Energy Corp.								
Jan-17	$ 34.16	$ 32.85	$	33.50	$ 1.212	3.55%	3.69%	3.62%
Dec-16	$ 34.23	$ 31.26	$	32.75	$ 1.212	3.54%	3.88%	3.70%
Nov-16	$ 32.48	$ 29.57	$	31.03	$ 1.212	3.73%	4.10%	3.91%
Oct-16	$ 31.69	$ 29.61	$	30.65	$ 1.212	3.82%	4.09%	3.95%
Sep-16	$ 33.10	$ 30.59	$	31.84	$ 1.100	3.32%	3.60%	3.45%
Aug-16	$ 32.29	$ 29.91	$	31.10	$ 1.100	3.41%	3.68%	3.54%
Average	$ 32.99	$ 30.63	**$**	**31.81**		**3.56%**	**3.84%**	**3.70%**
Otter Tail Corp.								
Jan-17	$ 40.80	$ 37.05	$	38.92	$ 1.252	3.07%	3.38%	3.22%
Dec-16	$ 42.55	$ 37.75	$	40.15	$ 1.252	2.94%	3.32%	3.12%
Nov-16	$ 39.75	$ 33.45	$	36.60	$ 1.252	3.15%	3.74%	3.42%
Oct-16	$ 36.50	$ 33.08	$	34.79	$ 1.252	3.43%	3.78%	3.60%
Sep-16	$ 36.42	$ 33.91	$	35.16	$ 1.252	3.44%	3.69%	3.56%
Aug-16	$ 35.42	$ 32.99	$	34.21	$ 1.252	3.53%	3.80%	3.66%
Average	$ 38.57	$ 34.71	**$**	**36.64**		**3.26%**	**3.62%**	**3.43%**
PG&E Corp.								
Jan-17	$ 61.91	$ 59.89	$	60.90	$ 1.960	3.17%	3.27%	3.22%
Dec-16	$ 61.54	$ 57.60	$	59.57	$ 1.960	3.18%	3.40%	3.29%
Nov-16	$ 62.23	$ 57.63	$	59.93	$ 1.960	3.15%	3.40%	3.27%
Oct-16	$ 62.69	$ 58.20	$	60.45	$ 1.960	3.13%	3.37%	3.24%
Sep-16	$ 64.40	$ 60.44	$	62.42	$ 1.960	3.04%	3.24%	3.14%
Aug-16	$ 65.39	$ 61.48	$	63.43	$ 1.960	3.00%	3.19%	3.09%
Average	$ 63.03	$ 59.21	**$**	**61.12**		**3.11%**	**3.31%**	**3.21%**

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Pinnacle West							
Jan-17	$ 78.80	$ 75.79	$ 77.30	$ 2.620	3.32%	3.46%	3.39%
Dec-16	$ 78.97	$ 72.61	$ 75.79	$ 2.620	3.32%	3.61%	3.46%
Nov-16	$ 77.34	$ 70.86	$ 74.10	$ 2.620	3.39%	3.70%	3.54%
Oct-16	$ 76.59	$ 72.07	$ 74.33	$ 2.500	3.26%	3.47%	3.36%
Sep-16	$ 80.19	$ 73.94	$ 77.07	$ 2.500	3.12%	3.38%	3.24%
Aug-16	$ 79.54	$ 74.28	$ 76.91	$ 2.500	3.14%	3.37%	3.25%
Average	$ 78.57	$ 73.26	**$ 75.92**		**3.26%**	**3.50%**	**3.37%**
PNM Resources, Inc.							
Jan-17	$ 34.75	$ 33.35	$ 34.05	$ 0.880	2.53%	2.64%	2.58%
Dec-16	$ 34.53	$ 31.00	$ 32.76	$ 0.880	2.55%	2.84%	2.69%
Nov-16	$ 33.45	$ 30.95	$ 32.20	$ 0.880	2.63%	2.84%	2.73%
Oct-16	$ 33.25	$ 30.98	$ 32.12	$ 0.880	2.65%	2.84%	2.74%
Sep-16	$ 34.91	$ 31.20	$ 33.06	$ 0.880	2.52%	2.82%	2.66%
Aug-16	$ 34.51	$ 31.56	$ 33.03	$ 0.880	2.55%	2.79%	2.66%
Average	$ 34.23	$ 31.51	**$ 32.87**		**2.57%**	**2.80%**	**2.68%**
Portland General							
Jan-17	$ 44.15	$ 42.61	$ 43.38	$ 1.280	2.90%	3.00%	2.95%
Dec-16	$ 44.14	$ 40.71	$ 42.42	$ 1.280	2.90%	3.14%	3.02%
Nov-16	$ 43.91	$ 40.87	$ 42.39	$ 1.280	2.92%	3.13%	3.02%
Oct-16	$ 44.32	$ 40.28	$ 42.30	$ 1.280	2.89%	3.18%	3.03%
Sep-16	$ 44.12	$ 41.71	$ 42.91	$ 1.280	2.90%	3.07%	2.98%
Aug-16	$ 44.46	$ 41.51	$ 42.98	$ 1.280	2.88%	3.08%	2.98%
Average	$ 44.18	$ 41.28	**$ 42.73**		**2.90%**	**3.10%**	**3.00%**
PPL Corp.							
Jan-17	$ 34.92	$ 33.72	$ 34.32	$ 1.520	4.35%	4.51%	4.43%
Dec-16	$ 34.90	$ 32.69	$ 33.80	$ 1.520	4.36%	4.65%	4.50%
Nov-16	$ 34.98	$ 32.46	$ 33.72	$ 1.520	4.35%	4.68%	4.51%
Oct-16	$ 34.57	$ 32.08	$ 33.33	$ 1.520	4.40%	4.74%	4.56%
Sep-16	$ 35.94	$ 33.52	$ 34.73	$ 1.520	4.23%	4.53%	4.38%
Aug-16	$ 37.76	$ 34.35	$ 36.05	$ 1.520	4.03%	4.43%	4.22%
Average	$ 35.51	$ 33.14	**$ 34.32**		**4.28%**	**4.59%**	**4.43%**
Public Serv. Enterprise							
Jan-17	$ 44.70	$ 42.86	$ 43.78	$ 1.640	3.67%	3.83%	3.75%
Dec-16	$ 44.29	$ 40.72	$ 42.51	$ 1.640	3.70%	4.03%	3.86%
Nov-16	$ 43.11	$ 39.28	$ 41.20	$ 1.640	3.80%	4.18%	3.98%
Oct-16	$ 42.25	$ 40.38	$ 41.32	$ 1.640	3.88%	4.06%	3.97%
Sep-16	$ 44.01	$ 41.07	$ 42.54	$ 1.640	3.73%	3.99%	3.86%
Aug-16	$ 46.10	$ 42.25	$ 44.17	$ 1.640	3.56%	3.88%	3.71%
Average	$ 44.08	$ 41.09	**$ 42.59**		**3.72%**	**3.99%**	**3.85%**
SCANA Corp.							
Jan-17	$ 74.06	$ 67.71	$ 70.88	$ 2.300	3.11%	3.40%	3.24%
Dec-16	$ 74.99	$ 69.71	$ 72.35	$ 2.300	3.07%	3.30%	3.18%
Nov-16	$ 73.52	$ 67.31	$ 70.41	$ 2.300	3.13%	3.42%	3.27%
Oct-16	$ 73.83	$ 67.91	$ 70.87	$ 2.300	3.12%	3.39%	3.25%
Sep-16	$ 75.92	$ 69.04	$ 72.48	$ 2.300	3.03%	3.33%	3.17%
Aug-16	$ 75.80	$ 69.83	$ 72.82	$ 2.300	3.03%	3.29%	3.16%
Average	$ 74.69	$ 68.59	**$ 71.64**		**3.08%**	**3.35%**	**3.21%**

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	Witness:	RA Polich		
	Date:	24-Feb-17		
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Sempra Energy							
Jan-17	$ 104.25	$ 99.71	$ 101.98	$ 3.020	2.90%	3.03%	2.96%
Dec-16	$ 104.70	$ 98.12	$ 101.41	$ 3.020	2.88%	3.08%	2.98%
Nov-16	$ 107.10	$ 92.95	$ 100.02	$ 3.020	2.82%	3.25%	3.02%
Oct-16	$ 109.42	$ 101.70	$ 105.56	$ 3.020	2.76%	2.97%	2.86%
Sep-16	$ 111.40	$ 102.15	$ 106.78	$ 3.020	2.71%	2.96%	2.83%
Aug-16	$ 111.96	$ 103.62	$ 107.79	$ 3.020	2.70%	2.91%	2.80%
Average	$ 108.14	$ 99.71	**$ 103.92**		**2.79%**	**3.03%**	**2.91%**
Southern Co.							
Jan-17	$ 49.85	$ 48.19	$ 49.02	$ 2.240	4.49%	4.65%	4.57%
Dec-16	$ 49.64	$ 46.20	$ 47.92	$ 2.240	4.51%	4.85%	4.67%
Nov-16	$ 51.68	$ 46.79	$ 49.24	$ 2.240	4.33%	4.79%	4.55%
Oct-16	$ 52.23	$ 49.14	$ 50.68	$ 2.240	4.29%	4.56%	4.42%
Sep-16	$ 53.73	$ 50.77	$ 52.25	$ 2.240	4.17%	4.41%	4.29%
Aug-16	$ 53.80	$ 50.00	$ 51.90	$ 2.240	4.16%	4.48%	4.32%
Average	$ 51.82	$ 48.52	**$ 50.17**		**4.33%**	**4.62%**	**4.47%**
Vectren Corp.							
Jan-17	$ 55.20	$ 51.50	$ 53.35	$ 1.680	3.04%	3.26%	3.15%
Dec-16	$ 53.05	$ 48.41	$ 50.73	$ 1.680	3.17%	3.47%	3.31%
Nov-16	$ 51.88	$ 46.52	$ 49.20	$ 1.680	3.24%	3.61%	3.41%
Oct-16	$ 50.34	$ 47.00	$ 48.67	$ 1.600	3.18%	3.40%	3.29%
Sep-16	$ 52.04	$ 47.87	$ 49.96	$ 1.600	3.07%	3.34%	3.20%
Aug-16	$ 52.47	$ 48.56	$ 50.52	$ 1.600	3.05%	3.29%	3.17%
Average	$ 52.50	$ 48.31	**$ 50.40**		**3.13%**	**3.40%**	**3.26%**
WEC Energy Group							
Jan-17	$ 59.63	$ 57.63	$ 58.63	$ 1.980	3.32%	3.44%	3.38%
Dec-16	$ 59.12	$ 54.96	$ 57.04	$ 1.980	3.35%	3.60%	3.47%
Nov-16	$ 59.74	$ 53.66	$ 56.70	$ 1.980	3.31%	3.69%	3.49%
Oct-16	$ 60.13	$ 56.46	$ 58.30	$ 1.980	3.29%	3.51%	3.40%
Sep-16	$ 63.35	$ 59.03	$ 61.19	$ 1.980	3.13%	3.35%	3.24%
Aug-16	$ 65.24	$ 59.32	$ 62.28	$ 1.980	3.03%	3.34%	3.18%
Average	$ 61.20	$ 56.84	**$ 59.02**		**3.24%**	**3.49%**	**3.36%**
Xcel Energy							
Jan-17	$ 41.43	$ 40.04	$ 40.74	$ 1.360	3.28%	3.40%	3.34%
Dec-16	$ 41.20	$ 38.22	$ 39.71	$ 1.360	3.30%	3.56%	3.42%
Nov-16	$ 41.75	$ 38.00	$ 39.88	$ 1.360	3.26%	3.58%	3.41%
Oct-16	$ 41.80	$ 39.08	$ 40.44	$ 1.360	3.25%	3.48%	3.36%
Sep-16	$ 43.49	$ 40.34	$ 41.92	$ 1.360	3.13%	3.37%	3.24%
Aug-16	$ 44.13	$ 41.07	$ 42.60	$ 1.360	3.08%	3.31%	3.19%
Average	$ 42.30	$ 39.46	**$ 40.88**		**3.22%**	**3.45%**	**3.33%**

Source: Yahoo! Finance

MDU Resources Group, Inc.
NDPSC Case No. PU-16-666

Case No.: PU-16-666
Witness: RA Polich
Date: 24-Feb-17
Exhibit No.: PSC - 4

Market Price to Book Values

Line	Company	Ticker	Aug 2016 to Jan 2017 Avg Price	2016 Book Value	M/B
1	ALLETE	ALE	61.50	37.90	1.62
2	Alliant Energy	LNT	37.72	18.05	2.09
3	Amer. Elec. Power	AEP	63.42	35.20	1.80
4	Ameren Corp.	AEE	50.24	29.60	1.70
5	Avista Corp.	AVA	40.84	25.55	1.60
6	Black Hills Corp.	BKH	60.04	30.10	1.99
7	CMS Energy	CMS	41.77	15.05	2.78
8	Consol. Edison	ED	74.09	46.80	1.58
9	DTE Energy	DTE	95.07	50.65	1.88
10	Edison Int'l	EIX	72.04	36.70	1.96
11	El Paso Electric	EE	45.90	26.15	1.76
12	Entergy Corp.	ETR	74.15	53.75	1.38
13	Exelon Corp.	EXC	34.02	27.90	1.22
14	IDACORP, Inc.	IDA	77.82	42.65	1.82
15	NorthWestern Corp.	NWE	57.24	34.40	1.66
16	OGE Energy Corp.	OGE	31.81	17.25	1.84
17	Otter Tail Corp.	OTTR	36.64	17.30	2.12
18	PG&E Corp.	PCG	61.12	35.20	1.74
19	Pinnacle West	PNW	75.92	42.60	1.78
20	PNM Resources, Inc.	PNM	32.87	22.70	1.45
21	Portland General	POR	42.73	26.20	1.63
22	PPL Corp.	PPL	34.32	14.56	2.36
23	Public Serv. Enterprise	PEG	42.59	26.00	1.64
24	SCANA Corp.	SCG	71.64	39.80	1.80
25	Sempra Energy	SRE	103.92	49.40	2.10
26	Southern Co.	SO	50.17	28.60	1.75
27	Vectren Corp.	VVC	50.40	21.55	2.34
28	WEC Energy Group	WEC	59.02	28.20	2.09
29	Xcel Energy	XEL	40.88	21.70	1.88

Source: August 2016 to January 2017 Average price from Yahoo! Finance.
2016 Estimated Book Values from Value Line reports dated
December 16, 2016 and January 27 and February 17, 2017.

MDU Resources Group, Inc.
NDPSC Case No. PU-16-666

Line No.	Company	Ticker	Industry Name	Safety Rank	Long-term Issuer Moody's	Long-term Issuer S&P	Long-term Issuer Fitch	Senior Unsecured Moody's	Senior Unsecured S&P	Senior Unsecured Fitch	Note
Utilities With S&P CCR of BBB, BBB+, or A-											
1	ALLETE	ALE	Electric Util. (Central)	2	A3	BBB+					
2	Alliant Energy	LNT	Electric Util. (Central)	2	Baa1	A-		Baa1			
3	Amer. Elec. Power	AEP	Electric Util. (Central)	2		A-	BBB	Baa1	BBB+	BBB	
4	Ameren Corp.	AEE	Electric Util. (Central)	2	Baa1	BBB+	BBB+	Baa1	BBB	BBB+	
5	Avista Corp.	AVA	Electric Utility (West)	2	Baa1	BBB					
6	Black Hills Corp.	BKH	Electric Utility (West)	2	Baa2	BBB	BBB+	Baa2	BBB	BBB+	
7	CMS Energy	CMS	Electric Util. (Central)	2		BBB+	BBB	Baa2	BBB	BBB	
8	Consol. Edison	ED	Electric Utility (East)	1	A3	A-	BBB+	A3	BBB+	BBB+	
9	DTE Energy	DTE	Electric Util. (Central)	2		BBB+	BBB+	Baa1	BBB	BBB+	
10	Edison Int'l	EIX	Electric Utility (West)	2	A3	BBB+	A-	A3	BBB	A-	
11	El Paso Electric	EE	Electric Utility (West)	2	Baa1	BBB		Baa1	BBB		
12	Entergy Corp.	ETR	Electric Util. (Central)	3	Baa3	BBB+		Baa3	BBB		
13	Exelon Corp.	EXC	Electric Utility (East)	3	Baa2	BBB	BBB	Baa2	BBB-	BBB	
14	IDACORP, Inc.	IDA	Electric Utility (West)	2	Baa1	BBB					
15	NorthWestern Corp.	NWE	Electric Utility (West)	3		BBB	BBB+	A3	BBB	A-	
16	OGE Energy Corp.	OGE	Electric Util. (Central)	2		A-	A-	A3	BBB+	A-	
17	Otter Tail Corp.	OTTR	Electric Util. (Central)	2		BBB	BBB-		BBB-	BBB-	
18	PG&E Corp.	PCG	Electric Utility (West)	3	Baa1	BBB+	A-	Baa1	BBB	A-	
19	Pinnacle West	PNW	Electric Utility (West)	1	A3	A-	A-	A3			
20	PNM Resources, Inc.	PNM	Electric Utility (West)	3	Baa3	BBB+					
21	Portland General	POR	Electric Utility (West)	2	A3	BBB					
22	PPL Corp.	PPL	Electric Utility (East)	2	Baa2	A-					
23	Public Serv. Enterprise	PEG	Electric Utility (East)	1		BBB+	BBB+	Baa2		BBB+	
24	SCANA Corp.	SCG	Electric Utility (East)	2	Baa3	BBB+	BBB-	Baa3	BBB	BBB-	
25	Sempra Energy	SRE	Electric Utility (West)	2	Baa1	BBB+	BBB+	Baa1	BBB+	BBB+	
26	Southern Co.	SO	Electric Utility (East)	2		A-	A-	Baa2	BBB+	A-	
27	Vectren Corp.	VVC	Electric Util. (Central)	2		A-					
28	WEC Energy Group	WEC	Electric Util. (Central)	1	A3	A-	BBB+	A3	BBB+	BBB+	
29	Xcel Energy	XEL	Electric Utility (West)	1	A3	A-	BBB+	A3	BBB+	BBB+	
Utilities Meeting the Ratings Screens But Eliminated For Other Reasons											
30	Avangrid, Inc.	AGR	Electric Utility (East)	2	Baa1	BBB+	BBB+			BBB+	Foreign control & other
31	CenterPoint Energy	CNP	Electric Util. (Central)	3	Baa1	A-	BBB	Baa1	BBB+	BBB	M&A activity
32	Dominion Resources	D	Electric Utility (East)	2		BBB+	BBB+	Baa2	BBB	BBB+	M&A activity
33	Duke Energy	DUK	Electric Utility (East)	2	Baa1	A-	BBB+	Baa1	BBB+	BBB+	M&A activity
34	G't Plains Energy	GXP	Electric Util. (Central)	3		BBB+		Baa2	BBB		M&A activity
35	NextEra Energy	NEE	Electric Utility (East)	2	Baa1	A-	A-		BBB		M&A activity
36	Westar Energy	WR	Electric Util. (Central)	2	Baa1	BBB+					M&A activity
Utilities Eliminated By the Credit Ratings Screen											
37	Eversource Energy	ES	Electric Utility (East)	1	Baa1	A	BBB+	Baa1	A-	BBB+	
38	FirstEnergy Corp.	FE	Electric Utility (East)	3	Baa3	BBB-	BBB-	Baa3	BB+	BBB-	
39	Hawaiian Elec.	HE	Electric Utility (West)	2		BBB-	BBB			BBB	M&A activity
40	MGE Energy, Inc.	MGEE	Electric Util. (Central)	1							No ratings
41	MDU Resources Group	MDU				BBB+	BBB+			A-	

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MONTANA-DAKOTAS UTILITIES
RATE INCREASE APPLIACTION
CASE NO. PU-16-666
OVER-RECOVERY EXAMPLE OF MR. GASKE'S PROPOSED FLOTATION COST ADJUSTMENT

ASSUMPTIONS:

Amount of Equity Issued:	$ 100.00	Million
Life Cycle of Asset:	40	Years
Depreciation Method:	Straight Line	
Flotation Percent:	3.2%	
Flotation Cost:	$ 3.20	Million
Return on Equity	8.00%	
Recovered Flotation Costs	$ 5.25	Million
Percent over Recovery	***64.0%***	

Year	Common Equity	Depreciation Reserve	Return on Equity	Return on Equity with Flotation	Flotation Cost Recovery	Total Flotation Cost Recoverd
1	$ 100.00	0	$ 8.00	8.256	$ 0.26	$ 0.26
2	$ 97.50	$ 2.50	$ 7.80	8.0496	$ 0.25	$ 0.51
3	$ 95.00	$ 2.50	$ 7.60	7.8432	$ 0.24	$ 0.75
4	$ 92.50	$ 2.50	$ 7.40	7.6368	$ 0.24	$ 0.99
5	$ 90.00	$ 2.50	$ 7.20	7.4304	$ 0.23	$ 1.22
6	$ 87.50	$ 2.50	$ 7.00	7.224	$ 0.22	$ 1.44
7	$ 85.00	$ 2.50	$ 6.80	7.0176	$ 0.22	$ 1.66
8	$ 82.50	$ 2.50	$ 6.60	6.8112	$ 0.21	$ 1.87
9	$ 80.00	$ 2.50	$ 6.40	6.6048	$ 0.20	$ 2.07
10	$ 77.50	$ 2.50	$ 6.20	6.3984	$ 0.20	$ 2.27
11	$ 75.00	$ 2.50	$ 6.00	6.192	$ 0.19	$ 2.46
12	$ 72.50	$ 2.50	$ 5.80	5.9856	$ 0.19	$ 2.65
13	$ 70.00	$ 2.50	$ 5.60	5.7792	$ 0.18	$ 2.83
14	$ 67.50	$ 2.50	$ 5.40	5.5728	$ 0.17	$ 3.00
15	$ 65.00	$ 2.50	$ 5.20	5.3664	$ 0.17	$ 3.17
16	$ 62.50	$ 2.50	$ 5.00	5.16	$ 0.16	$ 3.33
17	$ 60.00	$ 2.50	$ 4.80	4.9536	$ 0.15	$ 3.48
18	$ 57.50	$ 2.50	$ 4.60	4.7472	$ 0.15	$ 3.63
19	$ 55.00	$ 2.50	$ 4.40	4.5408	$ 0.14	$ 3.77
20	$ 52.50	$ 2.50	$ 4.20	4.3344	$ 0.13	$ 3.90
21	$ 50.00	$ 2.50	$ 4.00	4.128	$ 0.13	$ 4.03
22	$ 47.50	$ 2.50	$ 3.80	3.9216	$ 0.12	$ 4.15
23	$ 45.00	$ 2.50	$ 3.60	3.7152	$ 0.12	$ 4.27
24	$ 42.50	$ 2.50	$ 3.40	3.5088	$ 0.11	$ 4.38
25	$ 40.00	$ 2.50	$ 3.20	3.3024	$ 0.10	$ 4.48
26	$ 37.50	$ 2.50	$ 3.00	3.096	$ 0.10	$ 4.58
27	$ 35.00	$ 2.50	$ 2.80	2.8896	$ 0.09	$ 4.67
28	$ 32.50	$ 2.50	$ 2.60	2.6832	$ 0.08	$ 4.75
29	$ 30.00	$ 2.50	$ 2.40	2.4768	$ 0.08	$ 4.83
30	$ 27.50	$ 2.50	$ 2.20	2.2704	$ 0.07	$ 4.90
31	$ 25.00	$ 2.50	$ 2.00	2.064	$ 0.06	$ 4.96
32	$ 22.50	$ 2.50	$ 1.80	1.8576	$ 0.06	$ 5.02
33	$ 20.00	$ 2.50	$ 1.60	1.6512	$ 0.05	$ 5.07
34	$ 17.50	$ 2.50	$ 1.40	1.4448	$ 0.04	$ 5.11
35	$ 15.00	$ 2.50	$ 1.20	1.2384	$ 0.04	$ 5.15
36	$ 12.50	$ 2.50	$ 1.00	1.032	$ 0.03	$ 5.18
37	$ 10.00	$ 2.50	$ 0.80	0.8256	$ 0.03	$ 5.21
38	$ 7.50	$ 2.50	$ 0.60	0.6192	$ 0.02	$ 5.23
39	$ 5.00	$ 2.50	$ 0.40	0.4128	$ 0.01	$ 5.24
40	$ 2.50	$ 2.50	$ 0.20	0.2064	$ 0.01	$ 5.25
41	$ -	$ 2.50	$ -	0	$ -	$ 5.25
TOTAL			**$ 164.00**	**169.248**	**$ 5.25**	

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MONTANA-DAKOTAS UTILITIES
RATE INCREASE APPLIACTION
CASE NO. PU-16-666
EXAMPLE DECOMMISSIONING COST IMPACT ON MONTANA RATE PAYERS

DECOMMISSIOING FUNDS COLLECTION THROUGH 2014

DECOMMISSIONING COLLECTED			INFLATION ADJUSTMENTS		
YEAR	Collected	Cumulative	2016 Dollar Value	2016 Equivalent Collected Value	2016 Equivalent Cumulative Value
1995	$335,610	$335,610	1.57	$526,907	$526,907
1996	$335,610	$671,219	1.52	$510,127	$1,037,034
1997	$335,610	$1,006,829	1.49	$500,058	$1,537,092
1998	$335,610	$1,342,439	1.46	$489,990	$2,027,083
1999	$335,610	$1,678,049	1.43	$479,922	$2,507,004
2000	$335,610	$2,013,658	1.39	$466,497	$2,973,502
2001	$335,610	$2,349,268	1.35	$453,073	$3,426,575
2002	$335,610	$2,684,878	1.33	$446,361	$3,872,936
2003	$335,610	$3,020,487	1.3	$436,293	$4,309,229
2004	$335,610	$3,356,097	1.26	$422,868	$4,732,097
2005	$335,610	$3,691,707	1.22	$409,444	$5,141,541
2006	$335,610	$4,027,316	1.19	$399,376	$5,540,916
2007	$335,610	$4,362,926	1.15	$385,951	$5,926,867
2008	$335,610	$4,698,536	1.11	$372,527	$6,299,394
2009	$335,610	$5,034,146	1.11	$372,527	$6,671,921
2010	$335,610	$5,369,755	1.1	$369,171	$7,041,092
2011	$335,610	$5,705,365	1.06	$355,746	$7,396,838
2012	$335,610	$6,040,975	1.04	$349,034	$7,745,872
2013	$335,610	$6,376,584	1.03	$345,678	$8,091,550
2014	$335,610	$6,712,194	1.01	$338,966	$8,430,516

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MONTANA-DAKOTAS UTILITIES
RATE INCREASE APPLIACTION
CASE NO. PU-16-666
EXAMPLE DECOMMISSIONING COST IMPACT ON MONTANA RATE PAYERS

2016 VALUE OF DECOMMISSIONING REFUNDS & NET RATE PAYER IMPACT

	Depreciation Reduction Amount	CPI *	2016 Value of Refund
2016	$671,219	1.000	$671,219
2017	$671,219	0.99	$664,507
2018	$671,219	0.980	$657,795
2019	$671,219	0.970	$651,217
2020	$671,219	0.960	$644,639
2021	$671,219	0.951	$638,193
2022	$671,219	0.941	$631,746
2023	$671,219	0.932	$625,429
2024	$671,219	0.922	$619,111
2025	$671,219	0.913	$612,920

2016 Value of Decommissioning Depreciation Reduction	**$6,416,777**
2016 Value of Decommissioning Collections	**$8,430,516**
Rate Payer Benefit/(Loss)	**-$2,013,738**
Rate Payer Percent Loss	**23.9%**

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MONTANA-DAKOTAS UTILITIES
RATE INCREASE APPLIACTION
CASE NO. PU-16-666
EXAMPLE DECOMMISSIONING COST IMPACT ON MONTANA RATE PAYERS

LIST OF SIMILAR SMALL POWER PROJECT COSTS

Power Plant	Technology	Fuel Type	Nameplate Capacity	Year in Service	Cost Info	Cost per kW	Cost Source
Lewis & Clark Smart Power Generation	**Internal Combustion**	**Gas**	**18.6**	**2015**	**$47,194,515**	**$2,537**	MDU Filing
Rentech Pasadena Cogeneration Project	Steam Turbine	Waste Heat	15.4	2015	$30,000,000	$1,948	SNL cost estimate
Roundtop	Internal Combustion	Gas	22.0	2015	$31,500,000	$1,432	regulatory filing
--- CONFIDENTIAL ---	Internal Combustion	Natural Gas	99.0	2015*	$120,912,150	$1,221	Zachary Engineering
Fairmont Energy Station	Internal Combustion	Gas	26.0	2014	$30,000,000	$1,154	SNL cost estimate
--- CONFIDENTIAL ---	Combined Cycle	Natural Gas	540.0	2017*	$602,223,122	$1,115	GDS Associates
Central Utility CC Plant at White Oak	Combined Cycle	Gas	20.0	2014	$22,000,000	$1,100	SNL cost estimate
Jameson Energy Project	Gas Turbine	Gas	27.6	2014	$26,220,000	$950	SNL cost estimate
HP Hood Cogeneration	Gas Turbine	Gas	15.0	2015	$14,250,000	$950	SNL cost estimate
--- CONFIDENTIAL ---	Combustion Turbine	Natural Gas	43.5	2018*	$40,200,000	$924	GDS Associates
Quay County Generating Station (Tucumcari)	Gas Turbine	Oil	27.0	2013	$19,800,000	$733	SNL cost estimate
Haskett III Gas Turbine	Combustion Turbine	Natural Gas	88.0	2014	$53,177,264	$604	MDU Filing
Fredericktown Energy Center	Gas Turbine	Gas	27.6	2015	$16,000,000	$580	SNL cost estimate

Notes:
*Projected operation date.

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of Montana-Dakota Utilities Co.,

a Division of MDU Resources Group, Inc.

2016 Electric Rate Increase Application

Case No. PU-16-666

DIRECT TESTIMONY

OF

JACOB M. THOMAS, P.E.

ON BEHALF OF THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

ADVOCACY STAFF

February 24, 2017

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Q. Please state your name and place of employment.

A. My name is Jacob M. Thomas. I am employed by GDS Associates, Inc. ("GDS"), and my office is located at 1850 Parkway Place, Suite 800, Marietta, Georgia 30067.

Q. What position do you hold?

A. I hold the position of Senior Project Manager.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this testimony on behalf of North Dakota Public Service Commission Advocacy Staff ("Staff").

Q. What is your educational background?

A. I graduated from the Georgia Institute of Technology with a Bachelor of Science in Industrial Engineering in 2000. I received a Master's in Business Administration with a concentration in Finance from Auburn University in 2006.

Q. Please describe your work experience.

A. I began working with GDS in June 1996 as a cooperative student while attending the Georgia Institute of Technology. After graduation in December 2000, I accepted a full-time position in GDS' Distribution Services department and have risen to my current position of Senior Project Manager in that department. In the past 20 years, I have provided statistical, financial, and economic consulting to utilities and regulatory agencies nationwide.

In the area of statistics, I have provided services to clients with respect to load forecasting, market research, sample design, load research, measurement and verification, and other statistical modeling. I have produced dozens of load forecasts, managed multiple customer survey processes, and performed impact evaluations of demand response and energy efficiency programs for several clients. I have also evaluated short-term and long-term price elasticity of demand for forecasting purposes.

In the areas of finance and economics, I specialize in retail and wholesale cost of service development and design, retail and wholesale rate design, financial forecasting, economic impact analysis, and benefit-cost analysis of demand response programs. In the past three years, I have managed or had significant input into cost of service, rate design, and financial forecasting projects for twenty different clients. I have performed benefit-cost analyses for an additional eight clients in that time.

My resume is provided as exhibit PSC-8.

Q. Do you have any professional registrations and memberships?

A. Yes, I am a registered Professional Engineer in Georgia. I am a member of the Institute of Industrial Engineers and the American Statistical Association.

Q. Have you testified in North Dakota in the past?

A. I have not.

Q. Have you testified in any other regulatory proceedings?

A. I have testified as an expert witness in several other states and been a co-author of joint reports filed in cases as well. I testified as an expert before the Vermont Public Service board, providing testimony regarding the economic impacts of continued operations of the Vermont Yankee nuclear power plant. I testified in the area of weather normalization of gas sales before the Michigan Public Service Commission. I also testified before the North Carolina Utilities Commission, providing testimony supporting cost of service computations for an intervenor. I have also been a co-author of reports in connection to cases before the Delaware Public Service Commission, the Kentucky Public Service Commission, and the Utah Public Service Commission. In those joint reports, prepared in coordination with other GDS experts, I was tasked with focusing on demand response, load research, and load forecasting issues.

TESTIMONY PURPOSE AND SUMMARY

Q. What is the purpose of your testimony?

A. My testimony introduces revised cost of service results and revenue allocations to rate classes reflecting the revenue requirement recommended by Staff witness Richard A. Polich. Furthermore, I discuss the load research study used by Montana-Dakota Utilities, Co. ("MDU") to estimate class contributions to demands used to allocated demand-related costs in the cost of service study. Finally, I recommend changes to several components of MDU's proposed rate designs.

Q. How is your testimony organized?

A. I have organized my testimony into the following sections:

1. **Cost of Service** – Calculation of Cost of Service results that reflect all adjustments to the revenue requirement recommended by Staff witness Richard A. Polich.
2. **Recommended Revenue Allocation to Classes** – Allocation of the revenue requirement to classes reflecting Staff witness Richard A. Polich's recommended revenue requirement.
3. **Load Research** – Review of and recommendations related to load research supporting estimates for class demand allocators.
4. **Rate Design** – Recommendations related to rate design irrespective of class revenue requirements.
5. **Conclusions** – Summary of testimony and recommendations.

Q. Have you prepared any Exhibits?

A. Yes, the following is a list of Exhibits included with my testimony:

EXHIBIT	**DESCRIPTION**
PSC-8	Jacob M. Thomas Resume
PSC-9	Adjusted Cost of Service Results
PSC-10	Adjusted Revenue Allocation to Customer Classes
PSC-11	General Winter Bill Rate Comparisons

COST OF SERVICE

Q. What have you prepared with respect to cost of service?

A. I have prepared a cost of service study that reflects all recommended adjustments to the revenue requirement, including changes to investments, and expenses made by Staff witness Richard A. Polich. The resultant study outputs are shown in Exhibit PSC-9.

Q. Please summarize how you prepared the Staff adjusted cost of service study.

A. I used MDU's electronic spreadsheet version of their cost of service model provided in response to Staff Data Request 1 question 2. First, I computed an updated version of the Cost of Service to reflect new projected income statements and rate base for 2017. Then, I created a second version of that model and adjusted certain inputs to reflect the changes recommended by Mr. Polich.

Q. Please describe how you prepared the Cost of Service that reflects new projected information.

A. I used revised projected income and rate base information provided by MDU in their response to Staff Data Request Set 1, Question 1 to obtain updated 2017 projections[1]. I then input that data into the Cost of Service model provided by MDU in response to Staff Data Request Set 1, Question 2[2]. I then checked to ensure that the resultant North Dakota income statement and Rate of Return from my Cost of Service model matched that in the data supplied by MDU in response to Staff Data Request Set 1 Question 1.

Q. Please describe how you prepared the Cost of Service that reflects Mr. Polich's recommended adjustments.

A. I started with the Cost of Service model that reflects the updated 2017 projections, described above. Then, I adjusted certain inputs in the Cost of Service model to reflect those adjustments recommended by Staff witness Mr. Polich. The following list describes each of the adjustments I made to produce the adjusted study.

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[1] Two Excel files as provided by MDU were used to update all inputs into the Cost of Service model: "ND Elec Rate Base 16 – Excl Wind.xlsm" and "ND Electric Income Statement (2016).xlsx".

[2] The Cost of Service Model was provided in Excel format and is called "Response No. 1.2 Statement M.xlsx"

- Production plant in service and accumulated depreciation rate base adjustments and an adjustment to production plant depreciation expense to reflect Mr. Polich's recommendations with respect to the Lewis & Clark RICE units.
- Working capital adjustments in rate base to reflect Mr. Polich's recommendations with respect to the loss on the sale of housing and plant decommissioning.
- Adjustment to operating expenses to reflect recommended adjustment to bonus and incentive compensation expenses.
- Adjustments to accumulated deferred income tax in working capital and income tax expenses to reflect the tax implications of the all adjustments recommended by Mr. Polich.

Q. Please summarize the resultant adjusted cost of service results.

A. Table JMT 1 provides the North Dakota system and class rates of return for the MDU cost of service as filed and for the Cost of Service model that reflects the updated 2017 projections. Furthermore, I show the relative rate of return, which is the class rate of return divided by the North Dakota system rate of return.

Table JMT 2 provides the rates of return and relative rates of return for the Cost of Service that reflects the updated 2017 projections and the model adjusted to reflect Staff's recommended adjustments.

TABLE JMT-1
Comparison of North Dakota Class Cost of Service Rates of Return
As Filed COS versus COS Adjusted to Reflect Updated 2017 Projections

Line No.	Class	As Filed MDU ROR[1]	As Filed Relative ROR[2]	Updated 2017 ROR	Updated 2017 Relative ROR[3]
(a)	(b)	(c)	(d)	(e)	(f)
1	Residential Rate 10	3.818%	0.654	4.027%	0.665
2	Small General Rate 20	5.395%	0.924	5.638%	0.931
3	Irrigation Rate 25	-1.195%	(0.205)	-1.012%	(0.167)
4	Large General Primary Rate 30	7.580%	1.298	7.781%	1.284
5	Large General Secondary Rate 30	8.416%	1.441	8.636%	1.426
6	TOD Large General Rate 31 Primary	4.198%	0.719	4.010%	0.662
7	TOD Large General Rate 31 Secondary	5.844%	1.001	6.060%	1.000
8	Space Heating Rate 32	6.077%	1.041	6.233%	1.029
9	Small Municipal Rate 40	2.701%	0.463	3.135%	0.517
10	Municipal Lighting Rate Primary 41	13.080%	2.240	13.420%	2.215
11	Municipal Lighting Rate Secondary 41	10.847%	1.858	11.516%	1.901
12	Municipal Pumping Primary Rate 48	2.020%	0.346	2.261%	0.373
13	Municipal Pumping Secondary Rate 48	4.070%	0.697	4.349%	0.718
14	Outdoor Lighting Rate 52	11.879%	2.034	12.011%	1.983
15	Interruptible Demand Response Rate 38	6.616%	1.133	6.844%	1.130
16	**Total North Dakota**	**5.839%**	**1.000**	**6.058%**	**1.000**

1 - From Statement M, Pages 1-15.
2 - Column C in each row divided by column C, line 16, Total North Dakota, 5.839%.
3 - Column E in each row divided by column E, line 16, Total North Dakota, 6.058%.

TABLE JMT-2
Comparison of North Dakota Class Cost of Service Rates of Return
COS Adjusted to Reflect Updated 2017 Projections versus COS Adjusted to Reflect Staff Recommendations

Line No.	Class	Updated 2017 ROR	Updated 2017 Relative ROR[1]	Staff Adjusted ROR	Staff Adjusted Relative ROR[2]
(a)	(b)	(c)	(d)	(e)	(f)
1	Residential Rate 10	4.027%	0.665	4.643%	0.690
2	Small General Rate 20	5.638%	0.931	6.273%	0.933
3	Irrigation Rate 25	-1.012%	(0.167)	-0.407%	(0.061)
4	Large General Primary Rate 30	7.781%	1.284	8.525%	1.267
5	Large General Secondary Rate 30	8.636%	1.426	9.396%	1.397
6	TOD Large General Rate 31 Primary	4.010%	0.662	4.910%	0.730
7	TOD Large General Rate 31 Secondary	6.060%	1.000	6.729%	1.000
8	Space Heating Rate 32	6.233%	1.029	6.940%	1.032
9	Small Municipal Rate 40	3.135%	0.517	3.588%	0.533
10	Municipal Lighting Rate Primary 41	13.420%	2.215	14.978%	2.227
11	Municipal Lighting Rate Secondary 41	11.516%	1.901	11.918%	1.772
12	Municipal Pumping Primary Rate 48	2.261%	0.373	2.797%	0.416
13	Municipal Pumping Secondary Rate 48	4.349%	0.718	4.937%	0.734
14	Outdoor Lighting Rate 52	12.011%	1.983	13.004%	1.933
15	Interruptible Demand Response Rate 38	6.844%	1.130	7.486%	1.113
16	**Total North Dakota**	**6.058%**	**1.000**	**6.727%**	**1.000**

1 - Column C in each row divided by column C, line 16, Total North Dakota, 6.058%.
2 - Column E in each row divided by column E, line 16, Total North Dakota, 6.727%.

Although the class-by-class rates of return are similar in all three versions of the Cost of Service, the Staff recommended adjustments do narrow the range of outcomes. By observing the relative ROR statistic, one can see that the range of class returns as a ratio of the overall North Dakota system return narrows under the Staff recommended version. Relative rates of return range from -0.205 to 2.240 under the MDU filed Cost of Service. Under the Staff adjusted Cost of Service, relative rates of return range from -0.061 to 2.227.

REVENUE ALLOCATION TO CLASSES

Q. Please describe your recommended revenue allocation.

A. I started with the overall revenue requirement as recommended by Staff witness Richard A. Polich. Mr. Polich recommends a base rate revenue increase of $513,316. Then, I evaluated the rates of return by class from the Staff adjusted cost of service, as shown in Table JMT 2 above. Finally, I prepared an allocation of the Staff recommended rate increase to the classes as shown in Table JMT 3 below:

TABLE JMT-3
Staff Recommended Base Rate Revenue Increases by Customer Class

Customer Class	Recommended Rate Increase* Amount ($000)	%
Residential Service	$316	0.43%
Small General Service	$45	0.35%
Large General Service	$136	0.15%
Lighting	$3	0.15%
Municipal Pumping	$15	0.55%
Total North Dakota Electric	$515	0.28%

*Exclusive of Renewable Rider and Transmission Cost Adjustment Rider.

Q. Please describe how you allocated Mr. Polich's recommended revenue increase to the various customer classes.

A. MDU witness Tamie Aberle describes the method by which the Company allocated their requested revenue increase to the classes. On page 6 of her direct testimony in lines 8-14, she describes a two-step process used to determine the maximum and minimum increases to be placed on any one class because "It was determined that mitigation was necessary in order to balance the fair return standard with the recognition of customer impacts." I employed a similar two-step process to Ms. Aberle, although I modified it to reflect the lower overall percent increase recommended by Staff witness Polich. I set a maximum percent increase of 2.0 times the overall North Dakota recommended increase and a minimum of 0.5 times the overall increase. The resultant maximum increase is 0.56% and minimum increase is 0.14%. Exhibit PSC-10, page 1 shows the revenue allocation I recommend.

Next, I looked at the class rates of return prior to the revenue increase, and assigned minimum and near minimum increases to the two classes earning higher than system rates of return. Total Lighting and Total General Service received a 0.15% increase.

Total Municipal Pumping, which currently has a rate of return below the North Dakota system was then assigned the highest rate increase of 0.55%. Next, the Total General Service increase was set at 0.35% to recognize it has a lower than system return but higher return than Residential and Municipal Pumping. The Residential increase was then computed to recover the remaining revenue increase, which results in an increase of 0.43%.

My recommended revenue allocation provides for reasonable increases on all classes and moves all classes closer to equitable rates of return, as shown in Table JMT 4.

TABLE JMT-4
Resultant Rates of Return After Staff Recommended Revenue Increases

	Prior to Rate Increase		After Rate Increase	
Customer Class	Rate of Return	Relative ROR	Rate of Return	Relative ROR
Residential Service	4.643%	0.690	4.724%	0.696
Small General Service	6.103%	0.907	6.174%	0.909
Large General Service	9.050%	1.345	9.088%	1.339
Lighting	12.314%	1.831	12.344%	1.818
Municipal Pumping	4.252%	0.632	4.357%	0.642
Total North Dakota Electric	6.727%	1.000	6.789%	1.000

LOAD RESEARCH

Q. What did you review with respect to MDU's load research?

A. In response to Staff data request Set 2, Question 30, MDU provided several spreadsheets and responses describing the load research used in their cost of service study allocator development. I reviewed this information to ascertain if industry standard techniques were used by MDU. The load research information is used to compute the 12-CP demands for each class and is therefore an important aspect of MDU's cost of service model.

Q. Do you have any recommended adjustments to the load research study?

A. Yes, I do. I recommend MDU use a different methodology for sample selection. I also recommend MDU use a different methodology to perform the data expansion to expand sample demands to class demands. I will discuss each in more detail below.

Q. How does MDU select its load research samples?

A. According to MDU's response to Staff data request Set 2, Question 30.c: "Montana-Dakota prepared random samples for rate classes having sufficient numbers of customers to make a census impractical and for which interval data were available." In load research, when interval data is used for every customer in a class, it is called a census. The sample size was designed to achieve a 90% confidence level with a 10% error tolerance. For the sampled classes, the Company randomly selected accounts that had 12 months of 2015 billing data. Data for all customers on Rate class 130 were included so this class was not sampled. Very small sample sizes were used in some cases including class 250 (2 out of 40 accounts), class 300 (2 out of 36 accounts), class 323 (2 out of 536 accounts), and class 400 (8 out of 39 accounts).

Q. What changes do you recommend for sample design and selection?

A. I recommend that MDU generally employ a stratified random sampling scheme for its load research program. With a stratified random sample, the class is divided into strata and a random sample of customers from each stratum are drawn. If the individual strata of customers are more homogenous than the overall population, then stratification can increase the precision of sample estimates and/or reduce the overall sample size required. For those classes that have demand charges and demands are recorded in MDU's billing system, then the demand can be a natural stratification variable. For other classes, stratifying based on energy is often employed in the industry. For classes with very few customers (less than 50) or classes with highly homogenous load characteristics, a simple random sample is likely to be equally representative and provide similar precision to a stratified approach. For classes with fewer than 50 accounts, using interval data for all customers is preferable to either a stratified or simple random sample.

Q. What changes do you recommend for the data expansion?

A. Data expansion is the process by which a load researcher uses the sample data to expand it to represent the entire rate class. Based on MDU's response to Staff data request 2, question 30, I conclude that MDU uses a mean-per unit ("MPU") expansion approach. In an MPU expansion, the load research data is used to calculate a variable of interest (for instance, a CP demand for a given month) on a per-customer basis. That variable per customer ratio is then multiplied by the total number of customers in the class to estimate the variable of interest for the entire class.

I recommend MDU change to a ratio expansion technique. In ratio expansion, correlation of the variable of interest with another variable that is available for the sample customers and the population is used to obtain increased precision in the expanded estimate. As described in the *Load Research Manual*, produced by the Association of Edison Illuminating Companies:

> "Ratio estimation is a technique that can take advantage of the correlation of the variable of interest y with another variable *x* to obtain increased precision. Class demand estimates for rate classes and other populations with 'known' total energy use *X* are adjusted by the ratio of demand y to energy use x for the sample. When *x* and *y* are sufficiently correlated, the relative variance of the estimated ratio is less than the relative variance of either *x* or *y* alone. That is, knowledge of *x* provides information about *y*. As a result, the ratio estimator has better precision than the mean-per-unit estimator, which ignores the information about *x*."[3]

This paragraph concludes that, if there is positive correlation between class energy and class demand, then the ratio estimation technique will improve precision. Given the high likelihood that such a

[3] Association of Edison Illuminating Companies. *Load Research Manual*. 2nd ed. 2001. Page 7-8.

positive correlation exists for MDU's rate classes, I recommend use of the ratio estimation technique to improve the precision of demand estimates.

Q. Do you recommend these adjustments to the load research be incorporated into MDU's cost of service and rate design for Case PU-16-666?

A. I do not recommend that these changes be made in this case. Changing the sample requires starting the load research process from step 1 and could not be accomplished in a timely manner for the purposes of this case. Rather, I recommend MDU make these changes to its load research program for future rate case and other load research needs.

RATE DESIGN

Q. Please summarize the issues you will discuss with respect to rate design.

A. I make recommendations with respect to the rate design for three rates: Residential Service Rate 10, Optional Residential ETS Rate 13, and SGS Rate 20. I also discuss the concept of a residential demand rate as a future concept for MDU to consider.

Q. What do you recommend regarding rate design for Residential Service Rate 10?

A. I recommend MDU eliminate the declining block rate for the energy charge in winter months. A declining block rate design is typically one that incorporates customer-related fixed costs into the first energy block when the basic service charge does not recover full customer-related costs. With MDU's proposed basic service charge of $0.65 per day, the full customer-related cost is being recovered through the basic service charge, eliminating the need to recover additional customer costs in the first 750 kWh per month in winter months.

Furthermore, the long-run marginal cost of energy produced is increasing and not decreasing, as utilities rely on newer and more emission-efficient units to produce marginal energy in the future. A declining block rate does not reflect the fact that marginal costs will increase over the long-run.

Q. How does moving from a declining block rate to a flat rate in the winter impact residential consumers?

A. Changing the rate structure in winter months to a flat energy charge will help ease the impacts on low usage customers associated with the increasing Basic Service Charge. In Exhibit PSC-11, I provide general winter bill rate comparisons that demonstrate that fact. On page 1, I show a comparison of the present Rate 10 for winter months versus MDU's proposed rate with the declining block rate. On page 2, I show a comparison of the present Rate 10 for winter months versus a flat rate energy charge designed to recover the same revenue for those kWh as MDU's proposed design. When comparing the bills at lower usage levels, it is clear that the flat energy charge helps lower usage customers absorb the impact of increasing the Basic Service Charge. For instance, looking at line 7 on pages 1 and 2 of Exhibit PSC-11, a customer that uses 500 kWh in a given winter month will see an increase of $8.14, or 13.7%, on that bill under MDU's proposed rates with a declining energy block. Under the flat energy charge, that customer would see a $2.31, or 3.9%, increase on that bill.

Q. **How did you compute the flat energy charge you used in Exhibit PSC-11, Page 2?**

A. I used the rate design statements provided by MDU to compute a flat energy charge in winter months of $0.04900 per kWh. In Statement N, page 7, MDU shows that the winter energy charges are designed to recover $25,688,615 in revenue over 524,290,825 kWh. That results in an average rate of $0.04900 per kWh, which is what I used for the rate comparison in Exhibit PSC-11 page 2.

Q. What recommendations do you have for Residential Electric Thermal Storage Service Rate 13?

A. To be consistent with the design of the Residential Service Rate 10, I recommend MDU eliminate the declining block energy charge in the winter on-peak energy component of the rate. The same reasoning with respect to recovery of customer-related fixed costs and reflecting that marginal costs will increase over the long-run apply to the Residential Electric Thermal Storage customers during their on-peak period.

Q. What recommendations do you have for Small General Service Rate 20?

A. To be consistent with the design of the Residential Service Rate 10, I recommend MDU eliminate the declining block energy charge in the winter on-peak energy component of the rate. The same reasoning with respect to recovery of customer-related fixed costs and reflecting that marginal costs will increase over the long-run apply to the Small General Service class of customers.

Q. Have you prepared rate comparisons that demonstrate the comparative impacts of this change on Rate 20?

A. I have, they are shown in Exhibit PSC-11 pages 3 and 4. The flat energy charge was computed in a manner consistent with the approach I described for Rate 10, using Schedule N page 10.

CONCLUSION

Q. Can you summarize the recommendations you make in your testimony?

A. Yes. First, I have prepared and presented adjusted cost of service results that reflect the adjustments recommended by Staff witness Richard A. Polich. Second, I have developed a recommended schedule of revenue increase allocations to the rate classes that reflect the total North Dakota system revenue requirements recommended by Mr. Polich.

I also reviewed MDU's load research information provided in this case and have made two recommendations for future load research studies. I recommend using a stratified random sampling technique for selecting samples in the next load research study. I also recommend using a ratio estimation technique to expand the sample data into class demand estimates.

Finally, I have recommended elimination of the declining block energy charge structure for Rate 10, Rate 13, and Rate 20 winter months. I prepared rate comparisons that demonstrate eliminating the declining block structure helps lower usage customers absorb the bill increases associated with increasing the Basic Service Charges on those rates.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF NORTH DAKOTA

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Application of
MONTANA-DAKOTA UTILITIES CO.,
A Division of MDU Resources Group, Inc.
for authority to Increase Rates for Electric Service in North Dakota

Case No. PU-16-666

AFFIDAVIT OF
Jacob M. Thomas

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

Jacob M. Thomas

Subscribed and sworn to before me
this **24th day of February, 2017.**

Notary Public

SEAL

K. RUDITYS
MY COMMISSION EXPIRES
NOTARY
PUBLIC
FEBRUARY 10, 2019
COBB COUNTY, GEORGIA

GDS Associates, Inc
ENGINEERS & CONSULTANTS

JACOB M. THOMAS, P.E.

Senior Project Manager

EDUCATION

Master of Business Administration, Finance, Auburn University, 2006

Bachelor of Science in Industrial Engineering, Cooperative Program, With Highest Honors, Georgia Institute of Technology, 2000

PROFESSIONAL REGISTRATION

Registered Professional Engineer in the State of Georgia

PROFESSIONAL MEMBERSHIPS

National Society of Professional Engineers (NSPE)
American Statistical Association (ASA)
Institute of Industrial Engineers (IIE)

PROFESSIONAL EXPERIENCE

GDS Associates, Inc., June 1996 to Present

Employed as cooperative student and began full time employment in 2000. During his career at GDS, Mr. Thomas has developed expertise and experience in many areas of utility practice including load & financial forecasting, residential consumer surveys, load research, cost of service studies, retail and wholesale rate design, economic impact analysis, benefit-cost analyses, load management evaluation, statistical impact analysis, and market research.

PROJECT EXPERIENCE

General Experience Includes:

- Designed cost of service models and performed retail rate analysis for municipals and cooperatives in Alabama, Alaska, Arkansas, Florida, Georgia, Indiana, Massachusetts, Ohio, Pennsylvania, South Carolina, Texas, and Virginia. Specific work has included development of cost allocation factors in various areas of operation, calculation of impacts of rate changes to customers, determination of the company's financial competitive position, classification of plant investment and operating expenses, development of pro forma financial statements, and alternative rate design calculations.
- Designed a cost of service model template for use by Hoosier Energy. Developed a functional

spreadsheet-based model and performed a training seminar with Hoosier staff.

- Prepared financial forecasts for electric cooperatives in South Carolina, Virginia, Tennessee and Georgia, and for municipals in Arkansas and Pennsylvania. Work included regression analysis, review of current long-term debt situation, customer and demand forecasts, plant forecasts, and sensitivity analysis.
- Completed an economic impact analysis of instituting a Renewable Portfolio Standard in the state of North Carolina. Direct, indirect, and induced job impacts were measured for construction, operations and maintenance, and pertinent fuel supplies for various conventional and renewable resources, as well as effects of electricity price increases on residential and commercial consumers.
- Economic impact analysis of continued operation of nuclear power plant in Vermont. Analysis included impacts to Vermont economy in general, Vermont government, and in-state utility ratepayers. Prepared testimony as an expert witness on economic analysis on behalf of the Department of Public Service.
- Expert witness in a natural gas retail rate study in Michigan. Subject of testimony was weather normalization methodologies in forecasting.
- Developed state-wide energy supply and consumption projections by major customer classification and type of fuel for Vermont Department of Public Service and Virginia Department of Mines, Minerals, and Energy. Utilized Energy Information Administration data and econometric and trending techniques to complete projections.
- Assisted in development of wholesale rates for G&Ts in Indiana, Minnesota and Wisconsin. Work involved projections of cost pools and billing units, development of pro forma rates and impacts on member systems, evaluation of rate alternatives and riders, and considering the implications of an aggressive load management program.
- Instructor at Institute of Public Utilities Forecasting Workshop held in 2012. Taught on the subject of Statistically Adjusted End-Use models.

REGULATORY EXPERIENCE

- Delaware Public Service Commission (Co-Author of Joint Report – Evaluation of Delmarva Power & Light Integrated Resource Plan)
- Kentucky Public Service Commission (Panel Representative in Big Rivers Electric Corporation Integrated Resource Plan)
- Michigan Public Service Commission (Expert Witness – Weather Normalization)
- North Carolina Utilities Commission (Expert Witness – Cost of Service Modeling)
- Utah Public Service Commission (Co-Author of Joint Report – Evaluation of PacifiCorp Load Forecast)
- Vermont Public Service Board (Expert Witness – Economic Impact Analysis of Vermont Yankee)

Case No.: PU-16-666
Witness: JM Thomas
Date: 24-Feb-17
Exhibit No.: PSC-9

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY
NORTH DAKOTA
Embedded Class Cost of Service Study
Cost of Service by Component
Projected 2017 - Reflecting Staff Recommended Adjustments
(000's)

	Total North Dakota	Residential Rate 10 Demand Prod. & Trans.	Residential Rate 10 Demand Distribution	Residential Rate 10 Energy	Residential Rate 10 Customer	Total Residential Rate 10
Rate Base	520,229	145,788	34,043	1,328	62,055	243,214
Operating Income for Proposed Return	38,805	10,877	2,539	99	4,629	18,144
Current Operating Income	34,998	(12,705)	(2,218)	26,388	(173)	11,292
Increase in Operating Income	3,807	23,582	4,757	(26,289)	4,802	6,852
Related Taxes for Increase						
State & Federal Income Taxes	2,311	14,328	2,891	(15,977)	2,918	4,160
Total Increase in Revenue	6,118	37,910	7,648	(42,266)	7,720	11,012
Total Revenue Before Increase	186,308	1,471	427	62,441	11,201	75,540
Total Cost of Service Required from Rates	192,426	39,381	8,075	20,175	18,921	86,552
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	1,471	427	1,213	980	4,091
Revenue Required from Rates	182,917	37,910	7,648	18,962	17,941	82,461
Projected Rate of Return Before Increase	6.727%					4.643%
Projected Billing Units						
Kwh	2,014,529,000	770,939,000	770,939,000	770,939,000		
Kw Demand	3,304,802					
Bills	1,170,228				960,036	
Unit Cost of Service						
$ per Kwh		0.049	0.010	0.025		
$ per Kw Demand						
$ per Customer Per Month					18.69	

Operating Income/Inverse of Federal income tax rate:	62.1985%
Operating Income for Proposed Return:	7.459%

Case No.: PU-16-666
Witness: JM Thomas
Date: 24-Feb-17
Exhibit No.: PSC-9

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY
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Embedded Class Cost of Service Study
Cost of Service by Component
Projected 2017 - Reflecting Staff Recommended Adjustments
(000's)

	Total North Dakota	Small General Rate 20: Demand Prod. & Trans.	Small General Rate 20: Demand Distribution	Small General Rate 20: Energy	Small General Rate 20: Customer	Total Small General Rate 20
Rate Base	520,229	21,245	4,424	194	12,015	37,878
Operating Income for Proposed Return	38,805	1,585	330	14	896	2,825
Current Operating Income	34,998	(1,854)	(287)	3,878	639	2,376
Increase in Operating Income	3,807	3,439	617	(3,864)	257	449
Related Taxes for Increase						
State & Federal Income Taxes	2,311	2,090	375	(2,348)	156	273
Total Increase in Revenue	6,118	5,529	992	(6,212)	413	722
Total Revenue Before Increase	186,308	212	55	9,157	3,126	12,550
Total Cost of Service Required from Rates	192,426	5,741	1,047	2,945	3,539	13,272
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	212	55	147	176	590
Revenue Required from Rates	182,917	5,529	992	2,798	3,363	12,682
Projected Rate of Return Before Increase	6.727%					6.273%
Projected Billing Units						
Kwh	2,014,529,000	112,526,000	112,526,000	112,526,000		
Kw Demand	3,304,802					
Bills	1,170,228				138,144	
Unit Cost of Service						
$ per Kwh		0.049	0.009	0.025		
$ per Kw Demand						
$ per Customer Per Month					24.34	

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY
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Cost of Service by Component
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(000's)

	Total North Dakota	Irrigation Rate 25 Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total Irrigation Rate 25
Rate Base	520,229	92	241	2	156	491
Operating Income for Proposed Return	38,805	7	18	0	12	37
Current Operating Income	34,998	(7)	(6)	17	(6)	(2)
Increase in Operating Income	3,807	14	24	(17)	18	39
Related Taxes for Increase						
State & Federal Income Taxes	2,311	9	15	(10)	11	25
Total Increase in Revenue	6,118	23	39	(27)	29	64
Total Revenue Before Increase	186,308	1	19	59	12	91
Total Cost of Service Required from Rates	192,426	24	58	32	41	155
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	1	3	2	1	7
Revenue Required from Rates	182,917	23	55	30	40	148
Projected Rate of Return Before Increase	6.727%					(0.407%)
Projected Billing Units						
Kwh	2,014,529,000			1,267,000		
Kw Demand	3,304,802	8,085	8,085			
Bills	1,170,228				552	
Unit Cost of Service						
$ per Kwh				0.024		
$ per Kw Demand		2.84	6.80			
$ per Customer Per Month					72.46	

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

MONTANA-DAKOTA UTILITIES CO.
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Cost of Service by Component
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(000's)

	Total North Dakota	Large General Primary Rate 30 Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total LG Primary Rate 30
Rate Base	520,229	27,557	6,571	334	236	34,698
Operating Income for Proposed Return	38,805	2,055	490	25	18	2,588
Current Operating Income	34,998	(2,404)	2,116	3,229	17	2,958
Increase in Operating Income	3,807	4,459	(1,626)	(3,204)	1	(370)
Related Taxes for Increase						
State & Federal Income Taxes	2,311	2,710	(988)	(1,947)	1	(224)
Total Increase in Revenue	6,118	7,169	(2,614)	(5,151)	2	(594)
Total Revenue Before Increase	186,308	275	4,188	10,185	53	14,701
Total Cost of Service Required from Rates	192,426	7,444	1,574	5,034	55	14,107
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	275	83	254	4	616
Revenue Required from Rates	182,917	7,169	1,491	4,780	51	13,491
Projected Rate of Return Before Increase	6.727%					8.525%
Projected Billing Units						
Kwh	2,014,529,000			195,765,000		
Kw Demand	3,304,802	468,864	468,864			
Bills	1,170,228				516	
Unit Cost of Service						
$ per Kwh				0.024		
$ per Kw Demand		15.29	3.18			
$ per Customer Per Month					98.84	

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY
NORTH DAKOTA
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Projected 2017 - Reflecting Staff Recommended Adjustments
(000's)

	Total North Dakota	Large General Secondary Rate 30 Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total LG Secondary Rate 30
Rate Base	520,229	128,549	27,046	1,302	11,032	167,929
Operating Income for Proposed Return	38,805	9,588	2,017	97	823	12,525
Current Operating Income	34,998	(11,214)	13,350	13,110	533	15,779
Increase in Operating Income	3,807	20,802	(11,333)	(13,013)	290	(3,254)
Related Taxes for Increase						
State & Federal Income Taxes	2,311	12,643	(6,888)	(7,909)	176	(1,978)
Total Increase in Revenue	6,118	33,445	(18,221)	(20,922)	466	(5,232)
Total Revenue Before Increase	186,308	1,284	24,793	40,566	2,636	69,279
Total Cost of Service Required from Rates	192,426	34,729	6,572	19,644	3,102	64,047
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	1,284	336	990	159	2,769
Revenue Required from Rates	182,917	33,445	6,236	18,654	2,943	61,278
Projected Rate of Return Before Increase	6.727%					9.396%
Projected Billing Units						
Kwh	2,014,529,000			755,983,226		
Kw Demand	3,304,802	2,281,944	2,281,944			
Bills	1,170,228				55,044	
Unit Cost of Service						
$ per Kwh				0.025		
$ per Kw Demand		14.66	2.73			
$ per Customer Per Month					53.47	

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

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		TOD Large General Rate 31 Primary				Total
	Total North Dakota	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	TOD LG Primary Rate 31
Rate Base	520,229	292	85	4	6	387
Operating Income for Proposed Return	38,805	22	6	0	0	28
Current Operating Income	34,998	(25)	18	25	1	19
Increase in Operating Income	3,807	47	(12)	(25)	(1)	9
Related Taxes for Increase						
State & Federal Income Taxes	2,311	29	(7)	(15)	(1)	6
Total Increase in Revenue	6,118	76	(19)	(40)	(2)	15
Total Revenue Before Increase	186,308	3	40	92	1	136
Total Cost of Service Required from Rates	192,426	79	21	52	(1)	151
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	3	1	3	0	7
Revenue Required from Rates	182,917	76	20	49	(1)	144
Projected Rate of Return Before Increase	6.727%					4.910%
Projected Billing Units						
Kwh	2,014,529,000			2,081,000		
Kw Demand	3,304,802	3,954	3,954			
Bills	1,170,228				12	
Unit Cost of Service						
$ per Kwh				0.024		
$ per Kw Demand		19.22	5.06			
$ per Customer Per Month					(83.33)	

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

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	Total North Dakota	TOD Large General Rate 31 Secondary Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total TOD LG Seconda Rate 31
Rate Base	520,229	3,010	634	30	190	3,864
Operating Income for Proposed Return	38,805	225	47	2	14	288
Current Operating Income	34,998	(263)	313	206	4	260
Increase in Operating Income	3,807	488	(266)	(204)	10	28
Related Taxes for Increase						
State & Federal Income Taxes	2,311	297	(162)	(124)	6	17
Total Increase in Revenue	6,118	785	(428)	(328)	16	45
Total Revenue Before Increase	186,308	30	582	785	39	1,436
Total Cost of Service Required from Rates	192,426	815	154	457	55	1,481
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	30	7	23	1	61
Revenue Required from Rates	182,917	785	147	434	54	1,420
Projected Rate of Return Before Increase	6.727%					6.729%
Projected Billing Units						
Kwh	2,014,529,000			17,694,774		
Kw Demand	3,304,802	46,446	46,446			
Bills	1,170,228				816	
Unit Cost of Service						
$ per Kwh				0.025		
$ per Kw Demand		16.90	3.16			
$ per Customer Per Month					66.18	

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

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	Total North Dakota	Space Heating Rate 32 Demand Prod. & Trans.	Space Heating Rate 32 Demand Distribution	Space Heating Rate 32 Energy	Space Heating Rate 32 Customer	Total Space Heating Rate 32
Rate Base	520,229	6,858	2,836	96	282	10,072
Operating Income for Proposed Return	38,805	512	212	7	21	752
Current Operating Income	34,998	(597)	159	1,143	(6)	699
Increase in Operating Income	3,807	1,109	53	(1,136)	27	53
Related Taxes for Increase						
State & Federal Income Taxes	2,311	674	32	(690)	16	32
Total Increase in Revenue	6,118	1,783	85	(1,826)	43	85
Total Revenue Before Increase	186,308	69	591	3,282	118	4,060
Total Cost of Service Required from Rates	192,426	1,852	676	1,456	161	4,145
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	69	35	73	6	183
Revenue Required from Rates	182,917	1,783	641	1,383	155	3,962
Projected Rate of Return Before Increase	6.727%					6.940%
Projected Billing Units						
Kwh	2,014,529,000			55,941,000		
Kw Demand	3,304,802	273,550	273,550			
Bills	1,170,228				7,476	
Unit Cost of Service						
$ per Kwh				0.025		
$ per Kw Demand		6.52	2.34			
$ per Customer Per Month					20.73	

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

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	Total North Dakota	Small Municipal Rate 40 Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total Sm Municipal Rate 40
Rate Base	520,229	711	175	7	389	1,282
Operating Income for Proposed Return	38,805	53	13	1	29	96
Current Operating Income	34,998	(62)	18	80	11	46
Increase in Operating Income	3,807	115	(5)	(79)	18	50
Related Taxes for Increase						
State & Federal Income Taxes	2,311	70	(3)	(48)	11	29
Total Increase in Revenue	6,118	185	(8)	(127)	29	79
Total Revenue Before Increase	186,308	7	50	234	79	370
Total Cost of Service Required from Rates	192,426	192	42	107	108	449
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	7	1	5	4	17
Revenue Required from Rates	182,917	185	41	102	104	432
Projected Rate of Return Before Increase	6.727%					3.588%
Projected Billing Units						
Kwh	2,014,529,000			4,076,000		
Kw Demand	3,304,802	9,468	9,468			
Bills	1,170,228				3,708	
Unit Cost of Service						
$ per Kwh				0.025		
$ per Kw Demand		19.54	4.33			
$ per Customer Per Month					28.05	

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

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		Municipal Lighting Primary Rate 41				Total
	Total North Dakota	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Mun Lighting Pri Rate 41
Rate Base	520,229	114	82	3	28	227
Operating Income for Proposed Return	38,805	9	6	0	2	17
Current Operating Income	34,998	(9)	(5)	51	(2)	34
Increase in Operating Income	3,807	18	11	(51)	4	(17)
Related Taxes for Increase						
State & Federal Income Taxes	2,311	11	7	(31)	2	(12)
Total Increase in Revenue	6,118	29	18	(82)	6	(29)
Total Revenue Before Increase	186,308	1	0	126	0	127
Total Cost of Service Required from Rates	192,426	30	18	44	6	98
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	1	0	2	0	3
Revenue Required from Rates	182,917	29	18	42	6	95
Projected Rate of Return Before Increase	6.727%					14.978%
Projected Billing Units						
Kwh	2,014,529,000	1,719,000	1,719,000	1,719,000		
Kw Demand	3,304,802					
Bills	1,170,228					
Unit Cost of Service						
$ per Kwh		0.017	0.010	0.024		
$ per Kw Demand						
$ per Customer Per Month						

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

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	Total North Dakota	Municipal Lighting Secondary Rate 41 Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total Mun Lighting Sec Rate 41
Rate Base	520,229	1,139	1,278	31	2,192	4,640
Operating Income for Proposed Return	38,805	85	95	2	164	346
Current Operating Income	34,998	(100)	(82)	599	136	553
Increase in Operating Income	3,807	185	177	(597)	28	(207)
Related Taxes for Increase						
State & Federal Income Taxes	2,311	112	108	(363)	17	(126)
Total Increase in Revenue	6,118	297	285	(960)	45	(333)
Total Revenue Before Increase	186,308	11	16	1,434	645	2,106
Total Cost of Service Required from Rates	192,426	308	301	474	690	1,773
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	11	16	24	645	696
Revenue Required from Rates	182,917	297	285	450	45	1,077
Projected Rate of Return Before Increase	6.727%					11.918%
Projected Billing Units						
Kwh	2,014,529,000	18,127,000	18,127,000	18,127,000		
Kw Demand	3,304,802					
Bills	1,170,228					
Unit Cost of Service						
$ per Kwh		0.016	0.016	0.025		
$ per Kw Demand						
$ per Customer Per Month						

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

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		Municipal Pumping Primary Rate 48				Total
	Total North Dakota	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Mun Pumping Pri Rate 48
Rate Base	520,229	2,056	645	24	28	2,753
Operating Income for Proposed Return	38,805	153	48	2	2	205
Current Operating Income	34,998	(179)	67	189	0	77
Increase in Operating Income	3,807	332	(19)	(187)	2	128
Related Taxes for Increase						
State & Federal Income Taxes	2,311	202	(12)	(114)	1	77
Total Increase in Revenue	6,118	534	(31)	(301)	3	205
Total Revenue Before Increase	186,308	20	184	658	1	863
Total Cost of Service Required from Rates	192,426	554	153	357	4	1,068
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	20	8	18	0	46
Revenue Required from Rates	182,917	534	145	339	4	1,022
Projected Rate of Return Before Increase	6.727%					2.797%
Projected Billing Units						
Kwh	2,014,529,000			13,894,000		
Kw Demand	3,304,802	35,805	35,805			
Bills	1,170,228				48	
Unit Cost of Service						
$ per Kwh				0.024		
$ per Kw Demand		14.91	4.05			
$ per Customer Per Month					83.33	

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

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	Total North Dakota	Municipal Pumping Secondary Rate 48 Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total Mun Pumping Sec Rate 48
Rate Base	520,229	3,802	1,350	43	659	5,854
Operating Income for Proposed Return	38,805	284	101	3	49	437
Current Operating Income	34,998	(331)	281	375	(36)	289
Increase in Operating Income	3,807	615	(180)	(372)	85	148
Related Taxes for Increase						
State & Federal Income Taxes	2,311	374	(109)	(226)	52	91
Total Increase in Revenue	6,118	989	(289)	(598)	137	239
Total Revenue Before Increase	186,308	38	613	1,250	47	1,948
Total Cost of Service Required from Rates	192,426	1,027	324	652	184	2,187
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	38	16	33	10	97
Revenue Required from Rates	182,917	989	308	619	174	2,090
Projected Rate of Return Before Increase	6.727%					4.937%
Projected Billing Units						
Kwh	2,014,529,000			25,168,000		
Kw Demand	3,304,802	91,118	91,118			
Bills	1,170,228				3,828	
Unit Cost of Service						
$ per Kwh				0.025		
$ per Kw Demand		10.85	3.38			
$ per Customer Per Month					45.45	

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

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		Outdoor Lighting Rate 52				
	Total North Dakota	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total Outdoor Lighting Rate 52
Rate Base	520,229	747	389	13	635	1,784
Operating Income for Proposed Return	38,805	56	29	1	47	133
Current Operating Income	34,998	(66)	(27)	324	1	232
Increase in Operating Income	3,807	122	56	(323)	46	(99)
Related Taxes for Increase						
State & Federal Income Taxes	2,311	74	34	(196)	28	(60)
Total Increase in Revenue	6,118	196	90	(519)	74	(159)
Total Revenue Before Increase	186,308	8	4	715	209	936
Total Cost of Service Required from Rates	192,426	204	94	196	283	777
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	8	4	10	209	231
Revenue Required from Rates	182,917	196	90	186	74	546
Projected Rate of Return Before Increase	6.727%					13.004%
Projected Billing Units						
Kwh	2,014,529,000	7,437,000	7,437,000	7,437,000		
Kw Demand	3,304,802					
Bills	1,170,228					
Unit Cost of Service						
$ per Kwh		0.026	0.012	0.025		
$ per Kw Demand						
$ per Customer Per Month						

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

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	Total North Dakota	Interruptible Demand Response Rate 38 Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total IT Demand Response Rate 38
Rate Base	520,229	3,917	1,169	54	16	5,156
Operating Income for Proposed Return	38,805	292	87	4	1	384
Current Operating Income	34,998	(343)	286	432	10	386
Increase in Operating Income	3,807	635	(199)	(428)	(9)	(2)
Related Taxes for Increase						
State & Federal Income Taxes	2,311	386	(121)	(260)	(5)	1
Total Increase in Revenue	6,118	1,021	(320)	(688)	(14)	(1)
Total Revenue Before Increase	186,308	39	601	1,507	18	2,165
Total Cost of Service Required from Rates	192,426	1,060	281	819	4	2,164
Less: Other Operating Revenues (Incl Contract Revenue)	9,509	39	15	41	0	95
Revenue Required from Rates	182,917	1,021	266	778	4	2,069
Projected Rate of Return Before Increase	6.727%					7.486%
Projected Billing Units						
Kwh	2,014,529,000			31,911,000		
Kw Demand	3,304,802	85,568	85,568			
Bills	1,170,228				36	
Unit Cost of Service						
$ per Kwh				0.024		
$ per Kw Demand		11.93	3.11			
$ per Customer Per Month					111.11	

Operating Income/Inverse of Federal income tax rate:
Operating Income for Proposed Return:

MONTANA-DAKOTA UTILITIES CO.
RECOMMENDED REVENUE INCREASE ALLOCATION
REFLECTING RECOMMENDED REVENUE REQUIREMENTS FROM STAFF WITNESS R. POLICH
EXCLUSIVE OF RENEWABLE RIDER AND TRANSMISSION RIDER RECOMMENDED ADJUSTMENTS
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2017 ($000)

Line No.	Item	Total North Dakota	Total Residential	Total Small General	Total Large General	Total Lighting	Total Municipal Pumping
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Operating Revenues						
1	Sales Revenues	182,637	73,955	12,794	90,800	2,316	2,772
2	Other Revenues	3,671	1,585	217	977	853	39
3	Total Operating Revenues	186,308	75,540	13,011	91,777	3,169	2,811
	Operating Expense						
4	Cost of Fuel and Purchased Power	54,191	20,868	3,189	28,378	714	1,042
5	Other O&M Expense	52,325	25,454	4,141	21,131	792	807
6	Total O&M Expense	106,516	46,322	7,330	49,509	1,506	1,849
7	Depreciation Expense	24,746	11,648	1,884	10,467	345	402
8	Taxes Other Than Income Taxes	6,392	3,029	491	2,678	93	101
9	Current Income Taxes - Fed. & State	13,656	3,249	886	9,022	406	93
10	Total Operating Expenses	151,310	64,248	10,591	71,676	2,350	2,445
11	**Projected Operating Income**	34,998	11,292	2,420	20,101	819	366
12	**Rate Base**	520,229	243,214	39,651	222,106	6,651	8,607
13	Projected Rate of Return Before Revenue Inrease	6.727%	4.643%	6.103%	9.050%	12.314%	4.252%
14	Recommended Revenue Increase per Staff Witness R. Polich	515					
15	Percent Increase Over Current Sales Revenues	0.28%					
16	Maximum Increase (2.0 x System Increase)	0.56%					
17	Minimum Increase (0.5 x System Increase)	0.14%					
18	Recommended Revenue Allocation (% Increase)		0.43%	0.35%	0.15%	0.15%	0.55%
19	**Recommended Revenue Increase**	**515**	**316**	**45**	**136**	**3**	**15**
20	**Recommended Rate of Return After Increase**	**6.789%**	**4.724%**	**6.174%**	**9.088%**	**12.344%**	**4.357%**
21	**Recommended Relative Rate of Return (ND = 1.000)**	**1.000**	**0.696**	**0.909**	**1.339**	**1.818**	**0.642**

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PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2017 ($000)

TOTAL NORTH DAKOTA

	Before Additional Revenue Requirements	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$182,637	**$515**	$183,152
Sales for Resale			-
Other	3,671		3,671
Total Revenues	186,308	515	186,823
Operating Expenses			
Operation and Maintenance			
Cost of Fuel & Purchased Power	54,191		54,191
Other O&M	77,071		77,071
Total O&M	131,262		131,262
Depreciation			0
Taxes Other Than Income	6,392		6,392
Current Income Taxes	13,656	195	13,851
Deferred Income Taxes	0		0
Total Expenses	151,310	195	151,505
Operating Income	$34,998	$320	$35,318
Rate Base	$520,229		$520,229
Rate of Return	**6.727%**		**6.789%**

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PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2017 ($000)

TOTAL RESIDENTIAL

	Before Additional Revenue Requirements	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$73,955	**$316**	$74,271
Sales for Resale			-
Other	1,585		1,585
Total Revenues	75,540	316	75,856
Operating Expenses			
Operation and Maintenance			
Cost of Fuel & Purchased Power	20,868		20,868
Other O&M	37,102		37,102
Total O&M	57,970		57,970
Depreciation			0
Taxes Other Than Income	3,029		3,029
Current Income Taxes	3,249	119	3,368
Deferred Income Taxes	0		0
Total Expenses	64,248	119	64,367
Operating Income	$11,292	$197	$11,489
Rate Base	$243,214		$243,214
Rate of Return	**4.643%**		**4.724%**

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2017 ($000)

TOTAL SMALL GENERAL

	Before Additional Revenue Requirements	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$12,794	**$45**	$12,839
Sales for Resale			-
Other	217		217
Total Revenues	13,011	45	13,056
Operating Expenses			
Operation and Maintenance			
Cost of Fuel & Purchased Power	3,189		3,189
Other O&M	6,025		6,025
Total O&M	9,214		9,214
Depreciation			0
Taxes Other Than Income	491		491
Current Income Taxes	886	17	903
Deferred Income Taxes	0		0
Total Expenses	10,591	17	10,608
Operating Income	$2,420	$28	$2,448
Rate Base	$39,651		$39,651
Rate of Return	**6.103%**		**6.174%**

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PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2017 ($000)

TOTAL LARGE GENERAL

	Before Additional Revenue Requirements	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$90,800	**$136**	$90,936
Sales for Resale			-
Other	977		977
Total Revenues	91,777	136	91,913
Operating Expenses			
Operation and Maintenance			
Cost of Fuel & Purchased Power	28,378		28,378
Other O&M	31,598		31,598
Total O&M	59,976		59,976
Depreciation			0
Taxes Other Than Income	2,678		2,678
Current Income Taxes	9,022	51	9,073
Deferred Income Taxes	0		0
Total Expenses	71,676	51	71,727
Operating Income	$20,101	$85	$20,186
Rate Base	$222,106		$222,106
Rate of Return	**9.050%**		**9.088%**

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2017 ($000)

TOTAL LIGHTING

	Before Additional Revenue Requirements	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$2,316	**$3**	$2,319
Sales for Resale			-
Other	853		853
Total Revenues	3,169	3	3,172
Operating Expenses			
Operation and Maintenance			
Cost of Fuel & Purchased Power	714		714
Other O&M	1,137		1,137
Total O&M	1,851		1,851
Depreciation			0
Taxes Other Than Income	93		93
Current Income Taxes	406	1	407
Deferred Income Taxes	0		0
Total Expenses	2,350	1	2,351
Operating Income	$819	$2	$821
Rate Base	$6,651		$6,651
Rate of Return	**12.314%**		**12.344%**

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MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED 2017 ($000)

TOTAL MUNICIPAL PUMPING

	Before Additional Revenue Requirements	**Additional Revenue Requirements**	Reflecting Additional Revenue Requirements
Operating Revenues			
Sales	$2,772	**$15**	$2,787
Sales for Resale			-
Other	39		39
Total Revenues	2,811	15	2,826
Operating Expenses			
Operation and Maintenance			
Cost of Fuel & Purchased Power	1,042		1,042
Other O&M	1,209		1,209
Total O&M	2,251		2,251
Depreciation			0
Taxes Other Than Income	101		101
Current Income Taxes	93	6	99
Deferred Income Taxes	0		0
Total Expenses	2,445	6	2,451
Operating Income	$366	$9	$375
Rate Base	$8,607		$8,607
Rate of Return	**4.252%**		**4.357%**

MONTANA-DAKOTA UTILITIES CO.
BILLING COMPARISON AT VARIOUS USAGE LEVELS
RESIDENTIAL RATE 10

WINTER MONTH BILL, ASSUMING 30 BILLING DAYS
Present Rate vs. Proposed Rate with Declining Energy Block Charges

Line		Present Rate		Proposed Rate - Declining Block		Increase/(Decrease)	
No.	kWh Usage	Amount	¢ per kWh	Amount	¢ per kWh	Amount	Percent
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	0	$10.50	-	$19.50	-	$9.00	85.7%
2	50	$15.39	30.8	$24.30	48.6	$8.91	57.9%
3	100	$20.28	20.3	$29.11	29.1	$8.83	43.5%
4	200	$30.05	15.0	$38.71	19.4	$8.66	28.8%
5	300	$39.83	13.3	$48.32	16.1	$8.49	21.3%
6	400	$49.61	12.4	$57.92	14.5	$8.31	16.8%
7	500	$59.39	11.9	$67.53	13.5	$8.14	13.7%
8	600	$69.16	11.5	$77.14	12.9	$7.98	11.5%
9	700	$78.94	11.3	$86.74	12.4	$7.80	9.9%
10	800	$87.22	10.9	$94.85	11.9	$7.63	8.7%
11	900	$93.99	10.4	$101.45	11.3	$7.46	7.9%
12	1,000	$100.77	10.1	$108.06	10.8	$7.29	7.2%
13	1,200	$114.32	9.5	$121.27	10.1	$6.95	6.1%
14	1,250	$117.71	9.4	$124.58	10.0	$6.87	5.8%
15	1,500	$134.66	9.0	$141.09	9.4	$6.43	4.8%
16	1,750	$151.60	8.7	$157.61	9.0	$6.01	4.0%
17	2,000	$168.54	8.4	$174.12	8.7	$5.58	3.3%
18	2,500	$202.43	8.1	$207.15	8.3	$4.72	2.3%
19	3,000	$236.31	7.9	$240.18	8.0	$3.87	1.6%
20	3,500	$270.20	7.7	$273.21	7.8	$3.01	1.1%
21	4,000	$304.08	7.6	$306.24	7.7	$2.16	0.7%

RATE CHARGES

	Present Rates	Proposed Rates
Basic Service Charge	$0.35 per day	$0.65 per day
Energy Charges:		
First 750 kWh	$0.05304 per kWh	$0.06066 per kWh
Over 750 kWh	$0.02304 per kWh	$0.03066 per kWh
Generation Rider	$0.00500 per kWh	$0.00000 per kWh
Environmental Rider	$0.00396 per kWh	$0.00000 per kWh
Transmission Rider	$0.00329 per kWh	$0.00298 per kWh
Renewable Rider	$0.00712 per kWh	$0.00706 per kWh
Base Fuel & Purchased Power	$0.02536 per kWh	$0.02536 per kWh

MONTANA-DAKOTA UTILITIES CO.
BILLING COMPARISON AT VARIOUS USAGE LEVELS
RESIDENTIAL RATE 10

WINTER MONTH BILL, ASSUMING 30 BILLING DAYS
Present Rate vs. Proposed Rate with Flat Energy Charge

Line		Present Rate		Proposed Rate - Declining Block		Increase/(Decrease)	
No.	kWh Usage	Amount	¢ per kWh	Amount	¢ per kWh	Amount	Percent
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	0	$10.50	-	$19.50	-	$9.00	85.7%
2	50	$15.39	30.8	$23.72	47.4	$8.33	54.1%
3	100	$20.28	20.3	$27.94	27.9	$7.66	37.8%
4	200	$30.05	15.0	$36.38	18.2	$6.33	21.1%
5	300	$39.83	13.3	$44.82	14.9	$4.99	12.5%
6	400	$49.61	12.4	$53.26	13.3	$3.65	7.4%
7	500	$59.39	11.9	$61.70	12.3	$2.31	3.9%
8	600	$69.16	11.5	$70.14	11.7	$0.98	1.4%
9	700	$78.94	11.3	$78.58	11.2	($0.36)	-0.5%
10	800	$87.22	10.9	$87.02	10.9	($0.20)	-0.2%
11	900	$93.99	10.4	$95.46	10.6	$1.47	1.6%
12	1,000	$100.77	10.1	$103.90	10.4	$3.13	3.1%
13	1,200	$114.32	9.5	$120.78	10.1	$6.46	5.7%
14	1,250	$117.71	9.4	$125.00	10.0	$7.29	6.2%
15	1,500	$134.66	9.0	$146.10	9.7	$11.44	8.5%
16	1,750	$151.60	8.7	$167.20	9.6	$15.60	10.3%
17	2,000	$168.54	8.4	$188.30	9.4	$19.76	11.7%
18	2,500	$202.43	8.1	$230.50	9.2	$28.07	13.9%
19	3,000	$236.31	7.9	$272.70	9.1	$36.39	15.4%
20	3,500	$270.20	7.7	$314.90	9.0	$44.70	16.5%
21	4,000	$304.08	7.6	$357.10	8.9	$53.02	17.4%

RATE CHARGES

	Present Rates	Proposed Rates
Basic Service Charge	$0.35 per day	$0.65 per day
Energy Charges:		
First 750 kWh	$0.05304 per kWh	$0.04900 per kWh
Over 750 kWh	$0.02304 per kWh	$0.04900 per kWh
Generation Rider	$0.00500 per kWh	$0.00000 per kWh
Environmental Rider	$0.00396 per kWh	$0.00000 per kWh
Transmission Rider	$0.00329 per kWh	$0.00298 per kWh
Renewable Rider	$0.00712 per kWh	$0.00706 per kWh
Base Fuel & Purchased Power	$0.02536 per kWh	$0.02536 per kWh

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MONTANA-DAKOTA UTILITIES CO.
BILLING COMPARISON AT VARIOUS USAGE LEVELS
SMALL GENERAL SERVICE RATE 20

WINTER MONTH BILL, ASSUMING 30 BILLING DAYS
Present Rate vs. Proposed Rate with Declining Energy Block Charges

Line		Present Rate		Proposed Rate - Declining Block		Increase/(Decrease)	
No.	kWh Usage	Amount	¢ per kWh	Amount	¢ per kWh	Amount	Percent
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	0	$21.00	-	$25.20	-	$4.20	20.0%
2	50	$25.71	51.4	$30.43	60.9	$4.72	18.4%
3	100	$30.43	30.4	$35.65	35.7	$5.22	17.2%
4	200	$39.86	19.9	$46.11	23.1	$6.25	15.7%
5	300	$49.28	16.4	$56.56	18.9	$7.28	14.8%
6	400	$58.71	14.7	$67.02	16.8	$8.31	14.2%
7	500	$68.14	13.6	$77.47	15.5	$9.33	13.7%
8	600	$77.57	12.9	$87.92	14.7	$10.35	13.3%
9	700	$87.00	12.4	$98.38	14.1	$11.38	13.1%
10	800	$94.50	11.8	$107.33	13.4	$12.83	13.6%
11	900	$100.09	11.1	$114.79	12.8	$14.70	14.7%
12	1,000	$105.67	10.6	$122.24	12.2	$16.57	15.7%
13	1,200	$116.84	9.7	$137.15	11.4	$20.31	17.4%
14	1,250	$119.64	9.6	$140.88	11.3	$21.24	17.8%
15	1,500	$133.60	8.9	$159.51	10.6	$25.91	19.4%
16	1,750	$147.56	8.4	$178.15	10.2	$30.59	20.7%
17	2,000	$161.52	8.1	$196.78	9.8	$35.26	21.8%
18	2,500	$189.45	7.6	$234.05	9.4	$44.60	23.5%
19	3,000	$217.37	7.2	$271.32	9.0	$53.95	24.8%
20	3,500	$245.30	7.0	$308.59	8.8	$63.29	25.8%
21	4,000	$273.22	6.8	$345.86	8.6	$72.64	26.6%

RATE CHARGES

	Present Rates	Proposed Rates
Basic Service Charge	$0.70 per day	$0.84 per day
Energy Charges:		
First 750 kWh	$0.06147 per kWh	$0.07212 per kWh
Over 750 kWh	$0.02304 per kWh	$0.04212 per kWh
Generation Rider	$0.00349 per kWh	$0.00000 per kWh
Environmental Rider	$0.00396 per kWh	$0.00000 per kWh
Renewable Rider	$0.00000 per kWh	$0.00706 per kWh
Base Fuel & Purchased Power	$0.02536 per kWh	$0.02536 per kWh

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MONTANA-DAKOTA UTILITIES CO.
BILLING COMPARISON AT VARIOUS USAGE LEVELS
SMALL GENERAL SERVICE RATE 20

WINTER MONTH BILL, ASSUMING 30 BILLING DAYS
Present Rate vs. Proposed Rate with Flat Energy Charge

Line		Present Rate		Proposed Rate - Declining Block		Increase/(Decrease)	
No.	kWh Usage	Amount	¢ per kWh	Amount	¢ per kWh	Amount	Percent
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	0	$21.00	-	$25.20	-	$4.20	20.0%
2	50	$25.71	51.4	$29.65	59.3	$3.94	15.3%
3	100	$30.43	30.4	$34.10	34.1	$3.67	12.1%
4	200	$39.86	19.9	$42.99	21.5	$3.13	7.9%
5	300	$49.28	16.4	$51.89	17.3	$2.61	5.3%
6	400	$58.71	14.7	$60.79	15.2	$2.08	3.5%
7	500	$68.14	13.6	$69.69	13.9	$1.55	2.3%
8	600	$77.57	12.9	$78.58	13.1	$1.01	1.3%
9	700	$87.00	12.4	$87.48	12.5	$0.48	0.6%
10	800	$94.50	11.8	$96.38	12.0	$1.88	2.0%
11	900	$100.09	11.1	$105.27	11.7	$5.18	5.2%
12	1,000	$105.67	10.6	$114.17	11.4	$8.50	8.0%
13	1,200	$116.84	9.7	$131.96	11.0	$15.12	12.9%
14	1,250	$119.64	9.6	$136.41	10.9	$16.77	14.0%
15	1,500	$133.60	8.9	$158.66	10.6	$25.06	18.8%
16	1,750	$147.56	8.4	$180.90	10.3	$33.34	22.6%
17	2,000	$161.52	8.1	$203.14	10.2	$41.62	25.8%
18	2,500	$189.45	7.6	$247.63	9.9	$58.18	30.7%
19	3,000	$217.37	7.2	$292.11	9.7	$74.74	34.4%
20	3,500	$245.30	7.0	$336.60	9.6	$91.30	37.2%
21	4,000	$273.22	6.8	$381.08	9.5	$107.86	39.5%

RATE CHARGES

	Present Rates	Proposed Rates
Basic Service Charge	$0.70 per day	$0.84 per day
Energy Charges:		
First 750 kWh	$0.06147 per kWh	$0.05655 per kWh
Over 750 kWh	$0.02304 per kWh	$0.05655 per kWh
Generation Rider	$0.00349 per kWh	$0.00000 per kWh
Environmental Rider	$0.00396 per kWh	$0.00000 per kWh
Renewable Rider	$0.00000 per kWh	$0.00706 per kWh
Base Fuel & Purchased Power	$0.02536 per kWh	$0.02536 per kWh