STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

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Otter Tail Corporation **Advance Determination of Prudence Application**	**Case No. PU-06-481**
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. **Advance Determination of Prudence Application**	**Case No. PU-06-482**

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Mike Diller deposes and says that:

He is over the age of 18 years and not a party to this action and, on the **9th day of April, 2008,** he sent by electronic mail and/or deposited in the United States Mail, Bismarck, North Dakota, 7 envelopes by first class mail, fully prepaid, securely sealed, a copy of:

1. **Supplemental Direct Testimony of Terry Deason**
2. **Affidavit of Mailing**

The envelopes were addressed as follows:

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Each address shown is the respective addressee's last reasonably ascertainable post office address.

Mike Diller

Subscribed and sworn to before me
this **9th day of April, 2008**.

Charlene A Magstadt
Notary Public

SEAL

CHARLENE A MAGSTADT
Notary Public
State of North Dakota
My Commission Expires Jan 7, 2010

Public Service Commission
State of North Dakota

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April 9, 2008

Illona Jeffcoat-Sacco
Executive Director
North Dakota Public Service Commission
600 E. Boulevard Ave. Dept 408
Bismarck, ND 58505-0480

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:

Enclosed for filing please find the original and seven copies of the following documents:

1. Supplemental Direct Testimony of Terry Deason
2. Affidavit of Mailing.

Sincerely,

William W. Binek
Chief Counsel

Enclosures

cc: Service List

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NORTH DAKOTA

In the Matter of the Application of Otter Tail Corporation, d/b/a Otter Tail Power Company, for an Advance Determination of Prudence For the Big Stone II Generating Plant	)))))	Case No. PU-06-481
In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., For an Advance Determination of Prudence of Montana-Dakota's Participation & Ownership Interest in the Big Stone II Generating Station	)))))))	Case No. PU-06-482

SUPPLEMENTAL
DIRECT TESTIMONY

OF

TERRY DEASON

Special Consultant

Radey Thomas Yon & Clark

April 8, 2008

SUPPLEMENTAL DIRECT TESTIMONY OF TERRY DEASON

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL DIRECT TESTIMONY OF TERRY DEASON

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Terry Deason. My business address is 301 South Bronough St., Suite 200, Tallahassee, Florida 32301.

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

A: I am employed by the firm Radey Thomas Yon and Clark as a Special Consultant specializing in energy, telecommunications, water and wastewater and public utilities.

Q: Did you previously submit testimony in this proceeding?

A: Yes. I submitted testimony on behalf of the advocacy staff of the North Dakota Public Service Commission, along with 14 exhibits, on May 31, 2007.

II. PURPOSE AND BACKGROUND

Q: What is the purpose of your supplemental testimony?

A: The purpose of my supplemental testimony is to present the results of my review of the modified applications, from Otter Tail Power Company (Otter Tail) and Montana-Dakota Utilities Company (MDU) (the applicants), for advance determination of prudence for the Big Stone II Generating Station.

Q: What necessitated the modifications to the original applications?

A: The modifications were made as a result of two participants, Great River Energy and Southern Minnesota Municipal Power Agency, withdrawing from the project. These withdrawals, along with a delay in the certificate of need case in Minnesota, affected both the size and the timing of Big Stone II.

Q: Based upon your review, what is your understanding of the current proposal regarding Big Stone II?

A: The applicants have determined that a down-sized version of Big Stone II, either 500 MWs or 580MWs, is the most cost-effective alternative available to meet their needs for baseload generation in 2013. The applicants' supplemental case describes their reasons, along with updated analyses, for this determination.

Q: What were the design and operating characteristics of Big Stone II as originally proposed?

A: Big Stone II was originally proposed to be a 630 MW supercritical pulverized coal unit using state of the art technologies for both its thermal generation and its pollution control systems. It was proposed to be constructed at the existing site of Big Stone I and share common facilities at that location. It was to burn Powder River Basin (PRB) coal that was to be delivered by the Burlington Northern Santa Fe Railway Company (BNSF). It was to be interconnected using existing transmission corridors with increased transmission infrastructure to meet Midwest Independent System Operator (MISO) requirements. Big Stone II was to be jointly owned by seven participants with Otter Tail and MDU each owning 19.3%, or approximately 120 MWs each.

Q: Have any of these design and operating characteristics changed?

A: The size of Big Stone II, along with the number of participants and their respective ownership interests, has now changed. Otter Tail is now proposing an ownership interest in the range of 120 MWs to 133 MWs. MDU is now proposing an ownership interest of 133 MWs. The other major design and operating characteristics of Big Stone II essentially remain unchanged, i.e. the technology, location, fuel source and interconnection requirements remain the same.

Q: What were your earlier recommendations for Big Stone II as originally proposed?

A: I earlier reviewed Otter Tail's and MDU's need for additional baseload generation, the Power Plant Site Evaluation Study and the applicants' cost studies for Big Stone II and other generation alternatives. Within the cost studies, I reviewed numerous inputs and assumptions and classified them within six categories: Wind Inputs; Construction Inputs; Operating Inputs; Fuel Inputs; Financial Inputs; and Other Assumptions. I also reviewed Big Stone II's interconnection requirements and its coal delivery and management systems. Within my overall review, I also identified risk factors and strategic considerations for various generation alternatives. I concluded that Big Stone II, as originally proposed, should be approved subject to further clarifications of potential ambiguities within the cost studies and subject to five conditions. The five conditions addressed reporting requirements and coal delivery and inventory management.

III. REVIEW OF INPUTS

Q: Did you once again review the inputs and assumptions used by the applicants for Big Stone II and other generation alternatives?

A: Yes, I did. In addition to the applicants' prefiled supplemental testimony, I reviewed the applicants' responses to 62 data requests submitted to them on March 20 and March 24, 2008. I will discuss relevant inputs and assumptions according to the six categories that I used in my initial review.

Q: What did your review reveal concerning wind inputs?

A: The Burns & McDonnell study, sponsored by Otter Tail, modeled wind as a purchased resource with availability sufficient to displace the equivalent of a 40% capacity factor of a combined cycle gas turbine plant (CCGT). The study continued to use a \$40/MWh cost for wind with the federal production tax credit (PTC) in place. Without the PTC, it was assumed that the cost of wind would be \$20/MWh higher. The study also used a 5.0% annual escalation rate. No transmission costs for wind were included.

MDU's expansion plan sponsored by Mr. Heidell did not model wind purchases, but rather assumed a capital cost of wind of \$2,000/kW. This is a 67% increase over the assumed capital cost of wind in the previous study. Mr. Heidell used two different capacity factors for wind, 52% in scenarios I and II, and 38% in Scenarios III and IV. He also assumed two different PTC expiration dates, January 1, 2013, for Scenarios I and II, and January 1, 2009, for Scenarios III and IV. Like the Burns & McDonnell study, Mr. Heidell did not include the cost of transmission system upgrades for wind resources.

Q: What did your review reveal concerning construction inputs?

A: Otter Tail's assumed cost of a down-sized Big Stone II was based upon its earlier estimate of a 630 MW plant. This cost was scaled down using factors from the Electric Power Research Institute (EPRI) and escalated for the delayed in-service date to result in assumed costs of \$1.272 billion (\$2,545/kW) for a 500 MW unit and \$1.411 billion

(2,434/kW) for a 580 MW unit. The assumed cost of a 500 MW CCGT plant remained the same as the earlier study at $674/kW. These costs do not include transmission costs nor an allowance for funds used during construction (AFUDC). The escalation rate used for a supercritical coal unit was 6%, and for a CCGT it was 5%.

Mr. Heidell used the same construction costs for the down-sized Big Stone II, but included transmission line costs and interest during construction (AFUDC). For a 120 MW CCGT unit, Mr. Heidell assumed a cost of $1,795/kW.

Q: What did your review reveal concerning operating inputs?

A: My review did not reveal any significant changes for operating inputs, other than some increase in the operating and maintenance costs per MWh.

Q: What did your review reveal concerning fuel inputs?

A: Otter Tail used a similar cost of PRB coal as it did in its earlier study, $1.74/MMBtu now versus $1.71/MMBtu earlier. However, Otter Tail increased the escalation rate from 2.9% to 3.5%. For natural gas, Otter Tail increased the cost from $7.60/MMBtu in 2011 to $8.31/MMBtu in 2012 and kept the same escalation rate of 3.0%. Within this cost is an assumed transportation cost of $0.40 MMBtu. The commodity price of the gas is based upon the October 2007 New York Mercantile Exchange (NYMEX) futures price for Henry Hub natural gas supply in 2012.

MDU also increased its assumed cost of coal, but no explanation was given by Mr. Heidell. A comparison of MDU's original and updated coal cost assumptions is shown in Exhibit No.___(JTD-15). A comparison of Otter Tail's assumed cost of coal to that of MDU is shown in Exhibit No.___(JTD-16).

MDU's updated cost of natural gas is now based on the long-term Department of Energy (DOE) Energy Information Administration (EIA) natural gas forecast, as adjusted by MDU's in-house experience. MDU's earlier forecast of natural gas was based on PA Consulting's consensus natural gas forecast. No reason was provided for this change in methodology. A comparison of MDU's original and updated forecasts of the commodity price of natural gas is shown in Exhibit No.___(JTD-17). A comparison of Otter Tail's forecasted commodity cost of natural gas to that of MDU is shown in Exhibit No.___(JTD-18).

MDU, like Otter Tail, also added a transportation cost to its commodity price of natural gas to result in a delivered cost of natural gas. For Scenarios I and II, MDU used a transportation cost based on the South Dakota Intrastate Pipeline Company (SDIP) tariff. For Scenarios III and IV, MDU used a lower transportation cost to determine whether a hypothetical reduction in gas transportation costs makes natural gas fired generation more attractive. However, MDU's assumed transportation component for all scenarios is much higher than the $0.40 MMBtu assumed by Otter Tail. A comparison of MDU's assumed cost of delivered natural gas to that of Otter Tail is shown in Exhibit No. ___ (JTD-19) for MDU's Scenarios I and II and No. ___ (JTD-20) for Scenarios III and IV.

Q: What did your review reveal concerning Financial Inputs?

A: My review did not reveal any significant changes in Otter Tail's financial inputs. Mr. Heidell indicated that he updated the cost-of-capital assumptions used for Scenarios

III and IV. In response to Data Request No. 61, he clarified that he reduced the cost of capital to 7.61%.

Q: Did your review reveal any other notable inputs, assumptions or considerations?

A: Yes, there are two. First is the recognition of potential off-system power sales from Big Stone II. I discussed off-system sales (asset-backed sales) in my previous testimony and identified it as an item needing additional clarification. At that time, the applicants provided the requested clarifications in their rebuttal case. In their updated case, MDU has now included off-system sales (in Scenario IV) and has quantified the estimated benefit at $72 million on a net present value (NPV) basis. In response to Data Request No. 39, MDU explained the methodology used to make this estimate. Mr. Heidell concludes that the potential for off-system sales is a benefit for proceeding with Big Stone II, but that Big Stone II is not dependent on off-system sales to make it the choice of their expansion plan.

The second consideration is transmission requirements. The physical transmission requirements for Big Stone II remain essentially the same, regardless of whether Big Stone II is sized at 500 MWs or 630MWs. The cost of the required transmission has been updated from $238 million to $249 million. Due to this increase and the downsizing of Big Stone II, the per kW cost of transmission increases by $120, from $378 to $498 (at 500 MW size).

IV. FINDINGS AND CLARIFICATIONS

Q: What are your findings for Big Stone II as currently proposed?

A: Based upon my review and subject to a number of additional clarifications, Big Stone II has been shown by the applicants to be a cost-effective alternative to meet their baseload generation needs. However, the case for Big Stone II is not as compelling as when it was originally proposed and its risk factors have increased.

Q: Why do you conclude that Big Stone II is a cost-effective alternative to meet the applicants' baseload generation needs?

A: First, let me reemphasize that there are areas which I believe need further clarification from the applicants. If these clarifications are provided and they sufficiently address the areas of concern, then I would conclude that Big Stone II is a cost-effective alternative. This conclusion is based upon my review of the costs and operating characteristics of Big Stone II and those of other baseload alternatives, as presented by the applicants in their supplemental case.

The applicants' supplemental case essentially uses the same approaches used earlier to justify Big Stone II as a 630 MW unit. The downsized version of Big Stone II is essentially the same as the earlier version, only smaller. It would utilize the same supercritical technology, which has proven to be efficient and reliable. It would continue to operate with low heat rates, high availability factors, and low emissions rates. It would continue to be owned by a group of utilities to achieve economies of scale that none of the individual utilities could accomplish on their own. It would continue to be located at an existing site and have the ability to cost-effectively share common facilities. It would continue to be a dispatchable resource and enhance the possibility of additional off-system sales for the benefit of the applicants' ratepayers. And it would enhance the reliability of the transmission grid and potentially increase export capabilities out of North Dakota.

Q: What are the clarifications that are needed before it can be concluded that Big Stone II is a cost-effective alternative to meet the applicants' baseload generation needs?

A: First, let me state the obvious. The time to review the revised case and file supplemental testimony has been short. This is not a criticism. I understand the need for this case to be expedited so that the applicants' need for baseload generation may be timely addressed. However, the short time frame has allowed only one round of data requests to be submitted. Therefore, ambiguities or potential inconsistencies, which possibly could have been adequately addressed during a longer data collection process, must now be identified in testimony. I invite the applicants to provide the needed clarifications in their rebuttal testimony so that I and the advocacy staff can review them prior to hearing.

The areas needing additional clarification can be summarized as follows:

- Wind PTC and fixed costs;
- Capital costs;
- Fuel forecasts and escalations;
- Project financing; and
- Environmental compliance costs.

Q: What are the variables affecting wind generation?

A: The viability of wind generation as a component of a baseload generation expansion plan is dependent on many variables. Two of the most significant are PTC assumptions and capacity factors. MDU addresses these variables in its response to Data Request No. 45. Another consideration is fixed operating costs, which MDU addresses in its response to Data Request No. 62.

Q: Why is the PTC an important consideration?

A: The PTC can substantially reduce the cost of wind generation. Otter Tail assumes that the levelized cost of purchased power is reduced by a third with the PTC, from a cost of $60/MWh without the PTC to a cost of $40/MWh with the PTC. Otter Tail goes on to calculate a levelized busbar cost of wind plus CCGT, both with and without the PTC. With the PTC, the wind plus CCGT alternative is only 2.6% higher than the cost of Big Stone II, $88.55 per MWh for wind plus CCGT compared to $86.27 per MWh for Big Stone II. Without the PTC, the differential is $11.37 per MWh or 13.2%. The significance of the PTC is apparent.

Q: What needs to be clarified in Otter Tail's approach?

A: What is unclear within Otter Tail's approach is the timing of the impact on costs of assuming a discontinuation of the PTC. It is unclear when the discontinuation is assumed to be effective. It is also unclear whether the cost to purchase wind would increase by $20 per MWh immediately or gradually increase over time. I believe Otter Tail should identify the timing of its assumption, why the timing assumed is appropriate and how it impacts the determination of the levelized busbar costs.

Q: Does MDU's approach differ from Otter Tail's?

A: Yes, instead of modeling wind as purchases, MDU modeled wind as a capital project, at an assumed cost of $2,000 per kW in 2006 dollars. This is an $800/kW increase over the value used by Mr. Heidell in his previous testimony and is further addressed in MDU's response to Data Request No. 58.

All of Mr. Heidell's expansion plan scenarios assume discontinuation of the PTC, effective either January 1, 2009 (Scenarios III and IV) or January 1, 2013 (Scenarios I and II). Big Stone II is chosen as part of the expansion plan in all scenarios. However, according to Mr. Heidell's results, extending the PTC by four years (along with an assumed higher wind capacity factor) materially impacts the NPV margin by which Big Stone II is the preferred alternative. Under Scenarios I and II, the NPV margin by which Big Stone II is the preferred alternative is within a range of $12 million to $33 million or only 0.6% to 1.5% of the NPV of the next best expansion plan without Big Stone II. Thus, the PTC (and the assumed wind capacity factor) can have a material impact on the relative cost-effectiveness of a wind alternative.

Q: What needs to be clarified within MDU's approach?

A: What is unclear is if an assumed continuation of the PTC beyond four years would result in a lesser or no amount of Big Stone II being chosen as part of the expansion plan. Mr. Heidell states that an extension of the PTC is likely but that a permanent extension remains uncertain. I believe MDU should clarify if an extension longer than four years would change the generation expansion plan and why such an extension should or should not be considered. MDU should also address whether the resulting wind generation would cause operational and reliability problems for MDU's system. Another area needing clarification is the assumptions shown in Mr. Heidell's Table 4. The assumed capital, fixed and variable costs for wind remain the same regardless of whether the PTC is ~~present or not~~. I believe MDU should explain why the existence of non-existence of the PTC has no impact on these assumed costs.

Q: In your previous answer, you identified wind capacity factor as an important determinant. Did you review the assumed wind capacity factors used by the applicants?

A: Yes, I did and I also submitted a number of data requests concerning wind capacity factors and cost assumptions.

Mr. Heidell conservatively assumed a wind capacity factor of 52% in Scenarios I and II. In Scenarios III and IV, he reduced it to 38%, just below Otter Tail's assumed 40% capacity factor. The reasons for these capacity factors and overall wind costs are explained in testimony. And in the confidential response to Data Request Nos. 28 and 29, these assumptions are further explained and compared to actual wind projects. My review concludes that the information submitted is sufficient without the need for further clarification.

Q: What clarifications are needed for capital costs?

A: The applicants "scaled down" the original cost estimate of a 630 MW unit to result in the updated capital costs for a 500 MW unit and a 580 MW unit. To be conservative, the applicants used the same construction time frame of 62 months from the time of final permits and continued to use the higher contingency factor of 13.5%.

The use of the EPRI scaling factors and how Big Stone II compares to other supercritical units is more fully addressed in the responses to Data Request Nos. 23, 24 and 25. These responses confirm that the scaling is a linear function. What is unclear is whether the scaling adequately factors the proportional higher costs of a smaller unit. For example, when Big Stone II was designed to be a 630 MW unit, it was represented to be the most cost-effective size and incorporated the best matching of components to achieve its higher efficiencies and cost-effectiveness. With that level of costs being the starting point, it is possible that there is some residual of this optimal sizing such that the scaled-down costs are not truly representative of actual construction costs of a smaller unit and its reconfiguration of smaller sized components. The comparison of Big Stone II to a "scaled-down" version of Duke Energy's 800 MW Cliffside unit (response to Data Request No. 25) indicates that the costs of Big Stone II are not artificially understated. The cost comparisons to other supercritical units shown in the response to Data Request No. 24 also support this conclusion. Nevertheless, I believe the applicants should clarify how the scaling factors do not result in understated cost estimates and how the scaled-down costs of Big Stone II match the configuration of components to be utilized.

Q: Are there any other capital cost items which need clarification?

A: Yes, there are two and they both arise from differences in assumptions and approaches used by the applicants.

Otter Tail's Updated Economic Evaluation assumes the cost of a 500 MW CCGT plant to be $674/kW, while Mr. Heidell assumes a $1,795/kW cost for a 120 MW combined cycle plant. This is a large disparity. It could be explained by the difference in the size of the two assumed units. If the disparity in costs is explained by the size of the units, Mr. Heidell should explain why he did not use a larger combined cycle unit for comparison purposes. If the disparity is not explained by the difference in size, Mr. Heidell should explain why his higher assumed cost is appropriate.

The other difference is in the approach used for AFUDC. Otter Tail's busbar costs do not include AFUDC, while Mr. Heidell included AFUDC in his scenarios. Since Big Stone II is a high capital cost alternative, including AFUDC would be the more conservative approach. In its confidential responses to Data Request Nos. 21 and 22, Otter Tail quantifies the impact of AFUDC on the per kW cost of Big Stone II. I believe Otter Tail should explain why AFUDC was excluded and determine the materiality of its exclusion on the revised busbar costs.

Q: Are any clarifications needed for coal forecasts and escalations?

A: Based upon my review and the applicants' responses to data requests, I have identified no coal cost assumptions which need further clarification. Both Otter Tail and MDU increased their projected cost of coal from their earlier estimates. Otter Tail also increased its assumed escalation rate from 2.9% to 3.5%, which I believe is a conservative assumption. The conservative nature of this assumption is further supported by the confidential response to Data Request No. 14. MDU's coal cost forecast appears to use an annual escalation factor of approximately 3.0%. The resulting cost forecasts for coal by MDU and Otter Tail are very similar. There are essentially no differences in the early years with only slight differences in the later years, probably due to the different escalation rates. Refer to Exhibit No. ___ (JTD-16) for a side-by-side comparison.

Q: How did the applicants forecast the price of natural gas?

A: Otter Tail and MDU each used different approaches with both resulting in increased forecasted natural gas costs. Otter Tail used the NYMEX futures prices for gas supply in 2012 with a 3% escalation rate. Otter Tail's approach is more fully explained in its response to Data Request No. 33. MDU's forecast is based upon the high scenario cost from EIA, as adjusted by MDU's in-house experience. MDU's approach is more fully explained in its response to Data Request No. 56. While MDU does not expressly state its assumed escalation rate, it appears to be approximately 4%.

A comparison of Otter Tail's and MDU's forecasted commodity cost of gas is shown in Exhibit No. ___ (JTD-18). This comparison shows their forecasts for the commodity cost of gas to be quite similar, with Otter Tail's forecast being higher in the early years and MDU's forecast being higher in the later years. Only in the later years, does the difference grow to more than $0.40 MMBtu, probably because of MDU's higher escalation rate.

Q: Are these differences significant?

A: I do not consider these differences to be material for long-term planning purposes. Predicting future prices of natural gas is inherently uncertain, particularly over a long-term horizon which is necessary in evaluating alternative generation technologies. There are many uncontrollable drivers that influence the price of natural gas: expected worldwide economic growth and worldwide demand; North American natural gas demand and production; the worldwide supply and demand for Liquefied Natural Gas; the geopolitics of many regions of the world; and the potential for new environmental requirements, particularly carbon dioxide regulation.

Q: Did the applicants' gas forecasts factor in potential impacts from carbon dioxide regulations?

A: No, they did not. This question was posed to the applicants and they confirmed that their forecasts did not explicitly consider the potential impacts of carbon dioxide regulations. It is unclear, however, whether MDU's assumed escalation rate was influenced by potential carbon dioxide regulations.

Q: What effect would carbon dioxide regulations have on natural gas?

A: While there is speculation as to the degree such regulations would affect natural gas prices, they would certainly cause greater demand to be placed on existing natural gas supplies, at least in the short run. This would certainly place upward pressure on prices. In fact, I believe this is already being manifested to some degree by the number of coal units which have been cancelled and partially replaced by additional gas-fired generation. To the extent the applicants' gas forecasts do not consider the impact of potential carbon dioxide regulations, they may very well be conservative.

Q: Are there differences in the applicants' assumed transportation cost for natural gas?

A: Yes, and in two of the scenarios the difference is quite large. Otter Tail used a conservative transportation cost of $0.40/MMBtu. For Scenarios I and II, MDU used a transportation cost based on the SDIP tariff, which is forecasted to be as high as $3.99/MMBtu. To test the sensitivity of using a lower cost of delivered natural gas, MDU reduced the transportation component in Scenarios III and IV to a range of $0.65/MMBtu to $1.14/MMBtu. In response to Data Request No. 31, MDU provides historical transportation costs incurred for its combustion turbine units, which average $1.17/MMBtu.

Q: How does MDU's assumed cost of delivered natural gas compare to Otter Tail's?

A: These comparisons are shown in Exhibit Nos. ___ and ___ (JTD-19 and JTD-20). Even in JTD-20, which uses MDU's lower transportation costs, MDU's assumed cost of delivered natural gas is equal to or higher than Otter Tail's assumed cost in every year.

Q: Are these differences significant?

A: In the early years, the differences are not material. However, in the later years the differences are larger and only escalate. I do not know whether they are significant enough to affect MDU's conclusion that Big Stone II is the most cost-effective baseload alternative. Given the difficulties and uncertainties in making long term forecasts of a volatile commodity like natural gas, MDU's forecast is probably as valid as Otter Tail's. However, I believe MDU should provide an additional sensitivity analysis at Otter Tail's assumed gas costs or explain why Otter Tail's assumptions would not apply to MDU's use of gas-fired generation alternatives.

Q: How would the applicants finance the construction of Big Stone II?

A: Neither of the applicants has secured financing at this early stage. The actual financing used would depend upon the capital markets and the companies' financial position at the time a decision is made to go forward with Big Stone II (or any other alternative generation project). However, the applicants have made assumptions concerning the financing in their cost studies and expansion models.

Q: What are those assumptions?

A: Otter Tail's financing assumptions have not changed. Otter Tail assumes a 50%/50% debt/equity ratio with a 7.5% cost of debt and a 12% return on equity. This results in an overall cost of capital of 9.75%. Otter Tail also assumes an effective tax rate of 40%.

MDU has updated its cost of capital to 7.61%. MDU also assumes a 50%/50% debt/equity ratio. However, MDU assumes an 11% cost of equity and a 6.5% cost of debt, with a downward adjust to recognize the tax deduction of interest on the debt. The assumed tax rate is 35%.

Q: Why is MDU's cost of capital lower than Otter Tail's?

A: MDU's assumed cost of capital is 214 basis points lower than Otter Tail's. MDU's lower cost of equity accounts for 50 basis points and the lower cost of debt accounts for another 50 points of the difference. The remaining 114 points are due to the adjustment for the interest tax deduction (6.5% x .50 x .35 = 1.14% or 114 points).

Q: Is MDU's approach correct?

A: It is true that the interest on debt is tax deductible and effectively lowers the after-tax cost of debt. However, the return earned on equity capital is taxable and effectively raises the after-tax cost of equity. The correctness of MDU's approach would depend on the structure of MDU's expansion model and how it accounts for the income taxes on equity capital and the income tax deduction for interest expense. I believe that MDU should explain how its expansion model accounts for income taxes and confirm to the Commission that the true (after-tax) cost of equity capital is recognized when comparing alternative generation expansion plans.

Q: Are MDU's 11% return on equity and its 6.5% cost of debt appropriate?

A: I cannot conclude that they are inappropriate. However, Otter Tail's assumptions are more conservative and provide a greater assurance that a capital-intensive generating unit, such as Big Stone II, is truly the more cost-effective alternative. This is particularly true given the greater scrutiny capital markets are giving to projects with higher carbon dioxide emission profiles. In response to Data Request No. 13, MDU acknowledges that this greater level of scrutiny could place upward pressure on the cost of debt and equity, but concludes that its assumed cost of capital is still reasonable. Nevertheless, I believe MDU should confirm to the Commission that the results of its expansion plan remain the same, even with an assumed higher cost of capital, or in the alternative provide greater assurance that its assumed capital costs are appropriate in today's capital markets.

Q: You referenced a greater degree of scrutiny that capital markets are giving to projects with higher carbon dioxide emission profiles. Can you further explain this?

A: Yes. An article entitled "Banks to Consider Environmental Impact" appeared in the February 4, 2008 issue of the Wall Street Journal. This article was the basis for a series of questions posed to the applicants within Data Request No. 13. In response to this Data Request, Otter Tail provided more information on "The Carbon Principles" adopted by Citi, JPMorgan Chase and Morgan Stanley. The signatory banks agreed to follow an Enhanced Diligence process for high carbon dioxide emitting technologies. Within "The Carbon Principles" is the following statement:

> *Due to evolving climate policy, investing in CO_2-emitting fossil fuel generation entails uncertain financial, regulatory and certain*

environmental liability risks. It is the purpose of the Enhanced Diligence process to assess and reflect these risks in the financing considerations for certain fossil fuel generation.

Q: Does this mean that financing will be unavailable for projects such as Big Stone II?

A: No, not at all. It means that such projects will receive greater scrutiny "in a process aimed at providing banks and their power industry clients with a consistent roadmap for reducing the regulatory and financial risks associated with greenhouse gas emissions." There is explicit recognition that investment will be needed in conventional or advanced generating facilities, which may include natural gas, coal and nuclear technologies.

Q: Will the greater scrutiny result in a higher cost of capital for projects with a higher carbon dioxide emissions profile?

A: This may be possible. However, I believe it will depend on what the higher level of scrutiny reveals. If it reveals a process whereby all alternatives, including energy efficiency and low-carbon technologies, are fairly considered and their relative carbon risks are considered and mitigated, then the impact on capital costs should be minimized.

Q: How can the risks be mitigated?

A: Until such time as the rules for carbon reduction are adopted and their impacts quantified and understood, both utilities and their customers are exposed to greater risks. This is particularly true for utilities which are faced with the need to add capacity at this time of uncertainty. A major way to mitigate the risk is to engage in a thorough open process to fairly evaluate all alternatives and their relative risks, such as what this

Commission is currently undertaking. And after the process is complete, a degree a regulatory certainty should provide needed assurances to the capital markets.

Q: Do potential carbon dioxide regulations have ramifications beyond financing risks?

A: Yes, they could have a material impact on the cost-effectiveness of a relatively high carbon emitting unit, such as Big Stone II, compared to one with a lesser carbon profile, such as wind or CCGT.

Q: Do you believe the costs to mitigate carbon dioxide emissions to be an environmental externality?

A: I have no opinion as to the legal definition of an environmental externality. From an economic and regulatory perspective, carbon dioxide costs continue to be externalized in many jurisdictions. However, in many other jurisdictions, they have been or are currently in the process of being internalized. And even though there is not a national policy or program in place requiring reductions in carbon dioxide emissions, most believe one is imminent. Its imminence is evident by concerns expressed by the investment community and decisions in many jurisdictions to cancel or defer proposed coal units. Otter Tail's expert in coal prices, L.E. Peabody & Associates, also believes that some form of carbon dioxide regulation will be enacted in the 2010 to 2015 time period (Response to Data Request No. 15).

Q: Do you believe it would be appropriate for this Commission to consider the impacts of potential carbon dioxide regulations?

A: Again, I express no opinion on the Commission's legal authority to do so. However, from a regulatory policy perspective, carbon dioxide costs should be considered for at least two reasons.

First, the choice of the appropriate type of generation to add will have significant cost considerations for decades to come. This is particularly true for a capital-intensive option such as Big Stone II. The decision to make such a large long-term investment should be made with the best information available. This should include even the speculative and as of yet unquantified costs of carbon dioxide emission reductions.

Second, as discussed previously, the possibility of carbon dioxide regulations has resulted in actions by the investment community. Therefore, at least for the financing aspects, one could argue that carbon dioxide costs are being internalized based upon their perceived risks. To help mitigate these risks, regulation should openly consider their impacts and demonstrate that any generation or efficiency alternative pursued is the most cost-effective when all costs are considered. This should provide a degree of regulatory certainty which should facilitate acquisition of the needed financing under the best terms available.

Q: What form will potential carbon dioxide regulations take?

A: Unfortunately, this question does not have a definitive answer at this time. There is much speculation that the regulations will be based upon a cap and trade system. Even if a cap and trade system is ultimately implemented, there would be questions concerning the level and timing of the caps, the amount of free allowances and how they would be distributed, whether domestic and international offsets would be allowed, and whether there would be a safety value mechanism should the cost of allowances rise too high.

Q: Have the applicants considered the impacts of potential carbon dioxide regulations?

A: As stated in Mr. Uggerud's testimony, the applicants did not explicitly include the costs (or a risk value) for carbon dioxide regulation. However, he did reference an assumed $9/ton carbon dioxide tax used in their Minnesota Certificate of Need proceeding. This $9/ton tax was applied to all tons of carbon dioxide emitted even though there may be free allowances permitted in pending legislation. Inclusion of the $9/ton carbon dioxide tax did not change the results of Otter Tail's Updated Economic Evaluation of Baseload Generation Alternatives.

Q: Does this updated evaluation address carbon dioxide costs?

A: Yes, in a limited fashion. This study, sponsored by Mr. Greig, quantifies the break-even carbon dioxide cost values at which Big Stone II's busbar cost would be equal to the busbar cost of the CCGT plus wind alternative.

Q: What are these break-even values?

A: For the 500 MW Big Stone II, the break-even is $12.10/ton with continuation of the PTC. Without the PTC, the value is $24.40/ton. For the 580 MW Big Stone II, the break-even values would be approximately $3/ton higher. It is my understanding that these values do not consider any free allowances that may be available under a cap and trade approach.

Q: Which of these break-even values is more relevant?

A: I believe they are all relevant for the purposes that they were calculated. However, the break-even values assuming discontinuation of the PTC may be more relevant when considering the long-term cost-effectiveness of competing generation technologies.

Q: Why do you believe the break-even values without the PTC may be more relevant in the long-term?

A: The PTC was established in the Energy Policy Act of 1992 as an incentive, beyond those already available within the market, to promote the production of renewable energy. It has been successful even though it has been allowed to periodically lapse by Congress and has never been extended for more than two years at a time. If carbon dioxide regulations are put in place with a cap and trade scheme, it could be argued that there would be enough incentive within the ensuing market for wind energy without the need for a PTC. Of course, predicting what Congress may or may not do is tenuous.

Q: In your earlier testimony you stated that the price of natural gas can be the single most important factor in justifying the relatively high costs of a solid fuel generating plant like Big Stone II. Is this still your testimony?

A: Yes, it is. In fact, the potential impacts of future carbon dioxide regulations can be expressed in terms of a break-even cost of natural gas. This is done through a dispatch cost comparison at various assumed costs of carbon dioxide emission allowances.

This was the subject of Data Request No. 11. As Otter Tail's response indicates, Big Stone II would continue to be the first or one of the first units dispatched over a broad range of assumed carbon dioxide emissions costs. The break-even point for natural gas varies from a low of $2.18 for the case with no carbon dioxide emissions costs to a high of $6.37 for the case with $30/ton carbon dioxide costs with no free allowances. In other words, before Big Stone II's dispatch order would be jeopardized, the cost of natural gas would have to fall to $6.37/MMBtu at the higher end of the assumed carbon dioxide emissions costs. The $6.37/MMBtu compares to the applicants' projected cost of natural gas of $8.96/MMBtu. And the applicants' projected costs of natural gas do not consider the impacts of carbon dioxide regulations. If they were considered, the projected cost of natural gas would probably be higher.

Q: Are there any needed clarifications for the impacts of potential carbon dioxide regulations?

A: No, the applicants have provided all requested information in this regard and I have not identified the need for any additional clarifications. However, if Big Stone II is approved, I believe there should be a requirement on the applicants to monitor the developments in the carbon dioxide debate and to routinely report them to the Commission. I would also recommend that before construction begins, that the applicants file an updated confirmation as to the cost-effectiveness of Big Stone II in light of the best information then available concerning the anticipated costs of carbon dioxide emission allowances.

Q: Are any other clarifications needed with regard to environmental compliance costs?

A: Yes. On March 14, 2008, the U.S. Court of Appeals for the District of Columbia Circuit granted a motion which requires a maximum achievable control technology standard to be used for emission controls at new power plants, likely requiring at least a 90% mercury removal rate. This was the subject of Data Request No. 35. Otter Tail provided a comprehensive response to the data request. However, it was unclear whether this recent development concerning mercury removal would go beyond what the applicants have already agreed to do in their Settlement Agreement with the Minnesota Department of Commerce and whether there would be any additional costs not already included in Big Stone II's capital and operating costs. Otter Tail should so clarify and identify the impacts of any additional costs, if applicable.

V. SUMMARY AND RECOMMENDATIONS

Q: You have identified a number of areas needing additional clarification. Can you please summarize them?

A: Yes, I will do so by general subject area.

Wind PTC and fixed costs:

- Otter Tail's assumptions concerning the timing of PTC discontinuation;
- The effect (if any) on MDU's expansion plan of a PTC extension beyond four years and any operational or reliability problems resulting therefrom; and
- The effect (if any) of a discontinuance of the PTC on the assumed fixed and variable costs found in Table 4 of Mr. Heidell's supplemental testimony.

Capital costs:

- The effect of EPRI's scaling factors on the cost of Big Stone II as actually configured with smaller components;

- The relative differences in the per kW cost of a CCGT plant assumed by Otter Tail and MDU; and
- The effect on Otter Tail's relative busbar costs by including AFUDC.

<u>Fuel forecasts and escalations</u>:

- The sensitivity on MDU's expansion plan of using Otter Tail's assumed cost of delivered natural gas; or
- An explanation why the use of Otter Tail's assumed cost of delivered natural gas would be inappropriate for MDU's gas-fired generation alternatives.

<u>Project financing</u>:

- An explanation of how MDU's expansion model accounts for the income tax effect of the sources of capital within MDU's assumed cost of capital; and
- The effect on MDU's expansion plan by using a higher cost of capital; or
- An explanation of why MDU's assumed cost of capital is appropriate in today's capital markets.

<u>Environmental compliance costs</u>:

- Identification and explanation of the impacts of any mercury removal costs not already considered within Big Stone II's assumed capital and operating costs.

Q: **In your earlier testimony, you recommended five conditions before granting an advance prudence determination for Big Stone II. Would those conditions continue to apply?**

A: Yes, they would. I would also add the condition that the applicants continue to monitor potential carbon dioxide regulations and that an updated confirmation of Big Stone II's cost-effectiveness be filed prior to the commencement of construction.

Q: Are you recommending an entirely new review before construction were to begin?

A: No, not at all. I am merely recognizing that the applicants have an ongoing obligation to their stockholders and customers to continually monitor any developments in the carbon dioxide debate. My recommendation is to have the applicants report to the Commission on these developments and the impacts they may or may not have on the continuing viability of the Big Stone II project. In fact, this requirement could probably be incorporated within my second condition. This condition requires the filing of budget information and an ongoing obligation to report on any developments which affect the economic viability of the project.

Q: Does this conclude your testimony?

A: Yes, it does.

Exhibit No. ____(JTD-15)

MDU's Assumed Cost of Coal for Big Stone II
$/MMBtu

Year	Original Forecast	Updated Forecast	Percent Change
2010	1.68	1.76	4.76%
2011	1.72	1.81	5.23%
2012	1.76	1.86	5.68%
2013	1.81	1.92	6.08%
2014	1.85	1.98	7.03%
2015	1.90	2.04	7.37%
2016	1.95	2.10	7.69%
2017	1.99	2.16	8.54%
2018	2.04	2.22	8.82%
2019	2.10	2.29	9.05%
2020	2.15	2.36	9.77%
2021	2.20	2.43	10.45%
2022	2.26	2.50	10.62%
2023	2.31	2.58	11.69%
2024	2.37	2.66	12.24%
2025	2.43	2.74	12.76%

Exhibit No.____(JTD-16)

Comparison of Assumed Cost of Coal for Big Stone II
$/MMBtu

Year	MDU Updated Forecast	Otter Tail Updated Forecast	Difference
2010	1.76	1.74	0.02
2011	1.81	1.80	0.01
2012	1.86	1.86	0.00
2013	1.92	1.93	-0.01
2014	1.98	1.99	-0.01
2015	2.04	2.06	-0.02
2016	2.10	2.13	-0.03
2017	2.16	2.21	-0.05
2018	2.22	2.29	-0.07
2019	2.29	2.37	-0.08
2020	2.36	2.45	-0.09
2021	2.43	2.53	-0.10
2022	2.50	2.62	-0.12
2023	2.58	2.72	-0.14
2024	2.66	2.81	-0.15
2025	2.74	2.91	-0.17
Average	**2.21**	**2.28**	**-0.06**

Exhibit No. ____(JTD-17)

MDU's Assumed Commodity Cost of Natural Gas
$/MMBtu

Year	Original Forecast	Updated Forecast	Percent Change
2010	6.78	7.70	13.57%
2011	6.58	7.88	19.76%
2012	6.53	8.00	22.51%
2013	6.77	8.18	20.83%
2014	6.90	8.49	23.04%
2015	6.92	8.80	27.17%
2016	7.10	9.20	29.58%
2017	7.21	9.56	32.59%
2018	7.39	9.94	34.51%
2019	7.77	10.33	32.95%
2020	8.06	10.73	33.13%
2021	8.38	11.15	33.05%
2022	8.69	11.59	33.37%
2023	9.00	12.05	33.89%
2024	9.34	12.52	34.05%
2025	9.70	13.01	34.12%

Exhibit No. __ (JTD-18)

Comparison of Assumed Commodity Cost of Natural Gas
$/MMBtu

Year	MDU Updated Forecast	Otter Tail Updated Forecast	Difference
2010	7.70		
2011	7.88		
2012	8.00	8.31	-0.31
2013	8.18	8.56	-0.38
2014	8.49	8.82	-0.33
2015	8.80	9.08	-0.28
2016	9.20	9.35	-0.15
2017	9.56	9.63	-0.07
2018	9.94	9.92	0.02
2019	10.33	10.22	0.11
2020	10.73	10.53	0.20
2021	11.15	10.84	0.31
2022	11.59	11.17	0.42
2023	12.05	11.50	0.55
2024	12.52	11.85	0.67
2025	13.01	12.20	0.81
Average	**9.95**	**10.14**	**0.11**

Comparison of Assumed Cost of Delivered Natural Gas
$/MMBtu

Year	MDU Updated Forecast*	Otter Tail Updated Forecast	Difference
2010	10.85		
2011	11.12		
2012	11.34	8.71	2.63
2013	11.62	8.96	2.66
2014	12.03	9.22	2.81
2015	12.45	9.48	2.97
2016	12.96	9.75	3.21
2017	13.43	10.03	3.40
2018	13.92	10.32	3.60
2019	11.97	10.62	1.35
2020	12.42	10.93	1.49
2021	12.89	11.24	1.65
2022	13.38	11.57	1.81
2023	13.89	11.90	1.99
2024	14.42	12.25	2.17
2025	14.97	12.60	2.37
Average	**12.73**	**10.54**	**2.44**

* For Scenarios I and II

Exhibit No. ____ (JTD-20)

Comparison of Assumed Cost of Delivered Natural Gas
$/MMBtu

Year	MDU Updated Forecast*	Otter Tail Updated Forecast	Difference
2010	8.41		
2011	8.61		
2012	8.75	8.71	0.04
2013	8.96	8.96	0.00
2014	9.29	9.22	0.07
2015	9.63	9.48	0.15
2016	10.05	9.75	0.30
2017	10.43	10.03	0.40
2018	10.84	10.32	0.52
2019	11.25	10.62	0.63
2020	11.69	10.93	0.76
2021	12.14	11.24	0.90
2022	12.60	11.57	1.03
2023	13.09	11.90	1.19
2024	13.60	12.25	1.35
2025	14.12	12.60	1.52
Average	**10.84**	**10.54**	**0.63**

* For Scenarios III and IV