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

400 North Fourth Street
Bismarck, ND 58501
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August 26, 2013

Executive Secretary
North Dakota Public Service Commission
State Capitol Building
Bismarck, ND 58505-0480

Re: Direct Testimony
Docket Nos. PU-13-83 and PU-13-85
OAH File No. 20130326

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. herewith submits an original and seven (7) copies of the Direct Testimonies and exhibits of Mr. Mark A. Rolfes, Mr. Mark Thoma, Ms. Andrea L. Stomberg, and Ms. Tamie A. Aberle pursuant to the Prehearing Conference Summary issued July 29, 2013 in the above-referenced dockets. Mr. Rolfes and Mr. Thoma are providing testimony on behalf of Otter Tail Power Company and Montana-Dakota and the identical testimony has been submitted by Otter Tail Power Company in Case Nos. PU-13-79 and PU-13-84.

Please acknowledge receipt by stamping or initiating the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Tamie A. Aberle
Director of Regulatory Affairs

Cc: Certificate of Service

CERTIFICATE OF SERVICE

In the Matter of the Application of Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., for Approval of an Environmental Cost Recovery Rider Tariff and Rate	)))))	**Case No. PU-13-83** **Case No. PU-13-85**

I, Caitlin Straabe, being first duly sworn on oath, deposes and says: that on the 26th day of August, 2013, I served the attached direct testimony on the North Dakota Public Service Commission by e-mail and regular mail and to all other persons listed below by email.

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Caitlin Straabe

Caitlin Straabe

Subscribed and sworn to before me this 26th day of August, 2013.

DENYS SCHWARTZ
Notary Public
State of North Dakota
My Commission Expires December 31, 2018

Denys Schwartz

Denys Schwartz, Notary Public
Burleigh County, North Dakota
My Commission Expires: 12/31/18

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE STATE OF NORTH DAKOTA

Otter Tail Power Company Environmental Cost Recovery Rider Tariff	)))	Case No. PU-13-79
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Environmental Cost Recovery Rider Rates	))))	Case No. PU-13-83
Otter Tail Power Company Environmental Cost Recovery Rider Rates	)))	Case No. PU-13-84
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Environmental Cost Recovery Rider Tariff	))))	Case No. PU-13-85

OAH File No. 20130326

DIRECT TESTIMONY

OF

MARK A. ROLFES, P.E.

ON BEHALF OF

OTTER TAIL POWER COMPANY

and MONTANA-DAKOTA UTILITIES CO.

August 26, 2013

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark A. Rolfes, P.E. My business address is 215 South Cascade Street, Fergus Falls, Minnesota 56537.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am the Manager, Generation Development for Otter Tail Power Company ("Otter Tail").

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND CURRENT RESPONSIBILITIES.

A. I have a Bachelor of Science Degree in Mechanical Engineering from North Dakota State University. I am a Professional Engineer licensed in Minnesota and South Dakota. I have worked in the power generation business for over 36 years and for Otter Tail for my entire professional career. I have particular experience with coal-fired generation as the manager of the Big Stone and the Hoot Lake coal-fired plants. I have also been extensively involved in the development of new power generation projects. I have served on the Governor's Citizens' Advisory Committee on Hazardous Waste Management in South Dakota and represented Otter Tail on numerous Electric Power Research Institute and Edison Electric Institute committees.

Currently, I am the project manager for the Big Stone Air Quality Control System ("AQCS") project, with overall responsibility for project development, construction, and

commissioning of the project. My main focus on the project is to supervise the engineering, construction, and commissioning work and assist with regulatory compliance activities.

Q. FOR WHOM ARE YOU PROVIDING TESTIMONY?

A. I am providing testimony on behalf of Otter Tail and Montana-Dakota Utilities, Co. ("Montana-Dakota").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to inform the Commission of the current status of the project and to explain why we believe the expenditures for the project are reasonable and prudent. In doing this I will update the Commission on the progress and explain changes in the budget and the project's current schedule.

Q. WOULD YOU BRIEFLY DESCRIBE THE BIG STONE PLANT?

A. The Big Stone Plant is located in Grant County, South Dakota. It is jointly owned by Otter Tail, NorthWestern Energy, and Montana Dakota. The plant went into commercial operation on May 1, 1975. It is a cyclone-fired unit that currently burns Powder River Basin coal and has a net output of 475 megawatts. Currently it uses a pulse jet fabric filter for control of particulates, a simple over-fire air system for nitrogen oxide control, and it has no controls for sulfur dioxide.

Q. BRIEFLY DESCRIBE THE AIR QUALITY CONTROL SYSTEM PROJECT AND THE TECHNOLOGY THAT IS BEING IMPLEMENTED.

A. The Air Quality Control System project is being installed on Big Stone to comply with the South Dakota State Implementation Plan ("SIP"). The South Dakota SIP is described in detail in Mr. Mark Thoma's Direct Testimony. Construction began on the project in late March 2013. The project consists of installing equipment for the control of sulfur dioxide, nitrogen oxide, particulate matter, and mercury. For the control of sulfur dioxide, an Andritz Environmental Solutions designed dry scrubber is being installed. The South Dakota SIP allows the installation of either semi-dry or dry technology for the sulfur dioxide removal. Through our evaluation and bidding process, we selected the dry technology. For the nitrogen oxide removal, we are installing a selective catalytic reduction unit ("SCR") that is being designed by engineering firm Sargent & Lundy and the catalyst is being provided by Haldor Topsoe, a catalyst vendor. Also a separated over-fire air ("SOFA") is being installed on the boiler and this is being designed by Babcock & Wilcox, the boiler manufacturer. For particulate control, the dry scrubber will be followed by a pulse jet fabric filter designed to handle the gas stream from the circulating dry scrubber. It is important to have the baghouse and the scrubber designed together because the ash flow into the baghouse from a circulating dry scrubber is much greater than from a semi-dry scrubber. The final piece of technology for the project is the activated carbon injection system that is being installed for the control of mercury. Activated carbon will be injected into the gas stream to collect mercury and it will be captured in the baghouse.

In addition to these technologies, all of the balance-of-plant supporting equipment necessary for this equipment to operate is being installed. This includes things such as two very large induced draft fans, all of the piping to support these systems, the electrical, fire protection, etc., to make all of these systems work together.

Q. CAN YOU EXPLAIN WHAT IS MEANT BY A CYCLONE-FIRED BOILER?

A. The prevalent design of the large utility size boilers is a pulverized coal-fired design. In the pulverized coal boilers, coal is ground into a fine powder and is then conveyed into the boiler with air and burned in a fire ball in the furnace area of the boiler releasing heat. A cyclone boiler is constructed differently. The actual combustion takes place in large cyclones or burners on the side of the boilers. These large burners are basically barrels sitting on their side that are approximately 10 feet in diameter with limited openings from the cyclones into the furnace. Coal is conveyed by air into one end of the cyclone where it spins violently and burns in the cyclone with the products of combustion then entering into the furnace. Because of this design, there are a number of advantages and disadvantages with the cyclone. The main advantage is that coal can be handled in larger size pieces, normally up to a quarter of an inch, as opposed to powder for a pulverized coal unit. Because of this it can also burn a wider variety of fuels. Cyclone boilers have been used to burn refuse, tire derived fuel, and biomass fuel. The cyclone design burns hotter so more of the ash will go out of the bottom of the cyclone in a molten state and there is less fly ash that goes up into the boiler. The main disadvantage of a cyclone

boiler is that combustion temperatures are much higher than a pulverized coal unit and this causes the production of higher amounts of nitrogen oxide.

Q. CAN YOU VERY BRIEFLY SUMMARIZE HOW THE PROJECT IS PROGRESSING?

A. The project is currently on schedule and on budget. Construction started in late March 2013. Commercial Operation is scheduled for October 1, 2015.

Q. CAN YOU SUMMARIZE WHAT HAS HAPPENED FROM THE TIME THAT THE ADVANCED DETERMINATION OF PRUDENCE WAS APPROVED AND UP TO THE DATE THIS TESTIMONY IS BEING FILED?

A. Following the approval of the Advanced Determination of Prudence by the North Dakota Commission, critical vendors were given a full notice to proceed. This fully engaged their design and eventually their manufacturing capabilities. Since that time, we have continued the detailed design engineering and procurement of materials. Today, almost all procurements are under contract. Over half of the material for the project has been received on site. Our general work contractor, Graycor, was selected. They mobilized and began on site work late in March 2013. To date, they have concentrated on foundation work and have started erecting the first structural steel. Graycor is a well-known contractor for projects of this type. For example, they served as contractor on an AQCS project for Xcel Energy's Allen S. King Plant and Alliant Energy's Edgewater Plant.

Q. WHAT IS THE MOST SIGNIFICANT PROCUREMENT THAT WAS COMPLETED DURING THIS TIME FRAME?

A. The most significant procurement was the selection and completing the contract for Graycor, the general work contractor. The general work contractor is the entity that is responsible for buying all of the material that the owners do not provide. This includes things such as concrete, small bore piping, and miscellaneous steel. The general work contractor is also responsible for erecting all of the equipment, structures, and facilities with the exception of the work on the boiler. The work on the boiler is performed under a separate contract that we have entered into with Babcock & Wilcox, the original boiler manufacturer. The general work contract was completed in January 2013, and the contractor mobilized in March.

Q. CAN YOU BRIEFLY OUTLINE WHAT IS EXPECTED TO HAPPEN ON THE PROJECT FOR THE PERIOD FROM NOW UNTIL THE PROJECT IS IN COMMERCIAL OPERATION?

A. We will be completing the foundation work this fall. Structural steel erection has already commenced. We will be continuing with structural steel erection through the fall and into winter. Erection of the baghouse has just started and will also continue. Construction will continue through all of 2014. Late in 2014 systems will start to be turned over to Otter Tail for checkout and commissioning in preparation for startup. In approximately March 2015, the unit will come off line for a three-month period. During

that period, the new SCR and FGD system will be tied in, that is physically connected to the existing unit. This requires the old duct work to be demolished and replaced with new. Also, the final control system tie-ins and needed boiler work will be done. We will go through the final commissioning checkout and startup, and when the unit returns to service, we will begin the startup and tuning of the equipment. We will then go through testing to verify that the equipment is performing as designed. Warranty periods will begin and the intention is that in the late fall of 2015 the equipment will be turned over for commercial operation.

Q. IS THE COMMISSION BEING APPRISED OF PROGRESS ON THE PROJECT?

A. Yes. As part of the Commission's Order approving Advanced Determination of Prudence for the project, Otter Tail and Montana-Dakota are required to file periodic progress reports with the Commission. The most recent report was filed on July 12, 2013.

Q. WHAT WAS THE PROJECTED COST FOR THE AQCS SYSTEM, INCLUDING THE ACTIVATED CARBON INJECTION, AT THE TIME OF THE ADVANCED DETERMINATION OF PRUDENCE HEARING?

A. At the time of the hearing, the projected cost at completion was approximately $489 million dollars. Later the regulations for mercury control were finalized and Activated Carbon Injection ("ACI") was added to the project. This increased the projected cost to approximately $491 million dollars. At the time of the hearing we had estimated the

stand alone cost for an ACI system at approximately $5 million dollars, but by doing it in conjunction with the AQCS we estimated an increase in cost of only $2.1 million dollars to the total project costs. Completion is in 2015, thus the projection included escalation of costs.

Q. HAS THIS PROJECTION CHANGED?

A. Yes, it has.

Q. WHAT IS THE CURRENT PROJECTION?

A. The current projection of cost at completion of the project is $405 million dollars, which is a reduction of approximately $86 million dollars from the projection at the time of the Advanced Determination of Prudence hearing.

Q. WHY HAS THERE BEEN A CHANGE IN THE PROJECTION OF COST ESTIMATES FOR THE PROJECT?

A. At the end of 2012, we were at a position in the project where most of the procurement activity was completed and much of the project was under contract. This gave us more information about actual costs than we had when the budget was put together. For that reason, we did a re-budgeting of costs considering all of the known contracts and revised projections of future costs. Based on that knowledge, we submitted a revised budget to the owners on March 1, 2013, which they subsequently approved.

Q. CAN YOU ELABORATE ON WHY THE ESTIMATED COST IS PROJECTED TO BE CONSIDERABLY LOWER?

A. The $86 million reduction, or approximately 17.5% of the original budget, is attributable to several things, but mainly four large categories for which costs have changed. The first category, which accounts for approximately 45% of the reduction, is a consequence of changes in the design of the equipment. As we began detailed design work, we worked very hard to find cost-effective changes to design that would not adversely affect the performance or operability of the system. For example, we were able to make slight changes in the boiler performance requirements that allowed us to eliminate planned modifications to the economizer hopper area. This resulted in considerable savings. Another example is that we were able to engineer a way to use the existing 13.8 kV switchgear for the Plant instead of adding additional switchgear equipment. Because of this change, we were able to eliminate a separate substation feed for the project, and this eliminated the need for a 230 kV tie to the existing substation and a separate substation that included transformers and breakers. This and other engineering work has allowed us to save money by a more efficient design.

The next major category of cost reduction relates to the project delivery method, timing, and market conditions. These factors account for about 35% of the cost reduction. As stated in the ADP, we are currently in what could be referred to as a "buyer's market." We have a number of vendors that are very interested in supplying much of the equipment and material for the project. To take advantage of this timing, the Plant

owners chose a single general work contractor approach as the project delivery method (other possible methods would have been Engineer, Procure & Construct ("EPC"), multiple prime contracting, etc.). Using a single work contractor approach, with a target pricing concept, allows us to get to the market sooner and, consequently, we have seen reduced prices for material and services.

The third category of cost savings, which accounts for approximately 13% of the cost projection reduction, is the result of the Big Stone owners' approach to project construction management. After selecting a project delivery method that uses a single general work contractor, the owners agreed that Otter Tail could serve as the construction manager rather than contracting with a third party to do that work. By Otter Tail taking on the construction manager role, the Plant owners were able to further reduce costs.

The fourth category of cost reduction is a consequence of the reduction in overall project costs. Because of the overall reductions, the contingency amount for the project is also reduced; this reduction accounts for about 7 percent of the budget reduction.

Q. IN THE PREVIOUS ANSWER YOU SAID THAT A "TARGET PRICING" CONCEPT ALLOWED YOU TO GET TO THE MARKET EARLIER. PLEASE EXPLAIN WHAT TARGET PRICING IS AND HOW IT ALLOWED YOU TO GET TO THE MARKET EARLIER, AS WELL AS ANY OTHER ADVANTAGES TO THIS APPROACH.

A Target pricing is the concept that at the time of bidding, engineering design is not completely done. The contractors will bid on quantities of work based on design at the time of bid release. Each quantity will have a unit price. Then at the actual issuing of drawings for construction ("IFC"), the difference is trued up based on the unit pricing for the difference between the issue for bid and IFC. This allows going to the market before design is complete. The total contract price is then referred to as a target price. The contractor then has an incentive or penalty associated with actual cost being above or below the target price. There is a graduated sharing of the risk and reward depending on the difference from the target price. There is a cap on the owners' sharing of the risk side of the equation. This provides an incentive for the contractor to efficiently use his labor and material at the same time it reduces the level of contingency a contractor needs to include in its bid. It also caps the owners' liability for overruns.

Q. YOU INDICATED THAT OTTER TAIL WILL SERVE AS THE CONSTRUCTION MANAGER. DOES OTTER TAIL HAVE THE CAPABILITIES TO SUCCESSFULLY MANAGE CONSTRUCTION OF THIS LARGE PROJECT?

A. Historically, Otter Tail has not done this type of management effort, but because of the careful selection of the single general work contractor and the quality of the project team that we have put together, the Big Stone owners agreed that Otter Tail is capable to successfully manage this project. To ensure Otter Tail's project management team has the depth of experience and expertise appropriate to successfully manage the project, the

project team is comprised of approximately 50 percent Otter Tail employees and 50 percent contractors. The Otter Tail employees bring many years of operating and plant experience, plus knowledge of the project owners and the area. For the remaining personnel we contracted with numerous service providers to bring into the management team specific individuals with the necessary project management expertise. The project management team has been very fortunate to get a number of individuals with many years of construction management experience. By blending our talents and their talents, we have formed a team that is well positioned to successfully manage this project.

Q. CAN YOU BRIEFLY EXPLAIN HOW RISK IS MANAGED FOR THE AQCS PROJECT?

A. Good project management is largely about the mitigation and management of risk. In the case of a large project like the AQCS project, we have taken the approach of first identifying potential risks. For example, there are risks associated with the uncertainty of labor availability, quality of labor, and availability of certain materials. There are also many typical project-related risks such as the risk of casualty losses and contractor performance risks. Our risk management approach includes the evaluation of reasonable measures that can be taken to eliminate or transfer those risks when possible; and for the risks that can't reasonably be eliminated or transferred, the project management team considers what measures can be taken to mitigate or otherwise manage those risks.

With respect to risks associated with market conditions, we constantly monitor market conditions to respond proactively on our procurements. So far we've been very successful in doing that. Another risk is the availability and quality of the labor. This is a risk that we cannot completely mitigate, but we have taken efforts to be in contact very early with potential suppliers and with the trade organizations to monitor their work load and the availability of labor, and to make sure that our project is part of their planning. We continue to work with them to mitigate these labor-related risks wherever possible.

In our procurements for the project, there is a separate risk analysis done for each major procurement. We look at the risk exposures associated with each contract. Commercially reasonable terms are negotiated to address contractor performance, liability, indemnification, insurance requirements, and other aspects of risk associated with the transaction. In all of our major contracts we have included liquidated damages provisions as part of those contracts. These provisions do not entirely eliminate contract-related risks, but they provide a commercially reasonable incentive for vendors to manage risks within their control. Additional contractual provisions are considered that may, in appropriate circumstances, transfer other risks to the contract vendor. For example, we've endeavored to have vendors retain the responsibility for labor and commodity price escalation by providing a firm price for the work or material they are supplying.

Our risk management efforts also employ insurance products. As I mentioned, our contracts contain terms with appropriate insurance requirements for suppliers and vendors. The project has also procured builder's risk insurance to cover the construction. We have worked with Willis, the insurance advisors who have historically assisted the Plant owners in the procurement of appropriate insurance products. With the assistance of Willis, we have evaluated the cost effectiveness of various insurance products that could cover risks associated with the project. One cost-effective solution we developed was to take builder's risk insurance from the same provider as the property insurance provider for the existing plant. This accomplished two things: it prevented a double deductible if there was an incident caused by the project's builder that affected the existing operating plant; and, by having the same insurance carrier, it eliminated the possibility that the property insurer and the builder's risk insurer might dispute accountability for a covered loss.

To summarize our risk management approaches, generally, we identify risks and then summarize and evaluate the risks to assess the owners' options for eliminating, transferring, mitigating or managing the risks. The risk summary is reviewed monthly for any change condition. We monitor market conditions carefully and respond appropriately to mitigate risks associated with labor availability, quality of labor, and availability of certain materials. We negotiate with our contractors and suppliers to arrive at commercially reasonable contract terms, and we utilize cost-effective and commercially reasonable insurance products to further cover project risk exposures. As

indicated, it is not possible to eliminate or transfer all risks for a project of this size, complexity, and duration. Our approaches to risk management provide a commercially reasonable approach to mitigate and manage those risks that cannot be eliminated or transferred in their entirety.

Q. IS PROCUREMENT OF MATERIALS AND SERVICES A LARGE PORTION OF THE COST OF THE PROJECT?

A. Yes, it is over 70% of the entire project cost.

Q. BECAUSE THESE PROCUREMENTS MAKE UP SUCH A LARGE SHARE OF THE PROJECT COST, WHAT EFFORTS AND MEASURES ARE TAKEN TO ENSURE THAT PROCURED PRODUCTS AND SERVICES ARE REASONABLY PRICED?

A. Our procurements began with the hiring of Sargent & Lundy to be our project engineer. The selection was done on a competitive basis with proposals from a number of major engineering firms. As part of the evaluation process, similar projects to ours done by engineering firms were visited and we talked directly to the owners of those projects to get feedback on the performance of their selected engineers. Though all firms evaluated were reputable and capable of doing this project, Sargent & Lundy was selected because of cost and experience. Sargent & Lundy has done more of these projects than any other firm and provided a lower cost. Since hiring Sargent & Lundy, major procurements have been a joint effort between Otter Tail's strategic sourcing department, Sargent & Lundy's

procurement department and Nixon Peabody, a law firm with extensive experience in project procurements.

With the exception of the distributed control system for the facility, all procurements have been made through a bidding process. Because the project will be integrated into an existing computer control system, the distributed control system was a sole sourced procurement. For all other procurements, detailed specifications and terms and conditions were assembled for vendor solicitations. The bids were analyzed for cost, technical performance, and commercial terms.

Q. CAN YOU PROVIDE A DETAILED EXPLANATION OF ONE OF THE LARGER PROCUREMENTS?

A. A good example of one of our procurements is the general work contract. As I indicated earlier, this is the largest contract for the project. As outlined before, detailed specifications were put together for this contract. When it was completed, the specifications and contract language were approximately 2,100 pages. Work on this contract began more than a year in advance of it being let for proposals. It began by putting together a long list of potential bidders. We then evaluated these vendors for their capability and experience and came up with a shorter list of seventeen companies. From these seventeen companies, we solicited additional information to further reduce the list. This information included their experience, their safety record, their financial strength, etc. From this list we then narrowed it down to seven potential bidders and later down to

six because of the inability of one of the contractors to completely bond the project. After we had the list of six, all vendors came in and provided presentations on how they would address our project. After these presentations, the request for proposals were submitted and bids were received. All bids were evaluated for their cost, their technical issues, and commercial terms. We then brought in all vendors individually to make presentations and answer questions on their proposals. From that, the lowest evaluated cost bidder was selected and we began negotiations for commercial and technical issues with them, resolved open issues, and entered into a contract. This process took over one year.

Q. IS THIS TYPICAL OF ALL THE OTHER CONTRACTS.

A. This was a more expansive process because it was for the largest contract related to the project, but the basic activities described have also been followed for the other contracts.

Q. ALONG WITH CONSTRUCTION MANAGEMENT, THERE IS THE STARTUP AND COMMISSIONING EFFORT. HOW IS OTTER TAIL PROPOSING TO HANDLE THE STARTUP AND COMMISSIONING?

A. The startup and commissioning portion of the project is being handled in a very similar way to the construction management. We are looking for management for this effort to come from the existing core group that is managing the construction effort. Then the people to accomplish this will again be a mixture of Otter Tail employees, plant employees, and outside contractors. The plant employees provide the knowledge of the

integration of this equipment and the outside contractors have the construction commission experience that we do not have.

Q. IS THIS ORGANIZATION IN PLACE?

A. We are well into establishing this organization though it is not complete. We have contracted with Sargent & Lundy to provide key experience field people and we are working with the Plant to identify the staffing resources. We hope to have this organization determined by the end of 2013. Early 2014 will be spent in preparation with the team actually being formed at the end of summer 2014 to begin the commissioning work as systems are completed.

Q. CAN YOU BRIEFLY SUMMARIZE YOUR TESTIMONY?

A. The current Big Stone AQCS project is on schedule and on budget. The budget has been reduced by $86,000,000 to $405,000,000. We have a long way to go, but the project is on track and is being managed consistent with prudent utility practice. The expenditures are being done in a prudent and reasonable manner in the best interest of our customers. We have evaluated the risk for the project and are appropriately mitigating and managing those risks. We have procured equipment, material, and services in a competitive manner and have established procedures and monitoring to insure that the project continues on course and on plan and have knowledge of where we are so corrective actions can be taken if situations arise.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE STATE OF NORTH DAKOTA

Otter Tail Power Company Environmental Cost Recovery Rider Tariff	)))	Case No. PU-13-79
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Environmental Cost Recovery Rider Rates	))))	Case No. PU-13-83
Otter Tail Power Company Environmental Cost Recovery Rider Rates	)))	Case No. PU-13-84
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Environmental Cost Recovery Rider Tariff	))))	Case No. PU-13-85

OAH File No. 20130326

DIRECT TESTIMONY

OF

MARK THOMA

ON BEHALF OF

OTTER TAIL POWER COMPANY

and MONTANA-DAKOTA UTILITIES COMPANY

August 26, 2013

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark Thoma. My business address is 215 South Cascade Street, Fergus Falls, Minnesota 56537.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am the Manager, Environmental Services for Otter Tail Power Company ("Otter Tail" or the "Company").

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I am a native of Fergus Falls, Minnesota, and graduated in 2001 from the University of North Dakota with a Bachelor of Science Degree in Chemical Engineering. Shortly thereafter I began my employment with Otter Tail, providing environmental compliance support in Otter Tail's Environmental Services Department. My primary responsibilities were in the area of air quality, including review and implementation of environmental regulations, development of compliance strategies, data collection, and development of permit applications. I was given additional responsibilities within the Department in 2006 as a Senior Compliance Specialist, and in 2011 as Principal, Environmental Services. In 2012, I was named Manager of the Environmental Services Department, which is my current role. Prior to being named Manager, I worked closely with Terry Graumann, the former Manager of the Environmental Services Department, who had been employed with Otter Tail for over 38 years.

Q. FOR WHOM ARE YOU PROVIDING TESTIMONY?

A. I am providing testimony on behalf of Otter Tail and Montana-Dakota Utilities Co. ("Montana-Dakota").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony is offered to describe the regulations that require the implementation of the Air Quality Control System ("AQCS") at Big Stone Plant.

Q. PLEASE DESCRIBE THE REGIONAL HAZE RULE AND THE BIG STONE PLANT OWNERS' OBLIGATIONS CREATED BY THE RULE.

A. The underlying need to install the AQCS dates back to the 1977 amendments to the federal Clean Air Act (42 U.S.C. §7479). At that time Congress added Section 169A to set forth a national goal of preventing and remedying impairment of visibility from man-made air pollution in Class I areas of the United States. These Class I areas include the Theodore Roosevelt National Park and Lostwood National Wildlife Refuge in North Dakota. In 1990, Congress amended the Clean Air Act to strengthen and reaffirm the national goal. In response to these Clean Air Act mandates, the Environmental Protection Agency ("EPA") promulgated the Regional Haze Rule in 1999 (40 CFR Part 51 Subpart P). The Regional Haze Rule requires state environmental agencies to submit State Implementation Plans ("SIP") that reduce emissions contributing to regional haze and establish benchmarks toward meeting the goal of no man-made visibility impairment in Class I areas by 2064. The Clean Air Act and the Regional Haze Rule require electric

generating units placed into operation between 1962 and 1977, like the Big Stone Plant which began commercial operation on May 1, 1975, to install and operate Best Available Retrofit Technology ("BART") if a unit is reasonably anticipated to cause or contribute to visibility impairment in a Class I area.

Q. IS THE AQCS PROJECT AT THE BIG STONE PLANT BEING INSTALLED TO MEET THE REGIONAL HAZE RULE BART REQUIREMENTS?

A. Yes. The requirement to install the AQCS equipment was discussed at length in Otter Tail's and Montana-Dakota's Applications for Advance Determination of Prudence ("ADP") that were granted with certain conditions by the North Dakota Public Service Commission on May 9, 2012 (Case Nos. PU-11-163 and PU-11-165). As described in those proceedings, the AQCS equipment is required by the final South Dakota Regional Haze SIP that was approved by the EPA and required under the Administrative Rules of South Dakota (ARSD) chapter 74:36:21:07. EPA's final approval of the South Dakota Regional Haze SIP was published in the Federal Register on April 26, 2012.

Q. BY WHAT DATE WILL THE AQCS NEED TO BE INSTALLED AT THE BIG STONE PLANT?

A. The Big Stone Plant owners are required to install the AQCS as expeditiously as practicable, but no later than five years from EPA's approval of the South Dakota Regional Haze SIP, or April 26, 2017.

Q. WHAT WOULD THE CONSEQUENCE BE IF THE BIG STONE PLANT OWNERS DID NOT INSTALL THE BART-REQUIRED AQCS EQUIPMENT?

A. The owners would have to discontinue operation of the plant on or before April 26, 2017.

Q. HOW WAS IT DETERMINED THAT THE BIG STONE PLANT CAUSES OR CONTRIBUTES TO VISIBILITY IMPAIRMENT IN A CLASS I AREA?

A. This was a considerable effort. The Western Regional Air Partnership ("WRAP") first performed modeling on behalf of the South Dakota Department of Environment and Natural Resources ("DENR") in 2007. WRAP is a collaborative effort of state governments (including the South Dakota DENR and North Dakota Department of Health), tribal governments, and various federal agencies that was established to coordinate activities associated with the management of regional haze, visibility, and other air quality issues in the western United States. The WRAP modeling determined that Big Stone Plant would be reasonably anticipated to contribute to visibility impairment in several Class I areas. After Otter Tail was notified of the results, Otter Tail retained the Burns & McDonnell engineering firm and outside counsel from the Hunton & Williams law firm to acquire and review the WRAP modeling files. Otter Tail identified several errors in the modeling that caused Otter Tail to question the accuracy of the WRAP determination. After sharing Otter Tail's concerns with the DENR, the DENR agreed that Otter Tail should be allowed to re-run the models using the correct modeling inputs.

The initial modeling on behalf of Otter Tail was conducted by Burns & McDonnell, but it soon became apparent that the modeling complexities and the extended model run turn-around time required a cutting-edge approach and increased computer capability. Consequently, Joseph Scire of TRC Environmental Corporation ("TRC") was selected for the modeling effort in late November 2007. Joseph Scire is a respected air dispersion modeler who developed CALPUFF, which is the long-range transport air quality dispersion modeling system adopted by EPA for BART assessments. After nearly a two-year period in which Otter Tail retained TRC and Hunton & Williams to perform modeling iterations and negotiate with the DENR, EPA, and Federal Land Managers, on September 18, 2009, the DENR approved a modeling protocol that was agreeable to all parties. TRC subsequently conducted the modeling on behalf of Otter Tail, and Otter Tail submitted a final modeling report to the DENR on October 12, 2009. The modeling results indicated that Big Stone Plant contributed to visibility impairment at the Badlands National Park in South Dakota, Theodore Roosevelt National Park in North Dakota, Isle Royale National Park in Michigan, and Voyagers National Park and the Boundary Waters Canoe Area in Minnesota. Whether there was a contribution to visibility impairment was determined by visibility impacts greater than 0.5 deciviews based on the 98th percentile of the data values. Consequently, Big Stone Plant was required to install and operate BART.

Q. WHO DETERMINES WHAT IS BART?

A. As specified by Section 169A of the Clean Air Act, states are responsible for determining BART. If a state fails to make a required submission or EPA determines that a state plan is deficient, EPA will promulgate a Federal Implementation Plan ("FIP"). The South Dakota DENR has general legal authority under South Dakota Codified Laws Title 34A-1 (Air Pollution Control) to adopt and enforce rules for visibility protection, including regional haze visibility impairment.

Q. WHAT WAS THE SOUTH DAKOTA DENR'S PROCESS FOR DETERMINING BART?

A. The DENR's BART determination process is described in detail in Section 6.3 of their Regional Haze SIP that was included within Attachment 1 to Otter Tail's Application for an Advance Determination of Prudence in NDPSC Case No. PU-11-165 and Montana-Dakota's Advance Determination of Prudence in NDPSC Case No. PU-11-163. To summarize, the DENR generally followed the five basic steps of EPA's BART guidelines given in Appendix Y in 40 CFR Part 51 that were promulgated on July 6, 2005. These steps are: (1) Identify all available retrofit technologies; (2) Eliminate technically infeasible options; (3) Evaluate control effectiveness of remaining control technologies; (4) Evaluate impacts and document the results; and (5) Evaluate Visibility Impacts. Within Step 4, the costs of compliance, energy and non-air quality environmental impacts, and remaining useful life of the source are considered.

Q. HOW IS COST EFFECTIVENESS DEFINED?

A. Under the BART guidelines, cost effectiveness is determined by dividing the estimated annualized cost of the technology by the identified emissions reductions that will be achieved. Therefore, cost effectiveness is a dollar-per-ton metric.

Q. WHAT WAS DETERMINED TO BE BART FOR THE BIG STONE PLANT?

A. The South Dakota DENR determined the following control technology constitutes BART for the Big Stone Plant: a Selective Catalytic Reduction ("SCR") in conjunction with separated over-fire air ("SOFA") for control of nitrogen oxides ("NOx"), a scrubber for reducing sulfur dioxide ("SO2"), and a baghouse to control particulate matter. The AQCS project, as described in Mr. Rolfes' Direct Testimony, consists of the control technology identified as BART by the South Dakota DENR.

Q. IN GENERAL, ARE THERE CHARACTERISTICS OF BIG STONE PLANT FACTORED INTO THE BART DETERMINATION?

A. Yes. Because the BART determination is specific to the Big Stone Plant, its particular design and operational characteristics are important to the BART determination. For example, the Big Stone Plant burns subbituminous coal and it is a cyclone boiler. These were especially important characteristics for the NOx determination because, in contrast to lignite coal, SCR is a feasible technology for subbituminous coal. Being a cyclone boiler is also important because the inherent design of these boilers typically results in higher baseline levels of NOx as compared to pulverized coal ("PC") boilers.

Q. WHY IS SCR NOT FEASIBLE FOR LIGNITE BUT IT IS FOR SUBBITUMINOUS?

A. Key differences include much higher sodium and ash levels in North Dakota lignite compared to most subbituminous coals. These characteristics of lignite make the catalyst susceptible to blinding and plugging, thereby preventing the catalyst's ability to reduce NOx emissions. One can review the development of North Dakota's Regional Haze SIP for an expert discussion on this phenomenon. Dr. Michael Jones, Vice President of Research and Development at the Lignite Energy Council, also described this phenomenon at a May 15, 2013 public hearing in which EPA was taking comments on portions of the North Dakota SIP that are being reconsidered (see docket ID EPA-R08-OAR-2010-0406-0382 transcript of public hearing at www.regulations.gov).

Q. WERE OTHER NOx CONTROL TECHNOLOGIES EVALUATED FOR BIG STONE PLANT?

A. Yes. Including SCR, the DENR determined that six technologies were feasible. Of those six, the DENR determined that only three technologies – SCR, Rich Reagent Injection ("RRI"), and Selective Non-Catalytic Reduction ("SNCR") – could reduce NOx emissions sufficiently for Big Stone Plant to not reasonably contribute to visibility impairment at Class I areas.

Q. COULD YOU BRIEFLY EXPLAIN THE DIFFERENCES BETWEEN SCR, SNCR, AND RRI?

A. The principle of SNCR and RRI is similar to SCR, which is described in Mr. Rolfes' Direct Testimony, in that ammonia is injected to reduce nitrogen oxides to molecular nitrogen and water. However, as the name implies, a catalyst is not used in SNCR. The ammonia is instead injected into a specific high temperature region of the boiler. Without the catalyst, SNCR is not able to achieve the same level of NOx reductions as SCR. RRI is similar to SNCR in that it injects ammonia into specific locations in the boiler without a catalyst, but RRI adds additional injection points. RRI is normally installed in conjunction with SNCR and combustion modifications and can achieve lower NOx emissions than just installing SNCR, but RRI uses a large amount of ammonia in comparison to either SCR or just SNCR.

Q. PLEASE GIVE SOME DETAIL ON HOW THE DENR SELECTED SCR AS BART OVER SNCR AND RRI.

A. As the DENR was comparing all of the BART factors, there were no significant differences among the alternatives in regard to energy and non-air quality environmental impacts, and in remaining useful life of the source. However, there were differences in the cost effectiveness and the degree of visibility improvement expected between the technologies. Due to the fact that the cost effectiveness of all of the control options was less than $900 per ton, the DENR determined all the identified control options were cost effective on a dollars-per-ton basis. (South Dakota SIP at page 102). Finally, based on

the visibility modeling, SCR reduces Big Stone Plant's visibility impact more than the other control options, including "an additional 34 percent over the second ranked control option." (Ibid.) Therefore, the DENR considered BART to be SCR.

Q. IS THERE ANY OTHER WAY TO EVALUATE THE REASONABLENESS OF THE DENR'S DETERMINATION THAT SCR WAS COST EFFECTIVE?

A. Yes. While many states did not set a specific threshold as to what they determined to be cost effective, for comparison, the North Dakota Department of Health did establish a ceiling of $3650 per ton (in 2006 dollars). North Dakota's cost threshold was included in a Commission Staff memo from Mr. Mark Grumann, attached as Exhibit _____ (MT-1). That memo contained copy of an email that Terry Graumann received from Mr. Tom Bachman, who is a senior engineer with the North Dakota Department of Health. Mr. Bachman indicates that based on the cost effectiveness that was presented for the Big Stone Plant SCR, it would be the North Dakota Department of Health's view that the SCR would have been economically feasible based on the cost effectiveness threshold used for North Dakota's BART assessments.

Additionally, Exhibit ____ (MT-2) is a table I compiled comparing the various BART determinations and associated BART cost effectiveness for South Dakota, North Dakota, Montana, Minnesota, and Wyoming.

Q. COULD YOU PLEASE STEP THROUGH EXHIBIT ____ (MT-2)?

A. The top row of the Exhibit ____ (MT-2) table is lettered A through F and the far left row is numbered 1 through 22. These letters and numbers are simply for reference as we walk through the table. For example, Cell A1 refers to Big Stone Unit 1. Also, I should point out that any instances in which EPA disagreed with a state's SIP determination are noted in Columns A, D, E, and F. This is evident for one unit in North Dakota and several units in Wyoming.

I will first walk through the row for Big Stone to summarize the information contained in this Exhibit ____ (MT-2). Beginning with Column A, this contains the name of the Facility and Unit that is subject to BART. Column B is the Boiler Firing Method, which for Big Stone is a cyclone boiler. Column C is the Year 2012 NOx emission rate that the unit emitted, which for Big Stone was 0.70 pounds per million BTU. Column D is the BART determination that was made by either the state or EPA in terms of a NOx pounds per million BTU emission rate, which for Big Stone was 0.10 pounds per million BTU. Column E is the specific NOx control technology that was determined to be BART, which was SCR plus SOFA for Big Stone Plant. Finally, Column F is the estimated cost effectiveness from installing the NOx controls, which for Big Stone Plant was $825 per ton.

I will now move through a second example in row 4, for Milton R. Young Unit 1. Similar to Big Stone, this unit is also a cyclone boiler. The unit's 2012 emission rate was

0.34 pounds per million BTU. BART for this unit was determined to be SNCR plus advanced SOFA to achieve 0.36 pounds per million BTU, and the cost effectiveness was calculated to be $1659 per ton. Note that footnote three clarifies that this unit has actually already installed the BART technology, which explains why their 2012 emission rate already meets the BART limits.

Finally, I will move to an example in row 8 at the top of page 2 for Colstrip Unit 1 in Montana. Montana is a unique case where the state chose not to develop a SIP and therefore EPA developed a FIP for the state. Colstrip Unit 1 is a PC boiler that had a 2012 NOx emission rate of 0.31 pounds per million BTU. EPA determined BART to be SNCR plus SOFA, the same as Milton R. Young Unit 1, but Colstrip must achieve 0.15 pounds per million BTU. The cost effectiveness for Colstrip Unit 1 to install BART was estimated to be $1564 per ton. The difference in the BART emission limits between Milton R. Young Unit 1 and Colstrip Unit 1 shows a typical difference between the level of control that can be achieved by SNCR at cyclone-fired boilers versus PC-fired boilers.

Q. WHERE DID YOU GET THE INFORMATION FOR EXHIBIT ____ (MT-2)?

A. I compiled the BART determination information from each state's most current SIP or FIP actions, and the information in Columns A and B were taken from on-line EPA databases.

Q. WHAT ARE YOUR CONCLUSIONS FROM EXHIBIT ____ (MT-2)?

A. My general conclusion is that by scanning Column F, the cost effectiveness of installing SCR at Big Stone Plant is within the range, and in many cases less than, the cost effectiveness of other area NOx BART determinations. Another conclusion that I would draw is that this Exhibit reinforces the distinct differences in NOx emissions between the five cyclone boilers and all the other PC units. For example, PC units installing SNCR, such as Colstrip Units 1 and 2, are able to achieve much lower NOx emissions than cyclone-fired boilers installing SNCR, such as at Milton R. Young. Additionally, Colstrip's NOx emission limit with SNCR of 0.15 pounds per million BTU is only marginally higher than Big Stone Plant's SCR BART limit of 0.10 pounds per million BTU or the Allen S. King Plant's 2012 NOx emission rate with SCR of 0.09 pounds per million BTU. Finally, since I just mentioned the Allen S. King Plant, I should point out that this is the only other facility in this Exhibit that is substantially similar to Big Stone Plant, because it is also a cyclone boiler that burns PRB coal.

Q. STILL REGARDING EXHIBIT ____ (MT-2), ARE YOU AWARE OF THE WYOMING BART DETERMINATIONS?

A. I am generally familiar with the determinations.

Q. IT HAS RECENTLY BEEN IN THE NEWS THAT SEVERAL AREA PLANTS IN WYOMING ARE CHALLENGING THEIR BART DETERMINATIONS. IN YOUR OPINION, WHY IS THIS?

A. Wyoming is a much different case than the South Dakota BART determination for Big Stone Plant. In Wyoming, EPA is proposing to reject several state NOx BART determinations, and instead issue a FIP that would require several units to put on SCR. Similar to Big Stone Plant, the Wyoming units burn PRB coal; however, compared to Big Stone, these Wyoming units are all PC units that can obtain much lower levels of NOx with low NOx burners or SNCR than Big Stone can achieve with SNCR. Also, I would like to note that the State of Wyoming's SIP requires five PC units to install SCR to either satisfy BART or the state's long-term strategy to reduce haze.

Q. MOVING AWAY FROM EXHIBIT ____ (MT-2) ONTO A DIFFERENT TOPIC, WHAT IS THE EXPECTED VISIBILITY IMPROVEMENT FROM INSTALLING SCR VERSUS SNCR AT BIG STONE PLANT?

A. As shown in Table 6-14 of the South Dakota Regional Haze SIP, the largest deciview difference between control option 6 for SNCR and control option 8 for SCR is approximately 0.2 deciviews. Deciviews are an atmospheric haze index that expresses changes in visibility.

Q. WILL THERE BE ANY PERCEPTIBLE VISIBILITY IMPROVEMENT BY INSTALLING SCR VERSUS SNCR AT BIG STONE PLANT?

A. According to EPA, a difference of 0.5 - 1.0 deciviews is generally considered a perceptible change. Therefore, there may not be any perceptible visibility improvement between the Big Stone Plant SNCR and SCR control options.

Q. IF THE REGIONAL HAZE RULE IS ABOUT IMPROVING VISIBILITY, WHY DOES IT MAKE SENSE TO INSTALL SCR OVER SNCR WHEN THERE MAY NOT BE ANY PERCEPTIBLE VISIBILITY IMPROVEMENT BETWEEN THE TWO TECHNOLOGIES?

A. In making their BART determinations, states are required to consider all of the statutory factors together. This includes the costs of compliance, energy and non-air quality environmental impacts of compliance, the remaining useful life of the source, and the degree of visibility improvement at the source which may be reasonably anticipated to result from the use of the technology. The South Dakota DENR examined all of these factors when making their BART determination for Big Stone Plant.

A similar question came up in the proposed Montana BART determination for Colstrip Units 1 and 2. In that case, the operator of the plant argued that installing SNCR would result in no reasonably anticipated visibility benefit because it would result in a maximum visibility improvement of 0.085 deciviews (see docket ID EPA-R08-OAR-2011-0851-0178 at www.regulations.gov). However, in the final September 18, 2012

rule EPA affirmed the BART determination, stating: "Visibility impacts below the thresholds of perceptibility cannot be ignored because regional haze is produced by a multitude of sources and activities which are located across a broad geographic area." 77 FR 57867.

EPA also responded similarly to a comment they received on the proposed North Dakota Regional Haze SIP. The commenter argued that the visibility benefits which EPA claims can be achieved with NOx control technologies are not perceptible. EPA responded in the preamble to their final April 6, 2012 action on the North Dakota SIP by stating "...the BART Guidelines establish that predicted visibility improvement below perceptibility thresholds does not provide a basis to automatically eliminate a control option: 'Even though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contribution to haze may be significant relative to other source contributions in the Class I area. Failing to consider less than perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment.' " 77 FR 20908 (and citing 70 FR 39129).

Q. DO YOU HAVE ANY OTHER OBSERVATIONS ON THE SOUTH DAKOTA DENR'S BART DETERMINATION FOR SCR TECHNOLOGY OF THE BIG STONE PLANT?

A. Yes. I recently conducted a query of generating units similar to Big Stone Plant, i.e. large cyclone-fired boilers burning PRB, and found that there will not be any units similar to Big Stone that just have an SNCR installed and that are scheduled to remain operating after 2016.

For example, the Allen S. King Plant in Minnesota, which is the closest cyclone-fired PRB boiler in proximity to Big Stone, voluntarily installed an SCR in 2007 as part of Xcel Energy's Metro Emissions Reduction Project (MERP). A table summarizing my query is included as Exhibit ____ (MT-3).

Q. COULD YOU PLEASE STEP THROUGH EXHIBIT ____ (MT-3)?

A. The top row of the Exhibit ____ (MT-3) table is lettered A through H for reference as we walk through the table. Thus, Column A contains the names of various states that have cyclone-fired electric generating units that primarily fire PRB coal. The table lists the states in alphabetical order. Column B lists the name of the plant with a cyclone boiler, Column C gives the specific boiler ID of the cyclone unit, Column D gives the year the boiler first produced electricity, and Column E is the megawatt-capacity that EPA has on file for the unit. Column F is labeled "BART Eligible" with a question mark. This column will either have a Yes or No in it for each particular unit. As I mentioned earlier,

a unit is BART eligible if it was placed into operation between 1962 and 1977. Column G is labeled "Existing NOx Controls" with a designation whether or not the cyclone boiler currently has an SCR, SNCR, or RRI installed. Finally, Column H is titled "OTP Comments" which simply has my brief remarks about a few units, mainly to note if a unit is planning to, or has recently, shut down.

I will go ahead and walk through two examples in this table. First, looking at the first unit listed, the George Neal North unit in Iowa, this boiler came on line in 1964, according to EPA's database has a capacity of 135 MW, and is BART eligible. The boiler does not currently have an SCR, SNCR, or RRI installed, however it is under a consent decree to stop burning coal by April of 2016.

Perhaps for ease of reference I can also walk through the last row in the table on page 2. That row is for the one cyclone-fired boiler in Wisconsin, Edgewater Unit 4. That unit came on line in 1969, has a capacity of 321 MW, and is BART eligible. The unit currently has RRI installed, and I have noted that it is under a consent decree to retire or repower by the end of 2018.

Q. HAVE ANY OF THE GENERATING FACILITIES' EMISSIONS REDUCTIONS EQUIPMENT INSTALLATIONS IDENTIFIED IN EXHIBIT ____ (MT-3) BEEN REVIEWED BY THE COMMISSION?

A. Yes. I am generally aware that in Xcel's 2008 rate case the Commission approved Xcel's recovery of costs incurred to add an air quality control system to its Allen S. King Plant. Similar to the Big Stone Plant AQCS, the air quality control system additions included flue gas scrubbers for control of sulfur dioxide emissions, fabric filters for control of particulate matter, and selective catalytic reduction and an over-fire air system for NOx reduction.

Q. WHAT IS YOUR MAIN CONCLUSION FROM EXHIBIT ____ (MT-3)?

A. My main conclusion is that by approximately the time the Big Stone Plant SCR is operational, there will not be any units similar to Big Stone that just have an SNCR installed. I arrive at this conclusion by looking at the 29 boilers other than Big Stone in Exhibit ____ (MT-3). Nineteen of those boilers already have SCR installed. Of the ten that do not have SCR, three have recently shut down, two plan to shut down around the time the Big Stone Plant SCR will be operational, and the remaining five have installed RRI, which as I briefly discussed before is a technology that was evaluated for Big Stone to have nearly the same cost effectiveness as SCR but achieve far fewer NOx reductions. Thus, there are no units similar to Big Stone Plant that are scheduled to be operating past 2016 with just an SNCR installed.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

TO: COMMISSIONERS, ILLONA JEFFCOAT-SACCO AND PAT FAHN

FROM: MARK GRUMAN, RATEPAYER ADVOCACY STAFF MG

SUBJECT: BIG STONE AQCS, CASE NOS. PU-11-163 AND PU-11-165

DATE: APRIL 11, 2012

CC: MARK BRING AND DAN KUNTZ

After listening to the commission's work session held on March 23, 2012, staff is concerned with the possible outcome of not granting a full ADP decision in the above referenced cases. As you know, the ratepayer advocacy staff supported the Big Stone AQCS proposal submitted by MDU and Otter Tail. While we understand the commission's principled objections, we believe the ramifications of maintaining that course will be harmful to the ratepayers in the long-run.

Under North Dakota's Administrative Agencies Practice Act Section 28-32-25, an administrative agency may avail itself of information or evidence not presented at a hearing as long as all parties are in agreement as to its inclusion into the record. A ten days' notice is required for further testimony; however, the required ten days' notice can also be shortened by agreement of the parties to the case if an immediate hearing is desired by the commission.

We request that the commission avail itself of competent and relevant information not presented at the formal hearing. Specifically, we request that the commission consider the following information not discussed at the hearing:

1. Absent a full ADP decision, the project will be delayed and possibly abandoned as it is too large of an investment to secure financing by the largest owner. According to Otter Tail's 2010 annual report to the commission, its total company rate base is $446 million. Otter Tail's ownership share of the AQCS project is 53.9% of $489 million or $263 million.

2. Since the hearing, the U S Senate failed to pass an extension of the Production Tax Credit last month. As you recall, staff's analysis determined that a Wind/Gas/Market approach to securing electricity was slightly cheaper than the proposed AQCS project but that the volatility of natural gas prices and market prices would be a concern for this alternative approach. Without the extension of the PTC, AQCS is now estimated to be nearly 1.5 cents/kWh cheaper than the next least cost resource scenario of Wind/Gas/Market.

3. As the commission will recall from the Big Stone 2 hearing, the building of Big Stone 2 would have enabled the exportation of an additional 500 MW's of electricity from North Dakota. The commission should consider by inference the impact that closing down Big Stone would have on regional transmission facilities, including North Dakota's export capabilities. I say inference because transmission studies are expensive and time consuming to complete. While it is likely Otter Tail would sell its share of Big Stone and

the plant would continue to run, it is not assured and at a minimum would be costly to its ratepayers.

4. There is very strong language supporting the recovery of federally mandated costs in NDCC 49-05-04.2 to not only allow a return on such investments and associated operating expenses but also a current return on construction work in progress. Since the formal hearing in November, the Environmental Protection Agency has taken final action to approve South Dakota's State Implementation Plan to address regional haze. The commission should consider whether this new action constitutes a federal environmental mandate in reaching its decision in these proceedings.

5. If the commission desires to create an incentive for the companies to aggressively manage its AQCS project costs, the commission should consider capping the ADP at the estimated price without coverage for the 20% overage as requested in the application. Doing so will require the companies to request cost recovery for any costs over the estimated price and will help ensure that the project remains the least cost option for ratepayers. This is not to say that imprudently incurred costs are covered so long as the cap it met. Staff believes an ADP is a regulatory compact in principle and does not extend to imprudently incurred costs. In this regard, the responsibilities of management remains throughout the construction period and until final costs and rates are approved by the commission. This approach would provide needed assurance to financing institutions yet put some risk on management to perform.

6. Pursuant to an inquiry from Terry Graumann, Manager of Environmental Services for Otter Tail Power Company, Tom Bachman of the North Dakota Department of Health indicated support for the suite of control technologies as proposed by MDU and OTP. Although Mr. Bachman has not been recently contacted, his presence could be requested if the commission so desires. The following is a copy of the email received:

> This email is in response to inquiry about North Dakota's criteria for determining Best Available Retrofit Technology (BART) under the Regional Haze Program. The North Dakota Department of Health (NDDH) used a cost effectiveness threshold of $3,650 per ton of pollutant removed and an incremental cost threshold of $6,500 per ton of pollutant removed. Selective Catalytic Reduction (SCR) was not required for North Dakota sources because it was determined to be technically infeasible and/or exceeded our cost thresholds. The high concentration of sodium and potassium in the fly ash from North Dakota lignite can cause SCR catalyst poisoning, blinding and plugging. Since SCR technology was not demonstrated to work for North Dakota lignite, it was considered technically infeasible. However, SCR is a proven technology for units burning subbituminous coal, such as the Big Stone Generating Station (Big Stone). Our review of the BART analysis for Big Stone indicates a cost effectiveness of $825 per ton of NOx removed for SCR plus separated over fire air. The incremental cost from the next most efficient control technology was $871 per ton of NOx removed. The NDDH considers these costs to be very reasonable. Not knowing all of the data surrounding the BART determination for Big Stone, and assuming the economic assessment to be valid, it would be the NDDH's view that SCR would have been economically feasible based on the cost effectiveness thresholds used for North Dakota's BART assessments.

State and EPA NOx BART Determinations for SD, ND, MT, MN and WY[1]

	A	B	C	D	E	F
	Facility and Unit	Boiler Firing Method	Year 2012 NOx Emission Rate (lb/mmbtu)	BART Determination: NOx Rate (lb/mmbtu on a 30-day rolling average)	BART Determination: NOx Controls[2]	BART Cost Effectiveness ($/ton NOx removed)
	SOUTH DAKOTA					
1	Big Stone Unit 1 (1975, 470 MW)	Cyclone	0.70	0.10	SCR + SOFA	$825
	NORTH DAKOTA					
2	Stanton Station Unit 1 (1967, 130 MW)	Pulverized Coal (PC)	0.24	0.29 (Lignite) 0.23 (Subbituminous)	SNCR + OFA + LNB	$3052 (Lignite) $3,778 (Sub)
3	Coal Creek Units 1 and 2 (Unit 1 1979, 554 MW) (Unit 2 1981, 560 MW) ***Proposed ND State SIP***	PC	0.21 (Unit 1) 0.15 (Unit 2)	***SIP***: 0.17	***SIP***: Additional SOFA + LNB	***SIP***: $411
	Coal Creek Units 1 and 2 ***Final EPA FIP***			***FIP***: 0.13	***FIP***: SNCR + SOFA + LNB	***FIP***: $2500
4	Milton R. Young Unit 1 (1970, 250 MW)	Cyclone	0.34[3]	0.36[3]	SNCR + ASOFA[3]	$1424
5	Milton R. Young Unit 2 (1977, 455 MW)	Cyclone	0.33[3]	0.35[3]	SNCR + ASOFA[3]	$1268
6	Leland Olds Station Unit 1 (1966, 221 MW)	PC	0.24	0.19	SNCR + SOFA	$2487
7	Leland Olds Station Unit 2 (1975, 448 MW)	Cyclone	0.31	0.35	SNCR + SOFA	$1659

[1] Information compiled from: State and EPA Regional Haze SIP and FIP actions for SD, ND, MT, MN, and WY; EPA's Clean Air Market Database at http://ampd.epa.gov/ampd/; and EPA table of coal unit characteristics 2012 at http://www.epa.gov/airmarkets/images/CoalUnitCharacteristics2012.xls.

[2] LNB = Low NOx Burners
OFA, SOFA, ASOFA = Over-fire Air, Separated Over-fire Air, Advanced Separated Over-fire Air
SCR, SNCR = Selective Catalytic Reduction, Selective Non-Catalytic Reduction

[3] Milton R. Young installed this technology during 2010 and 2011, which explains why the 2012 NOx emission rate in Column C already meets the BART limits in Column D.

State and EPA NOx BART Determinations for SD, ND, MT, MN and WY

	A	B	C	D	E	F
	Facility	Boiler Firing Method	Year 2012 NOx Emission Rate (lb/mmbtu)	BART Determination: NOx Rate (lb/mmbtu on a 30-day rolling average)	BART Determination: NOx Controls	BART Cost Effectiveness ($/ton NOx removed)
	MONTANA[4,5]					
8	Colstrip Unit 1 (1975, 307 MW)	PC	0.31	0.15	SNCR + SOFA	$1564
9	Colstrip Unit 2 (1976, 307 MW)	PC	0.33	0.15	SNCR + SOFA	$1571
	MINNESOTA					
10	Sherburne County Unit 1 (1976, 762 MW)	PC	0.19	0.15	SOFA + LNB + Optimized Controls	$430
11	Sherburne County Unit 2 (1977, 752 MW)	PC	0.19	0.15	Existing LNB/SOFA + Optimized Controls	$360
12	Boswell Energy Center Unit 3 (1973, 351 MW)	PC	0.05[6]	0.07	SCR + LNB + OFA[6]	$3201
13	Allen S King[5] (1968, 610 MW)	Cyclone	0.09	Not Applicable[7]	Not Applicable[7]	Not Applicable[7]

[4] The State of Montana chose to not propose a SIP, therefore EPA developed a FIP for the state

[5] The JE Corette Plant (1968, 158 MW) was also subject to BART, however the plant is planned to be shuttered in April 2015

[6] Boswell 3 installed the SCR, LNB, and OFA equipment in 2009

[7] Allen S King Unit 1 was determined to not be subject to BART because it already had installed SCR in 2007 as part of Xcel Energy's voluntary Metro Emissions Reduction Project (MERP)

State and EPA NOx BART Determinations for SD, ND, MT, MN and WY

	A	B	C	E	F	G
	Facility	Boiler Firing Method	Year 2012 NOx Emission Rate (lb/mmbtu)	BART Determination: NOx Rate (lb/mmbtu on a 30-day rolling average)	BART Determination: NOx Controls	BART Cost Effectiveness ($/ton NOx removed)
	WYOMING *Information below based on proposed EPA action on June 10, 2013*					
14	Jim Bridger Unit 1 (1974, 530 MW)	PC	0.18	Phase 1 BART: 0.28 Phase 2 Long Term Strategy: 0.07	Phase 1: SOFA + LNB Phase 2: SCR by 12/31/2022	Phase 1: $256 Phase 2: $2393
15	Jim Bridger Unit 2 (1975, 530 MW)	PC	0.19	Phase 1 BART: 0.28 Phase 2Long Term Strategy: 0.07	Phase 1: SOFA + LNB Phase 2: SCR by 12/31/2021	Phase 1: $308 Phase 2: $3015
16	Jim Bridger Unit 3 (1976, 530 MW)	PC	0.20	0.07[8]	SCR + SOFA + LNB[8] by 12/31/2015	$2961
17	Jim Bridger Unit 4 (1979, 530 MW)	PC	0.19	0.07[8]	SCR + SOFA + LNB[8] by 12/31/2016	$2492
18	Laramie River Units 1 - 3 (Unit 1 1980, 565 MW) (Unit 2 1981, 570 MW) (Unit 3 1982, 570 MW) ***Proposed WY State SIP***	PC	0.17 (Unit 1) 0.19 (Unit 2) 0.19 (Unit 3)	***SIP***: 0.21	***SIP***: OFA + LNB	***SIP***: ≈$2000
	Laramie River Units 1 - 3 ***Proposed EPA FIP***			***FIP***: 0.07	***FIP***: SCR + OFA + LNB	***FIP***: ≈$3700
19	Dave Johnston Unit 3 (1964, 220 MW) ***Proposed WY State SIP***	PC	0.21	***SIP***: 0.28	***SIP***: OFA + LNB	***SIP***: $648
	Dave Johnston Unit 3 ***Proposed EPA FIP***			***FIP***: 0.07	***FIP***: SCR + OFA + LNB	***FIP***: $2540

[8] For Jim Bridger Units 3 and 4, the State technically determined that BART was SOFA + LNB and that SCR is being required as part of the State's long term haze strategy. However, the timeframe to install SCR is within the timeframe that BART controls would have to be installed pursuant to 51.308(e)(iv).

State and EPA NOx BART Determinations for SD, ND, MT, MN and WY

	A	B	C	E	F	G
	Facility	Boiler Firing Method	Year 2012 NOx Emission Rate (lb/mmbtu)	BART Determination: NOx Rate (lb/mmbtu on a 30-day rolling average)	BART Determination: NOx Controls	BART Cost Effectiveness ($/ton NOx removed)
	WYOMING *Continued* *Information below based on proposed EPA action on June 10, 2013*					
20	Dave Johnston Unit 4 (1972, 330 MW) ***Proposed WY State SIP***	PC	0.15	***SIP***: 0.15	***SIP***: OFA + LNB	***SIP***: $137
	Dave Johnston Unit 4 ***Proposed EPA FIP***			***FIP***: 0.12	***FIP***: SNCR + OFA + LNB	***FIP***: $740
21	Naughton Units 1 - 2 (Unit 1 1963, 160 MW) (Unit 2 1968, 210 MW) ***Proposed WY State SIP***	PC	0.34 (Unit 1) 0.22 (Unit 2)	***SIP***: 0.26	***SIP***: OFA + LNB	***SIP***: ≈$400
	Naughton Unit 1 - 2 ***Proposed EPA FIP***			***FIP***: 0.07	***FIP***: SCR + OFA + LNB	***FIP***: ≈$2300
22	Naughton Unit 3 (1971, 330 MW)	PC	0.35	0.07	SCR + OFA + LNB	$3243
23	Wyodak Unit 1 (1978, 335 MW) ***Proposed WY State SIP***	PC	0.19	***SIP***: 0.23	***SIP***: OFA + LNB	***SIP***: $881
	Wyodak Unit 1 ***Proposed EPA FIP***			***FIP***: 0.17	***FIP***: SNCR + OFA + LNB	***FIP***: $1979

EPA Database of Large Cyclone-Fired Boilers Primarily Firing PRB Coal[1]

A	B	C	D	E	F	G			H
State	Plant Name	Boiler /Generator ID	Boiler Year On Line	MW Capacity	BART Eligible?	Existing NOx Controls			OTP Comments
						SCR	SNCR	RRI	
Iowa	George Neal North	1	1964	135	Yes				Under Consent Decree to stop burning coal by April 2016
Illinois	Baldwin Energy Complex	1	1970	624	Yes	X			
	Baldwin Energy Complex	2	1973	629	Yes	X			
	Coffeen	1	1965	340	Yes	X			
	Coffeen	2	1972	560	Yes	X			
	Joliet 9	6	1959	314	No			X	
	Kincaid Generation LLC	1	1967	584	Yes	X			
	Kincaid Generation LLC	2	1968	584	Yes	X			
	Powerton	5	1973	770	Yes			X	
	Powerton	6	1976	770	Yes			X	
	Will County	1	1955	151	No				Shut down in Dec. 2010
	Will County	2	1955	148	No				Shut down in Dec. 2010
Indiana	Michigan City	12	1974	469	Yes	X			
	R M Schahfer	14	1976	431	Yes	X			
	State Line Energy	4	1962	303	Yes				Shut down in March 2012

A	B	C	D	E	F	G			H
State	Plant Name	Boiler /Generator ID	Boiler Year On Line	MW Capacity	BART Eligible?	Existing NOx Controls			OTP Comments
						SCR	SNCR	RRI	
Kansas	La Cygne	1	1973	724	Yes	X			
Minnesota	Allen S. King	1	1968	610	Yes	X			
Missouri	Asbury	1	1970	213	Yes	X			
	New Madrid	1	1972	580	Yes	X			
	New Madrid	2	1977	580	Yes	X			
	Sibley	3	1969	401	Yes	X			
	Sioux	1	1967	497	Yes			X	
	Sioux	2	1968	497	Yes			X	
	Thomas Hill	1	1966	175	Yes	X			
	Thomas Hill	2	1969	275	Yes	X			
South Dakota	Big Stone	1	1975	470	Yes				SCR required by Regional Haze SIP
Tennessee	Allen Steam Plant	1	1958	245	No	X			Per Consent Decree, must also install FGD on all units or retire by 12/31/18
	Allen Steam Plant	2	1959	245	No	X			
	Allen Steam Plant	3	1959	245	No	X			
Wisconsin	Edgewater	4	1969	321	Yes			X	Per Consent Decree, must retire or repower by 12/31/18

[1] Information compiled from: Emissions & Generation Resource Integrated Database (eGRID2012 Version 1.0) at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html, EPA's Clean Air Markets Division Database at http://ampd.epa.gov/ampd/, and EPA table of coal unit characteristics 2012 at http://www.epa.gov/airmarkets/images/CoalUnitCharacteristics2012.xls. Comments column added from OTP research. In this Exhibit, large boilers are defined to be boilers that are greater than 125 MW.

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

Before the Public Service Commission of North Dakota

Case Nos. PU-13-83 and PU-13-85

Direct Testimony
of
Andrea L. Stomberg

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

A. Yes. My name is Andrea L. Stomberg, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am the Vice President of Electric Supply for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

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

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

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

A. I graduated from the University of Washington with a bachelor's degree in Geology, from Oregon State University with a Master of Science degree in Soils, and from the University of Mary, Bismarck, with a master's degree in business management. I worked for the North American Coal

Corporation for ten years in surface mine permitting, reclamation planning and oversight. I worked for Montana-Dakota for about 15 years in the environmental field prior to my current position.

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

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

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

A. The purpose of my testimony is to explain why the costs and expenses that have been and will be incurred by Montana-Dakota for the Air Quality Control System ("AQCS") at the Big Stone Plant are prudent. Mr. Rolfes is providing testimony explaining how the Owners have managed the AQCS project, as well as the current status of the project, to demonstrate that the costs and expenses incurred by the BSP owners are reasonable.

Q. Do your responsibilities as Vice President- Electric Supply include responsibilities related to the Big Stone Plant?

A. Yes. Montana-Dakota owns 22.7 percent of the Big Stone Plant. In my position as Vice President-Electric Supply, I serve on the Big Stone Plant Engineering and Operating (E&O) Committee along with Alan Welte, Generation Director for Montana-Dakota. I have served on this committee since 2003. The E&O committee jointly makes significant decisions regarding plant operations.

Q. Can you explain your understanding of the EPA's Regional Haze Rule and how it affects the Big Stone Plant?

A. The Clean Air Act, 42 U.S.C. §7479, mandates a national goal of remedying and preventing visibility impairment from man-made air pollution in specified Class I areas of the United States which include national parks and wilderness areas. In 1999, EPA promulgated the Regional Haze Rule (40 CFR Part 51), which was revised in 2005, to implement this requirement of the Clean Air Act. The Regional Haze Rule includes the requirement to install the Best Available Retrofit Technology (BART) on major generating sources, including existing electric generating units that were placed into operation between 1962 and 1977. Because the Big Stone Plant began commercial operation on May 1, 1975, it was subject to the requirements of the Regional Haze Rule for the installation of BART.

Q. How was it determined if the Big Stone Plant would be required to install BART?

A. Under the Regional Haze Rule, state environmental agencies are authorized to submit a State Implementation Plan (SIP) to EPA for review and approval, outlining how the state intends to bring affected sources subject to jurisdiction into compliance with the rule. If a state does not propose a SIP, EPA will develop a plan to control emissions from sources within that state that are shown to contribute to visibility impairment. South Dakota, like North Dakota, elected to pursue adoption of a SIP

through its state agency, in this case the South Dakota Department of Environmental and Natural Resources (DENR).

In response to the Regional Haze Rule, Otter Tail, as the operator of the Big Stone Plant, performed an evaluation of the visibility impact of the plant's operations on seven Class 1 areas in four states. Based on this evaluation, the South Dakota DENR determined the Big Stone Plant's emissions contribute to impairment of visibility in multiple Class 1 areas and therefore the plant was subject to the BART requirements of the Regional Haze Rule.

Q. How was BART determined for the Big Stone Plant?

A. Otter Tail, as agent for the owners, proposed that separated over-fired air (SOFA) technology be deployed as BART for the Big Stone Plant in its BART Technology analysis (Appendix C to the SD SIP). On September 15, 2010, the South Dakota DENR, Board of Minerals and Environment, adopted Administrative Rules of South Dakota chapter 74:36:21 which imposed limits on nitrogen oxides, sulfur dioxides, and particulate matter that were substantially lower than those in the existing Big Stone Plant permit. The South Dakota Regional Haze SIP included the following as BART technologies applicable to the Big Stone Plant:

- Selective catalytic reduction technology (SCR) with separated over-fired air for control of NOx.
- Semi-dry flue gas desulfurization for control of SO2.
- A baghouse for control of particulate matter.

On January 21, 2011, the South Dakota DENR submitted its SIP to the EPA for review and approval. On March 29, 2012, the EPA approved the South Dakota SIP and the final rule was published on April 26, 2012. Under the South Dakota Regional Haze Rule, the Big Stone Plant must achieve BART compliance expeditiously but no later than five years after EPA's approval of the South Dakota SIP, or April 26, 2017.

Q. Would the Big Stone Plant be forced to close without these environmental upgrades?

A. Yes. The plant could not operate using coal as its fuel source after April 26, 2017 without the environmental upgrades adopted in the South Dakota SIP.

Q. What did the Owners consider when deciding whether to pursue installation of the BART at the Big Stone Plant?

A. The Owners obtained a cost estimate from the engineering firm of Sargent & Lundy for the installation of the BART technology identified in the South Dakota SIP at the Big Stone Plant. The estimate of a BART compliant AQCS was $489,397,400 in 2015 dollars, with an accuracy of plus or minus 20 percent. The Owners then compared the construction and operation costs of Big Stone with the AQCS to several other generation alternatives. These alternatives and the assessment results were discussed in Montana-Dakota's application for Advance Determination of Prudence for the AQCS (Docket No. PU-11-163). In

each instance, the assessment concluded that Big Stone with the AQCS was the least cost option.

Q. Did Montana-Dakota conduct any analysis of the Big Stone AQCS and other generation alternatives specific to its generation needs?

A. Yes. Montana-Dakota separately analyzed the cost effectiveness of the Big Stone AQCS project as part of its 2011 Integrated Resource Plan ("IRP"). Montana-Dakota modeled sensitivity scenarios surrounding the AQCS and various alternatives. Even when the modeled cost of the AQCS was nearly doubled from its original estimate, it was still selected as part of Montana-Dakota's resource plan recommended in its 2011 IRP.

Q. What was Montana-Dakota's next step in response to the results of these analyses?

A. Because of the substantial cost of the AQCS and the impact of those costs on customers, Montana-Dakota applied for an Advance Determination of Prudence from this Commission on May 20, 2011. In its Findings of Fact, Conclusions of Law and Order dated May 9, 2012 in Case No. PU-11-163, the Commission found "the continued operation of Big Stone is prudent and a least cost alternative to securing alternative generation" and concluded "the continued operation of the Big Stone Plant is prudent."

Q. In its order in Case No. PU-11-163, the Commission stated no determination was made "regarding the prudence of using either

SCR or SNCR technology in the AQCS". What NOx control technology is included in the AQCS?

A. As stated previously and as noted on page 102 of the South Dakota's Regional Haze State Implementation plan developed by the DENR, along with ARSD Chapter 74:36:21, the South Dakota SIP required the installation of SCR technology as BART for the Big Stone Plant. Accordingly, SCR is the NOx control technology included in the AQCS suite of air quality controls.

Q. Could the Big Stone Plant Owners have instead installed SNCR or SOFA as the NOx control technology?

A. Not if the Owners wanted to continue operation of the Big Stone Plant after April 2017. The South Dakota DENR prescribed SCR as the BART for NOx control at Big Stone.

Q. What NOx control technology did North Dakota adopt in its Regional Haze Rule SIP for lignite coal-fired electric generation located in this state?

A. North Dakota adopted SNCR control technology as BART for NOx control of cyclone fired boilers.

Q. Considering that North Dakota adopted SNCR control technology for NOx in its SIP approved by the EPA, why didn't the Big Stone Owners use SNCR as BART for the Big Stone Plant?

A. The North Dakota SIP identifies NOx control technology for lignite fired generation. Big Stone is fueled by subbituminous coal. The

feasibility and effectiveness of NOx control technologies differs for lignite and subbituminous coal generation because of the chemistry of the coal. Significant problems using SCR for NOx control on lignite fired plants have been demonstrated, particularly for cyclone boilers, and so SCR has not been found to be an effective NOx control technology for lignite fueled generation. These issues do not exist for generation fueled by subbituminous coal. More importantly, however, the Big Stone Plant is located in South Dakota and therefore the Plant must operate in compliance with federal and state regulations applicable to plants located in South Dakota. The Owners do not have the luxury to decide which rules to comply with even if they disagree with the rationale or wisdom of a particular rule. South Dakota had the authority, subject to EPA review and approval, to determine BART for control of NOx for coal fueled plants located in South Dakota, including Big Stone. If the Big Stone Owners want to continue operation of the Big Stone Plant, which they, as well as this Commission, have determined is prudent, installation of SCR technology is mandatory and neither SOFA alone, nor SNCR technology is an option. I want to stress the AQCS is not a situation in which the Owners have adopted an environmental control option that is more stringent or more expensive than that required for continued operation of the plant; they have adopted the specific control technology that is legally mandated for continued operation of the plant.

Q. In light of the South Dakota SIP, would use of anything other than SCR for the control of NOx as part of the AQCS have been prudent?

A. No. Although use of SOFA alone or SNCR rather than SCR technology would have reduced the cost of the AQCS, it would not have allowed continued operation of the Plant which in this case is the threshold of prudence review of the selected technologies and incurred costs. Installation of SOFA or SNCR at Big Stone as part of the AQCS project, in lieu of the required SCR technology, would have been a useless expenditure when made and therefore clearly imprudent.

Q. Is it fair and reasonable that North Dakota customers of Montana-Dakota should be required to pay for the cost of environmental controls adopted by another state?

A. Yes. Customers are receiving the benefit of electricity from this cost effective base load generation facility, so it is fair and reasonable that the price they pay for that electricity includes the costs of operating the generation plant including the costs of compliance with the laws applicable to operation of the facility. As determined by the Commission in Case No. PU-11-163, continued operation of the Big Stone Plant, even considering the requirements of the South Dakota SIP, was a least cost and prudent decision.

Q. Are you aware of other types of situations in which the policies and laws of one state affect the operation and cost of facilities in that

state that are then included within prices paid by customers in other states?

A. Any product that is produced in one state and sold to customers in another state likely has cost components reflective of where it was produced; some of which may be more expensive and some of which may be less expensive than a similar product produced elsewhere. For example, property taxes on generation facilities are included in the price of electricity sold not only outside the boundaries of the local taxing authority within the state but in the price of electricity sold outside the state. North Dakota's production taxes on generation or severance taxes on coal and natural gas production are reflected in the price of electricity sold throughout the Midwest, including South Dakota, when produced by generating facilities located in the State. Specifically, with regard to environmental regulations, North Dakota has adopted coal reclamation regulations and coal ash disposal regulations that in some instances are more stringent than what might be required by federal law or the laws of other states. The cost of compliance with those regulations is part of the cost of generating electricity in North Dakota and it is fair and reasonable that customers in other states that benefit from that electric generation bear the cost of full compliance rather than just customers in North Dakota.

Q. Does this complete your testimony?

A. Yes, it does.

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

Before the Public Service Commission of North Dakota

Case Nos. PU-13-83 and PU-13-85

Direct Testimony
of
Tamie A. Aberle

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

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

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

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

Q. What are your responsibilities as the Director of Regulatory Affairs?

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

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

A. I graduated from Moorhead State University, Moorhead, Minnesota in 1982 with a Bachelor of Science degree in Accounting. I began my

career with Montana-Dakota in 1983 in the Regulatory Affairs Department, holding several positions within the Department including Rate Administration Supervisor, Pricing and Tariff Manager and Regulatory Affairs Manager before attaining my current position in 2012.

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

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

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

A. The purpose of my testimony is to explain the Company's proposed Environmental Cost Recovery Rider Rate 57 tariff and how the proposed Rate 57 tariff addresses each of the issues for consideration stated on pages 2 and 3 of the Commission's Notice of Consolidated Hearing, dated July 10, 2013 in Case Nos. PU-13-83 and PU-13-85, Montana-Dakota's Application for Approval of an Environmental Cost Recovery Rider.

Q. Before you explain the Company's proposed Environmental Cost Recovery Rider Rate 57 tariff, would you first inform the Commission why Montana-Dakota chose to file an environmental rider tariff?

A. Yes. Montana-Dakota is proposing to implement an Environmental Cost Recovery Rider (ECRR) tariff that allows the Company to recover a current return on Montana-Dakota's share of the Construction Work in Progress (CWIP) costs associated with the required environmental retrofit equipment to be installed at Big Stone. The ECRR is proposed in

accordance with the North Dakota Century Code as provided in Section 49-05-04.2(1):

> The commission may approve, reject, or modify a tariff filed under section 49-05-06, which provides for an adjustment of rates to recover jurisdictional capital costs and associated operating expenses incurred by a public utility to comply with federal environmental mandates on existing electricity generating stations. For purposes of this section, federal environmental mandates are limited to any requirements under the Clean Air Act, the Clean Water Act, or any other federal law or rule designed to protect the environment. Associated operating expenses are costs incurred by the public utility to comply with the environmental mandate. The tariff must:
>
> a. Allow the public utility to recover on a timely basis its investment in capital costs and associated operating expenses incurred to meet federal environmental mandates not reflected in the utility's general rate schedule.
> b. Allow a return on the public utility's investment made to meet federal environmental mandates at the level approved in the utility's most recent general rate case.
> c. Provide a current return on construction work in progress to meet federal environmental mandates provided the cost recovery from retail customers of the allowance for funds used during construction is not sought through any other means.
> d. Terminate cost recovery after the public utility's costs and expenses to meet federal environmental mandates have been recovered fully or have been reflected in the utility's general rate tariffs.

The establishment of this tracker is beneficial to both the Company and its customers. First it provides Montana-Dakota with a rate mechanism by which it can recover costs incurred as a result of compliance with environmental mandates on generating stations outside of a general rate case, thereby reducing cash flow requirements during the construction phase. Second, the tariff allows for the gradual increase in customer bills over time as compared to a larger rate increase that would occur if the total cost of the project, plus the AFUDC accrued during the project, were

introduced into rates upon completion of the project, which often times, is a number of years as is the case with the Big Stone AQCS project. Customers also benefit through the implementation of the tariff because carrying costs will not be compounded during construction, reducing the amount of rate base to be recovered through rates over the life of the project.

Q. Please explain the Environmental Cost Recovery Rider Rate 57 tariff submitted on February 11, 2013 and updated on May 31, 2013.

The ECRR tariff specifies the procedure to be used in recovering the jurisdictional costs incurred by Montana-Dakota in complying with federal and state environmental mandates. Costs to be recovered include actual capital expenditures, depreciation, taxes and a current return on the project costs during construction. The projected Construction Work in Progress (CWIP) costs included in the calculation of Montana-Dakota's proposed ECRR reflect an allocation of CWIP to North Dakota based on the peak demand allocator applicable each year. The Application submitted on February 11, 2013 was based on Montana-Dakota's share of estimated project costs of $52,941,152 through March 31, 2014. That amount was updated in May to reflect estimated costs of $46,639,830 through March 31, 2014 as shown on Exhibit 1, pages 2 and 3 included with the May 31, 2013 update. The update in costs reflects the reduction in the total budget from $489 million to $405 million as described more fully by Mr. Mark Rolfes. Montana-Dakota's ownership share in the Big Stone Plant is 22.7%, and therefore Montana-Dakota is responsible for 22.7% of the costs or $92

million. Montana-Dakota's North Dakota jurisdictional share of this cost responsibility is approximately 71.3% or $65.5 million.

The revenue requirement for the AQCS at Big Stone as shown on Exhibit 1 page 1 of the May 31 update reflects actual Construction Work in Progress costs incurred through April 30, 2013 plus projected costs for the period May 1, 2013 through March 31, 2014. The total amount requested to be recovered through this first ECRR adjustment is $2,751,330. This amount represents the revenue requirement associated with the average CWIP balance for the period January 2013 through March 2014 based on the Company's rate of return authorized in the last electric rate case (Case No. PU-10-124). The revenue requirement was allocated to the rate classes using the demand factor identified in the Company's most recent general electric rate case. A separate ECRR amount is being proposed for each of the classes shown below, similar to Montana-Dakota's currently effective Transmission Cost Adjustment, and will be shown as a separate line item on customer bills denoted as "Req Environmental Cost".

The ECRR rates proposed are as follows.

Residential and Small General	$0.00203 per Kwh
Large General	$0.00164 per Kwh
Lighting	$0.00120 per Kwh

The ECRR includes an annual true-up from the previous year based on actual expenditures. The true-up will be reflected in the next ECRR adjustment filing. Also, future filings will reflect a thirteen month average balance for the determination of CWIP.

Q. Would you please identify the issues the Commission noticed for consideration regarding the Company's proposed environmental cost recovery tariff on its Notice dated July 10, 2013?

A. Yes. Four issues were identified on pages 2 and 3 of the Commission's Notice of Hearing in regard to the Company's proposed environmental cost recovery tariff. (1) Does each tariff allow the respective public utility to recover on a timely basis its investment in capital costs and associated operating expenses incurred to meet federal environmental mandates not reflected in the utility's general rate schedule? (2) Does each tariff allow a return on the respective public utility's investment made to meet federal environmental mandates at the level approved in the utility's most recent general rate case? (3) Does each tariff provide a current return on construction work in progress to meet federal environmental mandates provided the cost recovery from retail customers of the allowance for funds used during construction is not sought through any other means? (4) Does each tariff terminate cost recovery after the respective public utility's costs and expense to meet federal environmental mandates have been recovered fully or have been reflected in the utility's general rate tariffs?

Two additional questions were included for consideration on page 3 of the Commission's Notice for Hearing in regard to the proposed environmental cost recovery rate adjustment. (1) Does each rate adjustment comply with the respective tariff? (2) Are each utility's incurred

costs and expenses to meet federal environmental mandates reasonable and prudent?

Q. Would you please address the issues for consideration relating to the Company's proposed Environmental Cost Recovery Rider Rate 57 tariff?

A. Yes. I will address each issue noticed by the Commission in regard to Montana-Dakota's proposed tariff. First, the proposed ECRR (Rate 57) would allow Montana-Dakota to recover on a timely basis its investment in capital costs and associated operating expenses incurred to meet federal environmental mandates not reflected in Montana-Dakota's existing rates. The ECRR Rate 57 tariff provides Montana-Dakota with a rate mechanism that closer aligns the recovery of such environmental mandated costs as the costs are being incurred rather than to defer cost recovery, accrue Allowance for Funds Used During Construction (AFUDC) and seek recovery at the completion of this multi-year project.

The proposed tariff also provides a return on Montana-Dakota's investment made to meet federal environmental mandates at the level approved in the utility's most recent general rate case. As stated in Paragraph 2, section a. of Rate 57, the return component of the revenue requirement calculation will be the authorized rate of return from the Company's most recent general rate case. In compliance with the proposed tariff and the Statute, the return on rate base was calculated using the authorized capital structure approved in Case No. PU-10-124,

the Company's most recent general rate case. The return on rate base, calculated using the authorized capital structure, is shown in Exhibit 1, page 2 of 3 of the Company's May 31, 2013 Revisions to the Application for Approval of an Environmental Cost Recovery Rider.

The proposed tariff provides a current return on construction work in progress to meet federal environmental mandates and Montana-Dakota is not seeking cost recovery from retail customers of the allowance for funds used during construction (AFUDC) through any other means. Upon approval of the ECRR, AFUDC will no longer be accrued.

Finally, while the Rate 57 tariff will remain active, the ECRR rate applicable to the AQCS project will end upon completion of the project. Montana-Dakota is proposing to file an updated Environmental Cost Recovery Rider (ECRR) annually, to be effective April 1 of each year, with the Company ceasing collection of the rider at which time the equipment is operational and included in rate base pursuant to a general rate case.

Q. In regard to the proposed rate adjustment itself, does Montana-Dakota's rate adjustment comply with its proposed Rate 57 tariff?

A. The rate adjustment does comply with the Company's proposed Rate 57 tariff. As shown in Exhibit 1, pages 2 and 3 of the Company's May 31, 2013 Revisions to the Application for Approval of an Environmental Cost Recovery Rider, the revenue requirement reflects only those costs applicable to the AQCS at Big Stone.

In compliance with Paragraph 2, Section b of Rate 57, the revenue

requirement is allocated to the rate classes using the Company's AED Factor No. 2 established in the Company's most recent general rate case as shown on page 1 of Exhibit 1 to the May 31, 2013 Revisions to Application. The allocated class costs are then further divided by the forecasted Kwh sales to determine each class' ECRR.

Q. Does this conclude your direct testimony?

A. Yes, it does.