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

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

June 21, 2007

Illona Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
State Capitol
Bismarck, ND 58505

Re: In the Matter of the Advance Determination of Prudence Application of Otter Tail Corporation Case No. PU-06-481

In the Matter of the Advance Determination of Prudence Application of Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Case No. PU-06-482

Dear Ms. Jeffcoat-Sacco:

On behalf of both Montana-Dakota Utilities Co. (Montana-Dakota) and Otter Tail Power Corporation (Otter Tail), enclosed for filing in the above matters please find the original and seven copies of the following documents:

Case No. PU-06-481 Otter Tail:

1. Rebuttal Testimony of Ward Uggerud
2. Rebuttal Testimony of Mark Rolfes (both cases);
3. Rebuttal Testimony of Tim Rogelstad (both cases);
4. Rebuttal Testimony of Kermit Trout (both cases);
5. Rebuttal Testimony of Jeff Greig (both cases) and
6. Rebuttal Testimony of Bryan Morlock.

Case No. PU-06-482 Montana-Dakota:

1. Rebuttal Testimony of Bruce Imsdahl;
2. Rebuttal Testimony of Mark Rolfes (both cases);
3. Rebuttal Testimony of Tim Rogelstad (both cases);
4. Rebuttal Testimony of Kermit Trout (both cases);
5. Rebuttal Testimony of Jeff Greig (both cases) and
6. Rebuttal Testimony of James Heidell.

In our June 13, 2007 Notice of Intent to File Rebuttal Testimony, we did not list Mr. Rogelstad, and we had listed Ms. Andrea Stomberg instead of Mr. Imsdahl. At the time of filing we had not identified Mr. Rogelstad as a potential rebuttal witness and have since decided that

Mr. Imsdahl will be addressing identified rebuttal issues and Ms. Stomberg will not be submitting rebuttal testimony. We do not believe these inadvertent omissions cause prejudice to any party.

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

Please let me know if you have any questions. Thank you.

Sincerely,

Daniel S. Kuntz / Sara Graf

Daniel S. Kuntz
Associate General Counsel

c: The attached Service List (w/encl.)
Honorable Al Wahl

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Otter Tail Corporation, Advance Determination of Prudence Application

SERVICE LIST

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., Advance Determination of Prudence Application

Case Nos. PU-06-481, PU 06-482

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STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Otter Tail Corporation, Advance Determination of Prudence Application

AFFIDAVIT OF SERVICE

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., Advance Determination of Prudence Application

Case Nos. PU-06-481, PU 06-482

Angie Berger, of Bismarck North Dakota, being sworn, says that on June 21, 2007, a copy of the Rebuttal Testimony filed, in the above referenced cases, has been served upon the North Dakota Public Service Commission and the attached service list via FedEx and email.

Angie Berger
Angie Berger

Subscribed and sworn to before me
this 21st day of June, 2007.

Norma E. Eslinger
Notary Public

NORMA E ESLINGER
Notary Public
State of North Dakota
My Commission Expires August 30, 2011

CASE NO. PU-06-481

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER CORPORATION D/B/A

OTTER TAIL POWER COMPANY

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

REBUTTAL TESTIMONY

OF

WARD UGGERUD

SENIOR VICE PRESIDENT

OTTER TAIL POWER COMPANY

JUNE 21, 2007

REBUTTAL TESTIMONY OF WARD UGGERUD

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY OF WARD UGGERUD

I. INTRODUCTION

Q: What is the purpose of your rebuttal testimony?

A: The purpose of my rebuttal testimony is to respond to the Direct Testimony of Mr. Terry Deason. I can present the position of Otter Tail Power Company ("Otter Tail") in response to the five conditions attached to Mr. Deason's recommendation that the North Dakota Public Service Commission grant an advance prudence decision for Big Stone Unit II. Mr. Deason's outlines his five conditions at pages 47-49 of his testimony.

II. PERIODIC INFORMATIONAL FILINGS

Q: Mr. Deason recommends that Otter Tail Power Company make periodic filings with the North Dakota Public Service Commission ("Commission") on the progress by the Company to obtain necessary approvals and permits for Big Stone Unit II and an indication when construction commences. Will Otter Tail commit to do that?

A: Yes, certainly. We have already advised the Commission of the permits and approval we have already received, and we will advise the Commission of any other decisions by state or federal regulatory bodies immediately after those decisions are made. In addition, we would suggest that we report quarterly to the Commission of the status of any pending approvals.

III. ANNUAL BUDGET INFORMATION

Q: Mr. Deason's second recommendation is that Otter Tail provide the Commission with a forecasted budget each year for all construction related costs and an analysis of

deviations between the actual budget and forecasted. Will Otter Tail commit to submitting those reports?

A: Yes. I would suggest that the first report be filed within three months of a favorable Commission decision on advance prudency and then each year thereafter on the anniversary date until Big Stone Unit II goes into operation. We will certainly include in each report an analysis of any deviations between what was forecasted and what was spent. Of course, if at any time Otter Tail, or any of the other co-owners, should decide not to go forward with construction of Big Stone Unit II, we will immediately notify the Commission, along with other state and federal agencies.

IV. COAL DELIVERY MANAGEMENT SYSTEM

Q: The third recommendation by Mr. Deason is that Otter Tail implement certain practices and measures to ensure a reliable supply of coal? Will Otter Tail commit to implement those measures and practices?

A: Mr. Deason describes four operational practices and measures that he would like to see implemented to enhance delivery of coal to the Big Stone site. Not only will Otter Tail along with the other co-owners commit to implementing those measures, but Mr. Brautovich on behalf of the Burlington Northern Santa Fe Railway has also committed to working with the Big Stone II co-owners to ensure that these measures are implemented. Of course, we will maintain reports regarding these measures and we will provide these to the Commission upon request.

V. COAL DELIVERABILITY

Q: Mr. Deason's fourth recommendation also involves coal deliverability. Specifically, he recommends that Otter Tail conduct a study to determine the appropriate number of rail cars necessary to serve Big Stone and whether any additional rail cars should be light weight aluminum rail cars. Will Otter Tail commit to conduct that study?

A: Yes, we will, and the co-owners will work with the Burlington Northern Santa Fe Railway in conducting that study. We suggest that we provide that study to the Commission no later than January 1, 2011. We are also willing to meet periodically at the Commission's request to provide an update of our progress on that study.

VI. COAL INVENTORY

Q: The final recommendation from Mr. Deason is that Otter Tail conduct a study to determine the costs of maintaining a higher inventory level of coal. Will Otter Tail conduct that study?

A: We'll do that too. Again, the co-owners will work with the Burlington Northern Santa Fe Railway to conduct that study. We suggest that we file that report along with the report under the fourth recommendation regarding the appropriate number and type of rail cars, no later than January 1, 2011.

VII. AIR POLLUTION CONTROL

Q: Why is spending millions of dollars on air pollution control equipment a prudent business decision?

A: I described the air pollution equipment to be installed to control emissions from both Unit I and Unit II in my Direct Testimony at pages 14-15. Otter Tail and the other co-owners believe that installing this control equipment at the initial stages of construction of Big Stone Unit II is a sound business decision for several reasons. First, it is cheaper to install the equipment during construction than to retrofit it after operation of the plant. Also, it certainly saves us money to be able to install a single wet scrubber to control emissions from both units, rather than install two separate scrubbers. Another factor, of course, is that nobody can build a power plant without significant expenditures on air pollution control. The commitments the co-owners have made to control mercury, for instance, are a prudent choice because the federal government, through the Environmental Protection Agency, recently promulgated the Clean Air Mercury Rule, which will over the next decade require significant reductions in mercury emissions. Based on research findings, we expect that a wet scrubber will help reduce mercury emissions as well. By addressing these issues now rather than later, we believe we are saving money for our customers in the long run.

VIII. ASSET-BACKED SALES

Q: At page 47, Mr. Deason seeks clarification on how Otter Tail intends to treat any asset-backed wholesale sales that may be made from Big Stone Unit II. Can you comment?

A: First, let me emphasize that Otter Tail is proposing to construct and own Big Stone Unit II primarily for the purpose of providing electric service to our retail customers. But of course to the extent there are opportunities to maximize efficiencies of the plant by making wholesale asset-backed sales we will do that. Asset-backed wholesale revenues have

traditionally been 100% credited to retail customers through a credit to revenue requirements. Recently there has been a movement toward crediting these asset-backed wholesale margins directly to retail customers through the fuel adjustment clause. We expect that asset-backed wholesale margins may move from a revenue requirements credit to a fuel clause credit within the context of a general rate case before Big Stone Unit II is operational.

IX. FUTURE GENERATION

Q: Mr. Deason suggests at page 47 of his testimony that Otter Tail Power Company discuss whether the Coyote Station remains a potential site for generation expansion and the potential impacts that the Big Stone Unit II facility would have on the prospects of future generation in North Dakota? Can you provide some clarification?

A: Yes, I am happy to address these issues. I think first I should emphasize that our best resource planning efforts, and the efforts and forecasting by the other co-owners, including Montana-Dakota Utilities, and the Load & Capability studies performed by the Mid-Continent Area Power Pool ("MAPP") confirm that Big Stone Unit II will not address all the anticipated needs of the co-owners and certainly not the upcoming energy needs throughout the upper Midwest. Otter Tail is going to need additional generation resources within the foreseeable future, as are the other co-owners. Some of this additional generation will be required to meet growing energy demands in North Dakota.

Let me address Coyote. We believe Coyote remains a viable place for future generation expansion. Like Big Stone, as an existing power plant site, it has significant infrastructure already in place which provides it with obvious advantages over a greenfield site. It has adequate water pipeline capacity through our pipeline from the Missouri River.

Issues that will need to be addressed for any expansion at Coyote include fuel quality, but we would anticipate being able to address this in any new plant design. Also, not unlike many existing plants and potential greenfield sites, transmission capacity would have to be expanded. But overall, Coyote remains a very viable expansion opportunity at this time.

With respect to Big Stone Unit II and its impact on North Dakota generation prospects, Big Stone Unit II will actually enhance the prospects for development of generation resources in the state, not only for North Dakota customers but for out-of-state customers as well. One of the primary reasons that Big Stone Unit II could encourage development in North Dakota is because it will expand the capability of the transmission grid. The transmission proposed as part of the Big Stone Unit II project will help alleviate the North Dakota Export constraint, which limits the amount of energy that can be exported from west to east, as Mr. Deason recognized at page 29 of his direct testimony. This additional transmission capacity will be especially useful for accommodating new wind energy, including wind projects to be constructed in North Dakota. Another aspect of the Big Stone Unit II project that will assist future development in North Dakota is the air pollution control equipment that will be installed to minimize emissions of certain pollutants, such as sulfur dioxide, particulate matter, and mercury, from both the new Unit II and the existing Unit I, which will be beneficial to the environment in the region, of course, but will also result in a greater ability to accommodate new emission sources and still meet applicable state and federal requirements.

Q: Does this conclude your rebuttal testimony?

A: Yes.

CASE NOS. PU-06-481 & PU-06-482

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER CORPORATION D/B/A

OTTER TAIL POWER COMPANY

AND

MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC.

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

REBUTTAL TESTIMONY

OF

MARK ROLFES

PROJECT MANAGER

OTTER TAIL POWER COMPANY

JUNE 21, 2007

REBUTTAL TESTIMONY OF MARK ROLFES

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY OF MARK ROLFES

I. INTRODUCTION

Q: What is the purpose of your rebuttal testimony?

A: The purpose of my rebuttal testimony is to respond to various issues raised in the Direct Testimony of Mr. Terry Deason and the Direct Testimony of Mr. David Schlissel. I will provide additional information regarding the efforts and commitments made by the Big Stone co-owners to take into account potential fuel supply and delivery challenges. I will also respond to statements about the potential for increased costs.

II. FUEL SUPPLY ISSUES

Q: Have you had an opportunity to review the testimony of Mr. Terry Deason relating to the supply of coal to Big Stone?

A: Yes, I have read his testimony and I am aware that fuel supply and delivery are important issues relating to the long term operation of Big Stone II.

Q: Have Otter Tail Power, Montana Dakota Utilities, and Northwestern Public Service, the owners of Big Stone Unit I, experienced any fuel delivery problems at the Big Stone facility?

A: Yes. At certain times during the spring of both 2005 and 2006, we did not receive the expected shipments of coal and our supplies diminished to the point that in 2006 we operated at less than normal capacity. This has been the only serious reduction in generation that has been required since the Burlington Northern took over operation in the early 1980's. We have worked with the Burlington Northern Santa Fe Railway ("BNSF") to address this matter. The

BNSF has increased the number of shipments and upgraded a number of its facilities. Mr. Brautovich discusses the Railway's responsive actions in his testimony. The owners have also added a third train set.

Q: At page 37 of his testimony, Mr. Deason describes a number of operational measures that Otter Tail might take to minimize coal delivery problems. Have you begun to implement any of these measures?

A: Yes, we have implemented these operational measures at Big Stone I. The Fuel Supervisor continually monitors train cycle times and uses this information to plan deliveries. Also future delivery needs are projected well in advance. Also part of the changes planned for the coal yard with the addition of Unit II will make it easier to move coal into and out of the coal yard thus making the third suggestion much more practical to implement. Finally Big Stone II has not done the analysis yet regarding the purchase of aluminum cars. I can report that all past analyses have shown the superiority of the lighter cars and the Big Stone II co-owners will seriously consider acquisition of the lighter cars. Also, as Otter Tail's Vice President Ward Uggerud stated in his Rebuttal Testimony, the Big Stone II Co-Owners are committed to follow up on the suggestions by Mr. Deason.

Q: What is the company planning to do about expanding the storage capability to increase the coal inventory target level?

A: We are looking into that issue. We have not decided yet what target level to establish when Big Stone Unit II goes into operation. We have a couple more years of operation of Unit I to rely on before we have to decide on the target level. We have the room on site to

afford more than 30 days supply if we decide that is appropriate. This is a matter that we will continue to investigate and to report on as we follow up with Mr. Deason's recommendations.

Q: At pages 19-21 of his Direct Testimony, Mr. David Schlissel asserts that the Big Stone co-owners have failed to properly consider the risks and the cost impacts of coal deliverability problems. What response do you have?

A: Mr. Schlissel's criticism is unfounded. His basic complaint is that the co-owners have not made the same assumptions he would make in analyzing the various generation alternatives. We are fully aware that fuel supply and delivery disruptions can affect the operation and the cost of the energy produced by the facility. Fuel supply risks will exist regardless of what type of plant is proposed and what kind of fuel is burned. The costs of every type of fuel can go up or down. Mr. Schlissel recognizes at page 21 of his testimony that Burns & McDonnell did look at the potential effect of cost increases on various generation alternatives. The co-owners have responsibly taken into account that the cost of fuel, whatever it is, may go up, and that availability of the fuel is an important consideration. We not only have taken these risks into account, we are addressing the absolute need for a reliable coal supply on a number of fronts, as recognized by Mr. Deason and explained by Mr. Uggerud and me in our testimony.

III. ESTIMATED COSTS

Q: At page 11 of his testimony, Mr. Schlissel states that the Big Stone co-owners, including Otter Tail Power and Montana-Dakota Utilities, have assumed there will be no further capital cost increases in the Big Stone Project before it is completed. Is that right?

A: No, it is not, and I and other witnesses explained that in the Minnesota proceeding. The owners believe, and Black & Veatch has advised, that the capital cost of Big Stone Unit II will increase by approximately 6% per year because of inflation for any delay in the Commercial Operation Date, and there are still final design decisions that we expect will have some minor effect on cost.

Q: Mr. Schlissel asserts at pages 14-15 of his testimony that the cost of Big Stone Unit II has gone up another $199 million. Is that an accurate statement?

A: No, that is not accurate, and I explained the reason why in the Minnesota proceeding. I will reiterate what I said in Minnesota. I believe they got that figure from an August 24, 2006 Black & Veatch document entitled "Owners' Alternatives for Financial Risk Commitments Prior to CON and PSD." In that document, Black & Veatch set forth four possible cases for continuation of the Big Stone II project. Black & Veatch estimated that Case 3 would result in a delay in the in-service date to May 2012. With costs expected to escalate at 6 percent, and with increased project team and Black & Veatch costs, the delay was estimated to add $199 million to the project cost. Black & Veatch subsequently indicated their understanding that the Applicants were electing Case 3. However, the Applicants have had ongoing discussions with Black & Veatch resulting in a project path that differs from the August 2006 Black & Veatch Case 3. In particular, the August Case 3 stated that no activities would be undertaken by Black & Veatch other than as necessary to support permitting, with the result that the earliest procurement (for the boiler) would be issued for bid in October 2007. In contrast, under the present plan the owners have instructed Black &

Veatch to take needed actions to be ready to enter into critical contracts upon receipt of the finial critical permit.

Q: Can you once again state for the record what the co-owners' best estimate for the cost of Big Stone Unit II is?

A: Our best estimate is that Big Stone Unit II will cost $1.361 billion, excluding the cost of transmission, if the in service date is 2011. But for a number of reasons we expect the in service date will be delayed at least one year. We believe this will increase the cost of the plant by 6%. If the in service date is delayed further, we expect the costs to go up approximately $7 million per month.

IV. COMMERCIAL OPERATION DATE FOR UNIT II

Q: Mr. Schlissel asserts at page 13 of his direct testimony that "project documents reveal that that . . . actual commercial operation date for the Big Stone II Project [is] July 1, 2013." Is that right?

A: No.

Q: What is the anticipated commercial operation date for Big Stone II?

A: The actual commercial operation date is dependent on when permitting is complete, which is beyond the direct control of the project. But if permitting is completed later this year as anticipated, we would expect to have commercial operation in mid 2012.

Q: Does this conclude your rebuttal testimony?

A: Yes.

CASE NOS. PU-06-481 & PU-06-482

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER CORPORATION D/B/A

OTTER TAIL POWER COMPANY

AND

MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC.

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

REBUTTAL TESTIMONY

OF

TIMOTHY ROGELSTAD

MANAGER OF DELIVERY PLANNING

OTTER TAIL POWER COMPANY

JUNE 21, 2007

REBUTTAL TESTIMONY OF TIMOTHY ROGELSTAD

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY OF TIMOTHY ROGELSTAD

I. INTRODUCTION

Q: What is the purpose of your rebuttal testimony?

A: The purpose of my rebuttal testimony is to respond to the Direct Testimony of Mr. Terry Deason regarding the proposed new transmission lines and to provide some additional information regarding the benefits realized by the construction of the Big Stone to Granite Falls line at 345 kV capability.

II. 345 KILOVOLT CAPABILITY

Q: Why have the Big Stone co-owners decided to build the Granite Falls line to 345 kV capability?

A: In the course of conducting transmission planning to determine what was needed to interconnect the new Big Stone II facility to the grid, we looked not only at the Big Stone needs but also at how the transmission would fit into other long-range regional plans and at what other transmission needs might be present in the region.

After we completed the initial interconnection studies for the Big Stone Unit II project, we looked at what other transmission needs that could benefit form the Big Stone transmission corridor. We also looked at how the Big Stone Unit II Transmission Interconnection Project fit into long-range regional plans. The CapX 2020 Vision

Plan,[1] for example, identified two 345 kV transmission lines from the Dakotas into Minnesota. The Big Stone to Granite Falls transmission line advances that portion of the CapX 2020 Vision Plan. We also realized, of course, that the Dakotas and southwestern Minnesota were good wind resource areas and we knew that there was not enough transmission available to handle additional amounts of wind energy.

Knowing that a higher voltage line would provide additional transmission for a number of purposes, we began to look at some of the specific impacts of constructing a larger line. Initially, we determined that if the line was going to be larger than needed specifically for Big Stone, a 345 kV capability would be the only likely upgrade. We found that constructing the Granite Falls line to 345 kV capability would not require any significant new right-of-way over the 230 kV line. We determined that line losses would be measurably less with the line operated at 345 kV rather than at 230 kV. And we found that a 345 kV line would cost approximately $25 to $30 million more than a 230 kV line out of a total cost for transmission of approximately $110 million for transmission interconnection costs, and out of a total for both transmission interconnection *and* transmission delivery service facilities of $238 million.

Q: Please briefly explain the distinction between transmission "interconnection service" and transmission "delivery service."

[1] CapX 2020 is an effort of eight Minnesota and regional utilities including Otter Tail, who are putting focus and direction into strengthening the region's high voltage transmission system to better serve growing demand, enhance reliability, and provide generation outlet opportunities. The CapX 2020 Vision Plan is a report that was completed in May 2005, after an extensive planning effort to identify projects that may be needed to meet customer demand well into the future - perhaps as much as 8000 MW of generation. Based on several different hypothetical generation expansion scenarios, the Vision Plan sets forth a proposal for construction of over 1600 miles of 345 kV transmission lines in North Dakota and Minnesota at a cost of over $1.2 billion.

A: *Interconnection service* is access to the necessary transmission lines to safely and reliably allow a generating facility to connect to the grid. Transmission *delivery service* is access to the transmission grid to actually move the energy from the generator to different points on the transmission grid, including delivery of energy from Big Stone Unit II to the co-owners' customers.

Q: Why has a distinction between interconnection service and delivery service developed?

A: The distinction between "interconnection transmission service" and "transmission delivery service" has developed because in 1992, Congress made the wholesale generation market open to free competition – i.e., the Federal Energy Regulatory Commission (FERC), which has jurisdiction over the transmission of electric energy in interstate commerce, would no longer regulate the *sales* of (as opposed to the transmission of) electric energy in interstate commerce. In order to make good on that goal, however, FERC believed it needed to open up the transmission system so that persons who controlled the transmission system (i.e., utilities, who also owned competing generation facilities) could not unfairly discriminate against competitors by keeping them from having "open and comparable access" to the transmission grid. And FERC did just that by adopting Order No. 888 and related orders and rulemakings.

Q: What has been the result of this opening up of the transmission grid?

A: In the evolution of open access, FERC has found that while open access and Order No. 888 resolved for the most part the problems associated with parties obtaining comparable transmission service (i.e., comparable transmission *delivery* service), certain generators were still having difficulties getting access to the grid in the first place – i.e., having difficulty

getting *interconnection* service. Thus the FERC devised a process that utilities must undertake in response to a generator's request for interconnection service. That process requires that utilities (and Regional Transmission Organizations such as the Midwest Independent System Transmission Operator) undertake a study and identify the necessary transmission facilities that would need to be constructed and placed in service before the generator can interconnect to the system.

Q: Are interconnection service requirements and delivery service requirements evaluated separately when a new generating facility is proposed?

A: Yes, the FERC requires that they be evaluated separately, and they have been in this matter. Transmission delivery service requires its own study process, separate from the interconnection study process. And while the study process for delivery service is similar to that for interconnection, the transmission delivery service study process evaluates likely impacts of new generation on the transmission network over a much larger geographical area than does the interconnection study process – i.e., one that includes service to the generator's ultimate customers.

Another important distinction is that there are different "queues" for interconnection service and delivery service. In MISO, requests for interconnection far outnumber requests for delivery service. And the FERC has made clear that obtaining interconnection service does not guarantee delivery service – and vice versa – obtaining transmission delivery service does not guarantee interconnection service.

Q: Is the Big Stone to Granite Falls line part of the proposed interconnection facilities or transmission service delivery facilities?

A: The Granite Falls line is part of the proposed interconnection facilities. We do not anticipate any of the transmission delivery service facilities to be sized at 345 kV standards.

Q: When do the Big Stone co-owners anticipate that the Granite Falls line will be operated at 345 kV?

A: Once Big Stone Unit II goes into operation, the Granite Falls line will operate initially at 230 kV. The co-owners anticipate that a new 345 kV line being proposed by the CapX utilities from southwestern Minnesota through the Granite Falls area and on to the Twin Cities will be constructed and in operation sometime after 2012, and after Big Stone comes online. Once that new 345 kV line becomes available, the Big Stone line can be energized to 345 kV.

Q: Will the Big Stone to Granite Falls 345 kV line become part of the MISO Transmission Expansion Plan (MTEP)?

A: Yes, we believe that MISO will include all of the Big Stone II Transmission facilities in MTEP. At a recent MISO Planning Sub-committee, June 19, 2007, MISO staff indicated that the Big Stone Unit II interconnection facilities will become part of MTEP once an interconnection agreement is signed.

Q: What is the significance if MISO includes the facilities in its MTEP?

A: Once the MISO Board of Directors approves the plan and the facilities in the plan, MISO will have determined that the facilities in the plan are prudent and necessary for providing reliable transmission service. Equally important, by having a transmission project approved in MTEP, cost recovery of those facilities is allowed under the MISO tariff.

Q: What is the co-owners' schedule for constructing the transmission lines?

A: The co-owners intend to bring the Granite Falls online in fall of 2010 and the Morris 230 kV line online in early 2012. Construction will begin with the segment from Big Stone to the Canby substation in Minnesota, followed by the Canby to Granite Falls portion. Completing the Granite Falls line first provides capacity on the system above what is already present to accommodate the fact that the Morris line has to be taken out of service during construction, thus incurring less risk of service interruption to customers served by the Morris line.

Q: Is it prudent to spend the additional money to build the Granite Falls line to 345 kilovolt specifications when a 230 kV line would handle the Big Stone energy output?

A: Yes. Because part of an efficient transmission regional plan is to build one that will facilitate the development of new generation resources in the region, sizing the Big Stone to Granite Falls line at 345 kV is prudent. MISO agrees with this. Regional planning has long identified the need to increase the transmission capability from the Dakota's in order to deliver both new coal and wind resources, including through the findings of regional studies such as the Lignite Vision 21 Transmission study, MISO's Northwest Exploratory Study and the CapX Vision Study. Each of these studies identified the need to build 345 kV transmission facilities from the Dakota's. Building the Granite Falls line at 345 kV advances a portion of those long range plans. If we build just the minimum facilities required to interconnect Big Stone Unit II (i.e., 230 kV line from Big Stone to Granite Falls), we would need to have to build another 345 kV line some place else in the vicinity at 345 kV these long range plans. Building the Granite Falls line at 345 kV is the first step in the build-out of an

efficient transmission system from the Dakota's, one of the primary purpose of which is to enhance the ability of adding new generation in the Dakotas.

Q: At page 29, line 13, of his testimony, Mr. Deason is referring to your direct testimony when he states: "… the transient stability problem that arises when large amounts of generation are connected to distant loads with less than optimal transmission." Do you believe there is less than optimal transmission in the region?

A: No, from the perspective of the existing system, the system has been optimized. However, from the perspective of adding additional generators to the transmission system, there will need to be additional transmission necessary to optimize the system. With the Big Stone Unit II transmission plan, we have developed an optimal plan that takes into consideration some of the regional needs. I believe Mr. Deason may have misinterpreted my statement of a weak transmission system as meaning less than optimal, and that is not what I intended. A weak transmission system can be adequate, but a weak system will need to be expanded to add more generation or load.

Q: Does this conclude your rebuttal testimony?

A: Yes.

CASE NOS. PU-06-481 & PU-06-482

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER CORPORATION D/B/A

OTTER TAIL POWER COMPANY

AND

MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC.

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

REBUTTAL TESTIMONY

OF

KERMIT TROUT

VICE PRESIDENT – SENIOR PROJECT MANAGER

BLACK AND VEATCH CORPORATION

JUNE 21, 2007

REBUTTAL TESTIMONY OF KERMIT TROUT

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY OF KERMIT TROUT

I. INTRODUCTION

Q: At page 7 of Direct Testimony filed on behalf of Mark Trechock and Dakota Resource Council ("DRC") in this proceeding, David A. Schlissel notes there are risks and uncertainties associated with building "fossil plants," including coal and natural gas fired plants, and also risks and uncertainties associated with renewable alternatives. Do you agree with Mr. Schlissel that risks and uncertainties attend each approach to power supply planning?

A: Yes.

Q: Do you agree with Mr. Schlissel that the Big Stone II Project owners failed to consider the risks and uncertainties regarding the potential for further capital cost increases affecting the Project?

A: No.

Q: Please explain your answer.

A: The Big Stone II Project owners have included allowances for escalation of capital costs as well as allowances in the form of contingencies for those risks and uncertainties. While it is difficult to predict actual escalation and cost increases, reasonable allowances for both have been included in the capital cost estimates.

Q: Mr. Schlissel asserts that the Big Stone II Project owners, including Otter Tail Power Company ("Otter Tail") and Montana-Dakota Utilities ("Montana-Dakota") have skewed the results of their capital cost analyses by failing to recognize that the

impact of the factors that have led to increases in the estimated costs of Big Stone II will not be as great in the case of alternatives to Big Stone II, such as natural gas and renewables, including wind. Do you agree with this assertion?

A: No.

Q: Please explain your answer.

A: The factors that impacted the increases in the estimated costs of Big Stone II, such as engineered equipment price increases, commodity price increases, and labor increases for example, will impact all types of generating plants. All power projects use engineered equipment, commodities like copper and steel, and labor for constructing the plants.

Q: At pages 18 - 19 of his Direct Testimony, Mr. Schlissel attempts to paraphrase Black & Veatch's cost analyis by saying, "However, Black & Veatch further explained that simple cycle and combined cycle equipment costs have remained steady because the demand for combustion turbines 'is relatively low'." Is this a fair summary of your analysis?

A: No. Mr. Schlissel's statement needs quite a bit of additional context for it to be understood as anything but misleading. It is true that the costs of <u>some</u> components of simple and combined cycle natural gas "equipment" have not increased at the same rate that costs have increased for the major components of large pulverized coal-fired plants. The implication, however, that natural gas plants have not experienced dramatic cost increases is simply wrong. In addition, Mr. Schlissel notes that the labor cost element of the capital cost of a new natural gas plant is low relative to the labor cost component of a coal plant. While this point is true in isolation, in the overall scheme of things it can lead to wrong conclusions.

Q: Why do you say that?

A: The difficulty with comparing the future capital and busbar costs of alternative generating resources is, as Mr. Schlissel acknowledges, uncertainty. Estimating such costs is, inherently, an exercise in speculation and the application of one's best judgment based on history, experience and existing conditions. Magnifying the problem is the fact that conditions change over time, in many cases, over relatively short periods of time. Thus, we know today that if the Big Stone II Project owners decided to build a 630 MW CCGT plant instead of a 630 MW supercritical pulverized coal plant, their labor and equipment costs likely would be lower, but over the long-haul, their fuel costs would be dramatically higher. Whether these costs differentials would be great enough on a present value basis to justify switching to a natural gas project involves the exercise of one's best professional judgment. I find it significant that Mr. Schlissel has not advocated, and is not advocating here, that the Big Stone II Project owners build a natural gas plant instead of a supercritical pulverized coal plant.

Q: What market conditions have led to increases in the estimated costs of renewable supply-side alternatives such as wind, which Mr. Schlissel references at page 18 of this direct testimony?

A: The increased demand for the wind turbine technology has created some of the same market conditions as with other engineered equipment; that is, the demand for that equipment has put pressure on the manufacturing capacity. In addition, cost increases are due to several other factors:

– Euro/Dollar exchange rate, as most wind turbines are manufactured in Europe

– Steel/Concrete/Copper price increases

– Transportation Costs (Oil)

-- General increases in construction costs.

Q: Could you provide Black & Veatch's current assessment of the relative capital costs of wind turbines and supercritical coal plants adjusted for capacity factor and expected useful life?

A: No. An answer to this question as raised wouldn't be practical. It's like mixing apples (capital costs) with oranges (operating costs) directly. However, by making various assumptions, busbar cost or life-cycle cost comparisons (which is what the BSP II owners have done) can be made to include operational factors such as capacity factor and useful life with initial capital costs. Those life cycle type of analyses provide a better comparison than relative capital costs.

Q: It has been nearly six months since you testified in the Minnesota transmission Certificate of Need proceeding. Have market conditions affecting the cost of the major components of the Big Stone II plant materially changed since you testified?

A: While no specific assessment has been completed in the last few months, I believe that the allowances included previously for escalation and contingency are still valid. Nothing from a cost estimate impact has materially changed since then.

Q: Does this conclude your testimony?

A: Yes.

CASE NO. PU-06-481/482

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER CORPORATION D/B/A

OTTER TAIL POWER COMPANY

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

AND

IN THE MATTER OF THE APPLICATION BY MONTANA-DAKOTA UTILITES CO., A DIVISION

OF MDU RESOURCES GROUP, INC.

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

REBUTTAL TESTIMONY

OF

JEFF GREIG

GENERAL MANAGER, BUSINESS & TECHNOLOGY SERVICES

BURNS & MCDONNELL

JUNE 21, 2007

REBUTTAL TESTIMONY OF JEFF GREIG

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY OF JEFF GREIG

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Jeffrey (Jeff) J. Greig. My business address is Burns & McDonnell Engineering Co., 9400 Ward Parkway, Kansas City, MO, 64114.

Q: By whom are you employed, and in what capacity?

A: I am employed by Burns & McDonnell Engineering Company. I am the General Manager of the Business & Technology Services Division of the company.

Q: What are your responsibilities in your current position?

A: The Business & Technology Services Division is a consulting group specializing in generation resource planning, transmission planning, financial and rate analyses, project development services, information management and technology consulting, security consulting, and energy services. We consult with utilities, government agencies, and private companies.

Q: What is your educational background?

A: I have Bachelors Degrees in Finance and Economics from Eastern Illinois University, and a Masters Degree in Economics from Iowa State University.

Q: What is your employment history?

A: I have 20 years of experience as a consultant in the electric power industry. My background includes generation resource planning, feasibility studies, siting studies, market assessments, project development, and asset due diligence.

Q: Have you provided written testimony in other state proceedings regarding the proposed Big Stone Unit II?

A: Yes I did. I provided testimony before the South Dakota, and the Minnesota Public Utilities Commission regarding the Big Stone Unit II project and proposed transmission interconnection facilities. My testimony here is based in part on my previous work and testimony in those states.

Q: Have you testified in other proceedings related to large energy facilities?

A: Yes. I have provided written and oral testimony before the Wisconsin Public Service Commission regarding a site certificate for a gas-fired project. I have provided written and oral testimony before the Ohio Power Siting Board regarding a site certificate for a gas-fired project. I have prepared written testimony regarding a site certificate and rate principles filing presented to the Iowa Utilities Board. I have prepared written testimony regarding power supply planning for the New Mexico Public Regulation Commission. I have prepared written testimony regarding a generation asset transfer for the Illinois Commerce Commission, and I have provided written and oral testimony regarding a generation asset transfer for the Federal Energy Regulatory Commission (FERC).

II. PURPOSE AND SUMMARY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to explain the analysis that Burns & McDonnell did to evaluate the economics of various baseload generation technologies and to describe the results of that analysis and to respond to certain points raised by Mr. Terry Deason in his Direct

Testimony. I also explain some errors in Mr. Schlissel's testimony about the Burns & McDonnell work.

Q: Please summarize your testimony.

A: Burns & McDonnell was hired by the Big Stone co-owners to evaluate the economies of various baseload generation technologies. Burns & McDonnell developed capital cost, performance, and O&M cost estimates for the different technologies in the initial studies. These cost estimates were input into an economic model to determine the cost of generating a unit of electricity for each baseload technology. We determined that a supercritical pulverized coal plant, like Big Stone Unit II, represented the lowest cost baseload generation technology for both investor-owned and publicly-owned utilities of the technologies considered.

We also prepared a subsequent report in October 2006 with updated costs to determine the busbar cost for three different baseload generation options: a 630 MW Big Stone Unit II supercritical pulverized coal plant, a 500 MW combined cycle gas turbine ("CCGT") plant, and a 500 MW combination CCGT plus market purchases of wind energy. We utilized the most recent cost estimates prepared by Black & Veatch. Our updated analysis continued to demonstrate that the Big Stone Unit II supercritical pulverized coal plant has the lowest busbar costs on a $/MWh basis of the three options, for both investor-owned utilities and public power utilities.

I respond to the issues raised by Terry Deason in his testimony, where he compares the Burns & McDonnell work with analyses completed by James Heidell for Montana-Dakota. I do not find that there are any serious inconsistencies between our work and Mr.

Heidell's work, and indeed, the fact that we both reach the same conclusion under different assumptions, strengthens the conclusion that Big Stone Unit II is a least cost alternative.

In order to clarify some misstatements by Mr. Schlissel about our analysis of the estimated costs of the Big Stone project and a natural gas/wind combination alternative, I explain how we did our analysis and that our assumptions regarding the size of a natural gas plant as an alternative to Big Stone and the value of the Production Tax Credit were appropriate.

III. ROLE OF BURNS & MCDONNELL

Q: What role did Burns & McDonnell play in evaluating the Big Stone proposal?

A: Burns & McDonnell conducted three separate studies for the proposed Big Stone Unit II owners to evaluate the economics of various technologies for generating electricity. As part of the Applicants' due diligence to construct Big Stone Unit II, Otter Tail Power Company ("Otter Tail") asked Burns & McDonnell to conduct a first study, referred to as the Phase I study, to examine several different technologies for generating baseload electricity. As part of that study, Burns & McDonnell developed capital cost, performance, and O&M cost estimates for the different technologies. Of the technologies considered, the Phase I study recommended that a supercritical pulverized coal plant, such as Big Stone Unit II, represented a low cost generation technology.

Burns & McDonnell utilized the work from the first study to conduct a second study, called "Analysis of Baseload Generation Alternatives – Big Stone Unit II" ("Baseload Generation Alternatives Study") in which an expanded set of generation alternatives, including integrated gasification combined cycle (IGCC) technology, were evaluated. The

Baseload Generation Alternatives Study confirmed that a 600 MW pulverized coal plant represented the lowest cost baseload generation alternative. A copy of this report was included as Exhibit MR-1 attached to the Direct Testimony of Mark Rolfes.

Finally, Burns & McDonnell updated the busbar cost analysis for three different generation options: the 630 MW Big Stone Unit II supercritical pulverized coal plant, a 500 MW combined cycle gas turbine ("CCGT") plant, and a 500 MW combination CCGT plus market purchases of wind energy. We utilized the most recent cost estimates prepared by the project's design engineer Black & Veatch. Our updated analysis continued to show that the Big Stone Unit II supercritical pulverized coal plant has the lowest per MWh busbar costs of the three options, for both investor-owned utilities and public power utilities. This report, entitled "Revised Analysis of Baseload Generation Alternatives" ("Revised Baseload Analysis") dated October 2, 2006, was also attached to the Direct Testimony of Mark Rolfes, Exhibit MR-2.

Q: What cost and performance assumptions were used by Burns & McDonnell in the Revised Baseload Analysis?

A: The capital cost estimate provided to Burns & McDonnell by Otter Tail for the Big Stone Unit II project was $1.366 billion excluding transmission construction. The net output of the Big Stone Unit II project was a nominal 630 MW net to reflect the new estimate of the dependable capacity that will be available from the project, and the net heat rate was estimated at 9,095 Btu/kWh.

Q: What were the cost and performance assumptions provided to Burns & McDonnell for the CCGT project?

A: Black & Veatch prepared a report entitled, "Supply-Side Technology Study" dated August 2006. The capital cost estimate for a generic 2 x 1 GE 7FA CCGT project was estimated in 2006$ at $281 million ($562/kW) plus $56.2 million of owner's costs. The net output of the CCGT project was 500 MW net, and the net heat rate was estimated at 6,704 Btu/kWh.

Q: Does the difference in size between the 630 MW supercritical PC unit and the 500 MW CCGT unit materially impact the results?

A: No. The nominal size of the supercritical PC unit and the CCGT unit are common block sizes of the technologies that are employed in the market. The economic evaluation was prepared on a busbar basis and expressed in terms of $/MWh of energy production. This allows the results to be compared directly. The objective of the Revised Baseload Analysis was to update the results for recent cost estimates and the nominal 630 MW supercritical PC unit and 500 MW CCGT unit cost estimates prepared by Black & Veatch were the most recent cost information available at the time.

Q: What was the basis for the cost of wind resources used in the Revised Baseload Analysis Report?

A: For the CCGT plus market purchase of wind energy alternative, it was assumed that non-firm wind energy would be purchased from independent power developers at a levelized cost of $60/MWh for a 2012 in-service date. These purchases would displace an equivalent amount of energy that would otherwise be generated at the CCGT. The $60/MWh does not

include the current federal Production Tax Credit ("PTC"). While the PTC was renewed in 2007 for one year, it may not be available in 2012 as a subsidy to lower the cost of wind energy. Burns & McDonnell estimated that current new wind farm development in the Midwest region costs $40/MWh in 2006 with the PTC in place. This compares with the $36/MWh estimated as 2005$ costs in the original Baseload Generation Alternatives Study. The price of wind turbines has increased significantly within the last two years due to material costs such as steel and copper, and market factors. Assuming a conservative escalation rate of 2.5% per annum in the cost of wind farms, the estimated 2012 cost of wind energy is $46.39/MWh if the PTC is extended. Both scenarios were evaluated.

Q: Mark Rolfes has testified that the cost of Big Stone II will increase by 6%/year if the in-service date of the plant is delayed. Does your 2.5%/year assumption for wind generation mean that the cost of wind farms is increasing slower than Big Stone II costs?

A: No. We expect the busbar $/MWh costs of wind energy and other alternatives will be largely affected by the same global market pressures on materials and labor that Big Stone II will experience. My point is that, even using a conservative 2.5% per annum escalation rate on the cost of wind generation, Big Stone II is still the cost-effective choice. If I had used a higher escalation rate assumption for wind generation, Big Stone II would have looked even better.

Q: What was the purpose of including the wind resource with the CCGT alternative?

A: For the CCGT project plus wind case, the 500 MW CCGT plant is the baseload alternative being compared to the supercritical PC plant. Both are reliable, dispatchable

generation resources that can be operated to meet baseload capacity and energy requirements. Wind is not a baseload resource because it does not produce dependable generation year-round at high capacity factors. Hence, our analysis did not assume construction of a wind resource. The wind component was added to the CCGT project alternative to enhance its economic performance by displacing higher cost gas-fired energy production with non-firm wind energy when available. The evaluation was focused on comparing baseload project alternatives, not developing combinations of resources on a system basis as a substitute for utility resource planning efforts.

Q: What was the assumption regarding the capacity factor of the wind resource?

A: The evaluation assumed that non-firm wind energy would be available to displace the equivalent of a 40 percent capacity factor for the CCGT plant. In this regard, the assumption was optimistic for typical wind farm production. Nevertheless, we utilized the 40 percent estimate to be conservative in testing Big Stone Unit II's economics against alternatives.

Q: What is the impact of the PTC on the price of wind power?

A: The value of the PTC in reducing wind costs is approximately $22/MWh in most applications. We have reflected a cost of wind of $60/MWh in 2012 in the absence of the PTC in an effort to be more than fair in our assumptions regarding how the wind energy market may react in the future to the expiration of the tax credit. The expiration of the PTC could result in the cost of new wind development being $66/MWh or higher in 2012.

Q: Were the financing assumptions in the Revised Baseload Analysis for the two different ownership structures the same as used in the prior studies?

A: Yes.

Q: Were the other key operating and economic assumptions the same?

A: Yes, with the exception that the fuel cost forecasts were updated based on 2006 information.

Q: What was the basis for the fuel cost forecasts used in the October 2006 Revised Baseload Analysis?

A: The Powder River Basin ("PRB") fuel cost forecast was provided by Otter Tail. Initially we used a cost of $1.31/MMBtu in 2011. In this round of examination, we used a cost of $1.71/MMBtu in 2010 for the overall delivered cost for PRB coal.

For natural gas, in September 2006, the NYMEX futures price for Henry Hub natural gas commodity supply in 2011 was $7.20/MMBtu. A conservative transportation cost of $0.40/MMBtu was added to this supply cost for a delivered cost of $7.60/MMBtu in 2011.

Q: What were the specific results reported in the Revised Baseload Analysis?

A: For the public power utility ownership model, the lowest cost generation alternative was the 630 MW supercritical Big Stone Unit II project with an estimated levelized busbar cost of $56.38/MWh over the 2012 to 2031 planning period. The CCGT plus market purchases of the wind energy alternative was $77.77/MWh, which is 38% higher than the Big Stone Unit II project. For the investor-owned utility ownership model, the lowest cost generation alternative was also the 630 MW supercritical Big Stone Unit II project with an estimated levelized busbar cost of $69.62/MWh over the 2012 to 2031 planning period. The CCGT plus market purchases of the wind energy alternative was $80.78/MWh, which is 16% higher than the Big Stone Unit II project.

IV. RESPONSE TO TERRY DEASON TESTIMONY

Q: At page 15 of his testimony, Mr. Terry Deason indicated that it was not clear why in the CCGT + Wind alternative, Burns & McDonnell assumed the wind component would be a power purchase. Can you explain that assumption?

A: Yes. There were two primary reasons for this assumption. First, the majority of wind generation developed in the U.S. has been implemented by independent power producers and sold to electric utilities under power purchase agreements. So this assumption reflects how the industry has currently evolved for the most part. Secondly and more importantly, we were preparing an analysis that could be used by both investor-owned utilities and public power utilities since this was consistent with the types of ownership entities involved in the Big Stone II project. We wanted to capture the value of the current production tax credit. Since public power utilities are generally tax-exempt utilities, the assumption that the wind component was developed by an independent power producer that could take full advantage of the current PTC – i.e., a developer with a full tax appetite - was reasonable.

Q: Mr. Deason continued at page 15 of his Direct Testimony that there may be an inconsistency between the cost estimate and escalation rate for wind assumed by Burns & McDonnell and the assumptions in that regard made by Mr. Heidell in Montana-Dakota's Generation Expansion Plan Analysis? Is there an inconsistency?

A: Yes, apparently there is an inconsistency. We have estimated that the cost of wind will increase, and Mr. Heidell has assumed that it will decrease.

Q: Does that inconsistency change any of your conclusions?

A: No it does not. Indeed, the fact that Montana-Dakota's Generation Expansion Plan Analysis was based on a declining capital cost for wind and still recommended the inclusion of the Big Stone II project in the generation expansion plan only strengthens the conclusion that Big Stone is least cost, since under both higher wind capital cost assumptions and lower cost assumptions, Big Stone II still comes out as least cost.

It may not have been unreasonable to assume that costs may decline at the time of Montana-Dakota's analysis. There had been some cost reduction in the 2002-2006 timeframe in the industry. However, I continue to believe that the cost of wind will increase in the next few years. The significant amount of wind development currently ongoing in the U.S. and around the world combined with significant cost escalation in labor and key material commodities such as steel and copper have caused price increases in the costs of installing new wind generation, not decreases. Several of the prominent manufacturers of wind turbines such as GE, Seimens, Vestas and Mitsubishi are currently sold out of manufacturing capability until 2009. The high market demand for these units plus the significant cost escalations that have impacted all types of generation projects, including wind, have increased wind costs recently and we believe there are no fundamental drivers in place that would mitigate these factors. Burns & McDonnell believes the assumption of only a 2.5% annual escalation in the current cost of wind generation is conservative.

Q: In his testimony at pages 15-16, Mr. Deason points out that another potential inconsistency between Burns & McDonnell and Montana-Dakota is the assumed capacity factor for wind generation. Is there any inconsistency here?

A: I don't believe so, because as Mr. Deason correctly notes, the assumptions reflect different factors. Burns & McDonnell's assumption of a 40% capacity factor from the wind component is used to reduce the amount of higher cost gas-fired generation from the CCGT plant. The 40% capacity factor assumption is conservative for wind generation performance. Mr. Heidell's assumption references the expected capacity contribution of wind generation during Montana-Dakota's peak. It may or may not be consistent with Burns & McDonnell's 40% overall capacity factor assumption.

Q: Yet another apparent inconsistency pointed out by Mr. Deason related to the capacity benefits for wind. Did Burns & McDonnell assume no capacity contribution for the wind component in the CCGT + Wind alternative?

A: No, I don't agree with the characterization that the wind component was expressly assumed to have no capacity value. I need to explain the purpose of our studies and the results to understand why this is a misconception of our work.

First, the purpose of our analysis was to compare the economics of baseload generation alternatives. In the CCGT + Wind alternative, the CCGT plant is the baseload alternative being compared to the Big Stone II project, not the wind energy purchase. Both plant alternatives – i.e., both the super-critical coal plant and the natural gas CCGT - offer firm, reliable, dispatchable capacity that can be operated at a high capacity factor to provide energy. A *non-firm* wind component was added to enhance the overall economics of the CCGT project by displacing higher cost gas-fired energy. It was not the purpose of our studies to replace utility resource planning efforts that would evaluate a number of supply-side and demand-side resources in combination that could meet a utility's overall capacity and

energy needs. Both Otter Tail and Montana-Dakota conducted separate resource planning analysis and that information, as I understand, has been introduced in this proceeding.

Second, Burns & McDonnell has noted concerns about assuming that the wind component in the CCGT + Wind case should have a firm capacity value without addressing transmission costs. The Baseload Generation Alternatives Study included a busbar analysis. It is reasonable to compare the busbar costs of a similar sized coal unit such as Big Stone II with a gas unit such as a CCGT plant. However, it is not reasonable to assume that hundreds of MW of wind generation should be combined with the CCGT plant with no additional transmission upgrade costs for the wind component added.

Finally, Burns & McDonnell did prepare an economic analysis assuming a 15% capacity value is assigned to the wind component in the CCGT + Wind case (even though no additional transmission costs were included). The results of this analysis indicated no change in the conclusion that the Big Stone II project remained a lower cost alternative, and the overall costs of the CCGT + Wind case actually changed very little. This case is driven by the high costs of gas-fired generation and not capacity value assumptions for wind (even incorrectly ignoring transmission impacts).

Q: Finally, at pages 19-20 of his testimony, Mr. Deason questions whether Burns & McDonnell and Montana-Dakota have made inconsistent assumptions regarding the future price of natural gas. Can you clarify this point for us?

A: I do not know the specific detail of how Mr. Heidell or PA Consulting made their natural gas cost forecasts, but the difference is likely explained by the timeframe in which the two analyses were prepared. Mr. Deason correctly notes that forecasting fuel costs is

difficult, particularly for a volatile commodity such as natural gas. Burns & McDonnell believes its natural gas cost forecast remains reasonable, but also recognizes that the PA Consulting forecast could also be viewed as reasonable at the time it was prepared. Significantly, under both cost forecasts, the conclusion reached is that the Big Stone II project is a lower cost baseload alternative.

I can explain how we made our forecasts. Burns & McDonnell referenced the NYMEX natural gas futures pricing as a base point for its forecast. In the original Baseload Generation Alternatives Study prepared in September 2005, the price for natural gas was estimated at $7.00/MMBtu for 2011. In the Revised Baseload Analysis prepared in October 2006, the NYMEX futures for natural gas commodity was $7.20/MMBtu for 2011. A transportation component was added in both analyses. For comparison, the 2011 NYMEX futures for natural gas is $8.16/MMBtu in June 2007, a 13% increase from less than one year ago. Natural gas prices have continued to rise in the futures market, and it is not unexpected that price forecasts at different times can be different.

V. RESPONSE TO DAVID SCHLISSEL TESTIMONY

Q: In the testimony of David Schlissel on behalf of the Dakota Resource Council at page 71, he claims that Burns & McDonnell biased the CCGT + Wind alternative in the Analysis of Baseload Generation Alternatives studies by assuming that a 600 MW natural gas-fired combined cycle facility would be required to backup the wind component. Is this correct?

A: No, Mr. Schlissel continues to try and mischaracterize the Burns & McDonnell Baseload Generation Alternatives Study. No where in the report does it state that 100%

backup capacity is required for wind generation. As outlined earlier, the purpose of the analysis was to compare *baseload* alternatives. The two baseload alternatives under comparison were the coal-fired Big Stone II project and a gas-fired CCGT plant. Those alternatives are directly comparable as both are capable of providing firm, reliable, baseload capacity to a system. Wind is not a baseload resource. However, wind energy was incorporated into the CCGT + Wind alternative on a non-firm basis to reduce the need to dispatch the higher cost gas resource when wind energy was available. Mr. Schlissel tries to characterize the alternative as a wind alternative with gas-fired backup, which is incorrect. It is gas-fired capacity with supplemental, non-firm wind to lower energy costs. The results indicated that the proposed Big Stone II project was a lower cost baseload alternative than the CCGT + Wind case, with or without an extension of the federal PTC included in the cost of wind.

Q: In Mr. Schlissel's direct testimony, he states that assuming a 100% capacity backup natural gas plant is required is inconsistent with Otter Tail's 2006-2020 Resource Plan, which credits wind with a capacity value of approximately 15 percent in the summer and approximately 20 percent in the winter. Does this imply Burns & McDonnell should have incorporated a capacity value into their analysis?

A: No. First, let me emphasize that the purpose of our baseload generation alternatives studies was to compare the economics of baseload generation alternatives. Within the CCGT + Wind alternative, the wind component was added as a non-firm energy resource to lower the overall costs. As indicated, Burns & McDonnell did not prepare resource planning studies for each of the utilities that evaluated a combination of supply-side and demand-side

resources. Each of the utilities prepared additional generation expansion evaluations with underlying assumptions regarding supply side alternatives. Each of those more comprehensive analyses confirmed the Big Stone II project as part of the recommended generation expansion plan.

The assumption that the wind component in the CCGT + Wind case should have a firm capacity value assumes that transmission capacity exists for delivery of wind energy to the utility's load. The Baseload Generation Alternatives Study was based on a busbar analysis comparison of alternatives. It was reasonable to compare the busbar costs of a similar sized coal unit such as Big Stone II with a gas unit such as a CCGT plant. However, Mr. Schlissel argues that hundreds of MW of wind generation should be combined with the CCGT plant and receive capacity credit, but no additional transmission upgrade costs for the wind component need to be added to the analysis. In fact, on page 73 of his direct testimony, Mr. Schlissel is critical of the study results of combining 600 MW of CCGT capacity with 600 MW of wind. He argues that a case with 800 MW or 1,200 MW of wind should have been studied, and that wind should have received a capacity credit. But he ignores the cost impact 1,200 MW of wind would have on transmission upgrades in order to receive capacity credit.

Q: Did Burns & McDonnell prepare any analyses that assumed wind was assigned a capacity value?

A: Yes. In order to evaluate the Mr. Schlissel's claim that the capacity value assumption was a material bias in the study, Burns & McDonnell waived the above criteria in an evaluation presented in the South Dakota hearing. An analysis was prepared assuming a 15%

capacity value is assigned to the wind component in the CCGT + Wind case (even though no additional transmission costs were included), and a smaller capacity of gas-fired generation is constructed. The results of this analysis indicated no change in the conclusion that the Big Stone II project remained a lower cost alternative, and the overall costs of the CCGT + Wind case actually changed very little.

Q: In his direct testimony, at page 74, Mr. Schlissel states that Burns & McDonnell understates the levelized value of the PTC at $12/MWh. Do you believe that you have understated the levelized value of the PTC?

A: No. Mr. Schlissel has used the fact that Burns & McDonnell reflected conservative assumptions regarding the cost of wind without the PTC to draw incorrect conclusions. In the September 2005 Baseload Generation Alternatives Study, the 2005$ cost estimate for wind was assumed to be $38/MWh with the PTC, and $50/MWh without the PTC. In the Revised Baseload Analysis prepared in October 2006, the 2012$ cost for wind was estimated at $46.39/MWh ($40/MWh in 2006$ escalated 2.5% annually) with the PTC and $60/MWh without the PTC. Burns & McDonnell reflected lower values for the cost of wind without the PTC to be conservative in the analysis. Mr. Terry Deason recognized in his testimony on page 14 that a value of $66/MWh for the cost of wind without the PTC was justified.

If these higher values were used, the economics of the Big Stone II project relative to the CCGT + Wind case would improve if the PTC expires as scheduled and is not extended. If Mr. Schlissel is suggesting that the $23/MWh - $28/MWh figures quoted in his testimony should be subtracted from the $60/MWh wind cost estimate, to result in a 2012$ cost of

$32/MWh - $37/MWh assuming the PTC is extended, he is displaying a fundamental lack of understanding of generation resource costs and would be misleading the Commission.

Q: On page 74 Mr. Schlissel states that the September 2005 Baseload Generation Alternatives Study did not include the currently estimated cost of the Big Stone II Project and/or any greenhouse gas regulations. Is this correct?

A: No. The September 2005 Baseload Generation Alternatives Study included the current cost estimate of the Big Stone II project and other resources available at that time. In the October 2006 Revised Baseload Analysis, the cost estimate of the Big Stone II project and other resource alternatives was updated based on the best available information at that time. Both studies included an evaluation of greenhouse gas costs that are consistent with the adopted regulatory values of the Minnesota Public Utilities Commission.

Q: Does this conclude your rebuttal testimony?

A: Yes.

CASE NO. PU-06-481

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER CORPORATION D/B/A

OTTER TAIL POWER COMPANY

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

REBUTTAL TESTIMONY

OF

BRYAN MORLOCK

MANAGER OF
RESOURCE PLANNING

OTTER TAIL POWER COMPANY

JUNE 21, 2007

REBUTTAL TESTIMONY OF BRYAN MORLOCK

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY OF BRYAN MORLOCK

I. INTRODUCTION

Q: Have you previously filed testimony in this matter?

A: Yes, I filed direct testimony on December 1, 2006. In that testimony I explained Otter Tail's Resource Planning efforts, including our use of the IRP-Manager software tool, described our efforts to forecast our future power and energy demands, and identified the company's generation needs and resources.

Q: Have you filed testimony with regard to the Big Stone project in other proceedings?

A: Yes, I filed testimony both before the South Dakota Public Utilities Commission in its Energy Conversion Facility Permit matter and the Minnesota Public Utilities Commission regarding the Certificate of Need for the high voltage transmission lines proposed to interconnect Big Stone Unit II to the grid. In the Minnesota proceeding, I actually filed written testimony on four occasions, once in rebuttal to Mr. Schlissel's prefiled testimony.

Q: Have you had an opportunity to review the Direct Testimony of Mr. David Schlissel filed on May 31, 2007 on behalf of the Dakota Resources Council?

A: Yes, I have reviewed Mr. Schlissel's testimony.

Q: Can you respond to Mr. Schlissel's complaints and arguments about Otter Tail's resource planning efforts and the decision to select the Big Stone II project?

A: Yes, his arguments are essentially the same ones he made in the South Dakota proceeding and in the Minnesota proceeding and to which I have responded before. As I

indicated in these other proceedings, Mr. Schlissel's statements and conclusions about our resource planning efforts are invalid and incorrect.

II. IRP-MANAGER CAPACITY EXPANSION MODEL

Q: Mr. Schlissel states at page 56 of his testimony that the IRP-Manager computer model has significant limitations and that Otter Tail is in the process of changing to another model. Can you respond to that statement?

A: Mr. Schlissel attempts to disparage the IRP-Manager computer model by pointing out certain drawbacks in the model, drawbacks I might add that Otter Tail itself has identified. However, these drawbacks do not affect the ability of the model to analyze resource options; they only make the use of the model more cumbersome than it might otherwise be. For example, the IRP-Manager model requires long periods of time to complete an analysis due to slow model-run times and is incompatible with spreadsheets, which requires data to be inputted manually. It is important to recognize the difference between productivity issues and quality issues.

Otter Tail has used the IRP-Manager model for all of its resource plans, including the first one filed in 1992. The Minnesota Public Utilities Commission has found the IRP Manager to be a legitimate capacity expansion planning tool for integrated resource planning. The Minnesota Department of Commerce, who has been involved in all of Otter Tail's resource planning efforts, stated in a proceeding involving a Resource Plan filed by a municipal utility that "A capacity expansion model (for example, Northern States Power d/b/a

Xcel Energy's use of the Strategist model or Otter Tail Power Company's use of the IRP-Manager model) has advantage over a production cost model."[1]

Otter Tail is and always has been in a unique position with this model. Otter Tail helped to fund the development and provided assistance in the development of the model originally. This included helping to scope out some of the functionality in the model with respect to load management and conservation, due to the Company's significant experience in those areas. Otter Tail also conducted a considerable amount of the testing of the model. As part of this effort Otter Tail received a perpetual license for IRP-Manager. While the original vendor is no longer in existence, the personnel that worked on the model have been available and Otter Tail has hired them several times in recent history to make upgrades to the model. The most recent upgrade was in 2004, just prior to beginning work on the current resource plan. The Otter Tail version of the model has been maintained and is a valid representation of Otter Tail's system.

Otter Tail is in the process of changing to the Strategist model, but only because of productivity issues. Otter Tail is working with the Strategist vendor, New Energy Associates, to develop the database and benchmark the Strategist model to IRP-Manager, which New Energy Associates feels is critical to the process. Strategist will bring better input and output data handling capabilities, and provide some greater flexibility. It has the potential to reduce model run times, but computer run-time improvements will be limited. The model is still expected to take 3 – 5 days to complete an optimization run.

[1] Comments of the Department of Commerce, November 8, 2005, Docket No. ET01/RP-05-1102 (Missouri River Energy Services Resource Plan 2006-2020

Q: Mr. Schlissel asserts that Otter Tail has biased its modeling results against wind. What is your response to his assertion?

A: Mr. Schlissel has raised two concerns about the manner in which we modeled for wind. One has to do with the model's inability to handle tax incentives for wind and the other has to do with whether Otter Tail would own the wind projects or just purchase the power. As explained below, neither concern results in any biases against wind.

There isn't a planning model in existence that can automatically completely model the production tax credit (PTC) and all of the various state level incentives regarding wind generation. The Strategist model which Synapse, (the organization Mr. Schlissel works for), acquired to conduct its own modeling, cannot do it either. It requires manual calculation and input of those parameters because the model cannot automatically do those. And importantly, Mr. Schlissel's confidence that certain tax incentives will be available for wind in five or six years time and beyond is not one that I share.

Mr. Schlissel's suggestion at page 58 of his testimony that Otter Tail's assumption that it would purchase any wind power it required rather than own the turbines biases the results in favor of Big Stone Unit II and against wind is unfounded and unrealistic. In our resource plan, Otter Tail and the Minnesota Department of Commerce discussed whether there was a preference for modeling the wind generation as a Power Purchase Agreement or as ownership. The Department did not have a preference, and modeling as a PPA was clearly easier than modeling as ownership. In addition, modeling as a PPA is more in line with Minnesota policy to promote local ownership of renewable energy sources like wind.

A PPA also is an approach to wind development that can more readily allocate some of the risks associated with wind ownership by purchasing the power. Ownership of wind generation, just like ownership of other resources, has intrinsic and significant risks. A wind farm owner assumes literally all of the risks of ownership, including technology risk, maintenance and failure risk, wind variability risk, and curtailment risk. Under the purchase scenario, the utility is able to allocate some of the risk to the wind farm owner.

Otter Tail has recently announced a partial ownership in the Langdon Wind Center project, so Mr. Schlissel's testimony that Otter Tail has failed to consider ownership is unfounded.

Mr. Schlissel also fails to recognize that there are limitations to the amount of tax incentives that can be used by a corporation. Once a corporation has reached the limit on the level of either federal or state tax incentives that can be used, ownership of wind generation facilities becomes much less economic. Otter Tail's future development of wind generation is likely to be a blend of ownership and PPA's as the situation and the Company's ability to use the tax incentives dictate.

Q: Why did you limit the amount of wind that the model could select in doing your resource planning?

A: We selected a limit of 160 MW of new wind. The reason we did that is because there are transmission constraints to the amount of wholesale market energy that can be imported to the Otter Tail system. The electricity needs to come from some other source when the wind is not blowing. Prior IRP-Manager planning runs had indicated that the model would not pick wind and install combustion turbines to back up the wind. That combination was too

expensive. The planning model will select more wind only if we allow unlimited capability to purchase energy from the spot market to back up the wind generation, and do not have any associated transmission costs. Some of the interfaces that Otter Tail would need to use to import energy to the system are significantly constrained, and far outside the Otter Tail system. This is an issue that was discussed with the Midwest Independent Transmission System Operator (MISO), who indicated that studies do not exist to determine the maximum import capability to the Otter Tail system. MISO also indicated that this is a situation that other utilities had noted as well. As a result of these discussions the IRP-Manager model was limited in its ability to import energy to a level that was little below the Otter Tail system annual peak demand. For Otter Tail to allow the model to implement unrestricted amounts of wind generation, without considering additional major transmission costs and without considering the transmission limitations or the reliability constraints, would be imprudent.

Q: Is it reasonable to assume a commercial operational date of mid-2012?

A: Mr. Schlissel suggests that since costs are likely to increase as time passes, Otter Tail should remodel using new cost estimates based on a commercial operation date of sometime in the year 2013. Of course, at any given moment in time, a new modeling run could be conducted using the latest information on any of the assumptions that must be made. Right now, we are confident that the Big Stone Unit II facility can be brought online by mid-2012 and there is no need to remodel using a new operational date with revised and increased cost estimates. Also, any delay in operation of new generation resources will increase the costs regardless of the type of facility constructed.

Q: Do you include a capacity factor when doing resource planning?

A: No. An integrated resource planning model does not use a capacity factor. The generating unit information is entered into the model, and the model determines how much it needs to use the facility, taking into consideration all of the costs and operating parameters of all of the resources simultaneously. The actual capacity factor of a resource will typically vary from year to year as maintenance schedules, load changes, and cost changes dictate.

III. MANITOBA HYDRO ALTERNATIVE

Q: Mr. Schlissel suggests at pages 60-61 of his testimony that an alternative plan – the purchase of hydro power – is essentially the same cost as constructing the Big Stone Unit II facility? What is your response to that claim?

A: Mr. Schlissel only compares the respective revenue requirements of the Manitoba Hydro and Big Stone Unit II options through the year 2020. His use of the revenue requirements only through the year 2020 violates one of the most basic tenets of resource planning, known as "end effects." Normally, a resource plan is developed over a period of 15 years. However, the lives of almost all facilities are longer than 15 years. Stopping the analysis at the end of the planning period creates a significant bias against capital-intensive projects.

To prevent this bias, resource planners must use a process to capture these "end effects" as they are known. With IRP-Manager, this is accomplished by halting any load growth at the end of the planning period, and allowing the model to evaluate the costs for a sufficient period beyond the end of the planning period. This allows the model to evaluate costs over a much longer period, but not continue to add resources to meet load growth which would complicate evaluation of the near term results. The exact time period to be used is a

balance that the resource planner must evaluate: establishing a balance between ensuring that the end effects period is long enough to sufficiently capture the effects and the additional computer running time impacts from increasing the evaluation period. The Strategist model, too, has a couple of different methods readily built into the model to ensure that end effects are considered.

Mr. Schlissel's choice of only including the data through 2020 ignores significant cost differentials between the cost of the Big Stone Plant II project and the Manitoba Hydro proposal in the planning period beyond 2020. These cost differentials beyond 2020 move the analysis in favor of the Big Stone Plant II project. Mr. Schlissel has distorted the analysis results by selective exclusion of the post-2020 data. Considering data only through 2020 is equivalent to deciding which vehicle to purchase based on 2 ½ years of cost data, even though you plan to keep it for 10 years.

Q: Does this conclude your rebuttal testimony?

A: Yes.