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

DIRECT TESTIMONY

OF

TERRY DEASON

Special Consultant

Radey Thomas Yon & Clark

May 31, 2007

BEFORE THE NORTH DAKOTA PUBLIC SERVIC COMMISSION

DIRECT TESTIMONY OF TERRY DEASON

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: **What is your educational background?**

A: I received a BS in Accounting, summa cum laude, from Florida State University in 1975, and a Master of Accounting in 1986 from Florida State University.

Q: **What is your employment history?**

A: Other than a year and a half in the banking industry immediately following graduation, my entire professional career has been in the field of public utility regulation. I have held a number of positions in this field ranging from consumer advocate to Commissioner on the Florida Public Service Commission. I most recently finished my fourth term on the Florida Public Service Commission on January 1, 2007. I served in that capacity for a total of 16 years and served as chairman on two separate occasions. A more complete account of my education, work experience and professional associations is contained in Exhibit No. ___ (JTD-1).

Q: **Have you submitted testimony in other utility regulatory proceedings?**

A: Yes, I have. A list of the dockets in which I have previously testified is contained in Exhibit No.___ (JTD-2).

Q: Do you have any relevant experience dealing with siting and prudence determinations for electric generating facilities?

A: Yes, I have. Under Florida Law, any generating facility which utilizes a steam cycle and is greater than 75 MWs must come before the Florida Public Service Commission for a Need Determination. A Need Determination case is quite comprehensive and includes a review of a utility's demand forecasts, its Integrated Resource Plan, its conservation and Demand Side Management (DSM) programs, its overall generating portfolio and whether the proposed generating unit is the most cost-effective alternative available. Over the last 16 years, I have sat on 25 Need Determination Cases involving more than 14,000 MWs of proposed generating capacity. A complete list of these dockets is contained in Exhibit No.___ (JTD-3). In addition to Need Determinations, Florida Law requires all public utilities in Florida, including Investor-Owned Utilities (IOUs), Municipals and Cooperatives, to annually submit Ten-Year Site Plans (TYSP) to the Florida Public Service Commission for review. As the name implies, each utility is required to forecast its demand needs and how that demand is to be met over a ten-year planning horizon. While the TYSPs are not docketed cases, the Florida Commission is required to review them for their suitability for planning purposes. The Commission's review includes such matters as accuracy of demand forecasts, conservation and DSM programs, fuel diversity and reliability of fuel supply considerations and transmission adequacy. I have participated in each of these annual reviews for the last 16 years.

Q: On whose behalf are you appearing?

A: I am presenting testimony on behalf of the advocacy staff of the North Dakota Public Service Commission.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to present the results of my review of the Big Stone II generating plant being proposed by Otter Tail Power Company and Montana-Dakota Utilities Company (MDU). My review was conducted from an overall regulatory policy perspective. My goal is to offer assistance that will be helpful to the North Dakota Public Service Commission in making its decision on the pending applications.

Q: What was the extent of your review?

A: I read the testimony of all company witnesses, reviewed their exhibits and reviewed the Power Plant Site Evaluation Study presented by Otter Tail. I prepared three separate sets of Data Requests submitted to Otter Tail and reviewed the responses. I visited Otter Tail's offices in Fergus Falls along with Mr. Mike Diller during the week of April 9, 2007. During that week we were given the opportunity to interview company personnel familiar with Big Stone II.

Q: Was your review limited to North Dakota specific information?

A: No, it was not. I also reviewed publicly available information from the Energy Information Administration, the Federal Energy Regulatory Commission (FERC), the Midwest Independent Transmission System Operator (MISO), the Surface Transportation

Board and the United States Environmental Protection Agency. I also reviewed open or recently concluded cases, similar to the Big Stone II applications, in three other states: Florida, Nevada and North Carolina.

Q: Will you please summarize your overall understanding of the Big Stone II project?

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

Q: Please describe supercritical generating technology.

A: Supercritical technology employs higher operating pressures providing increased efficiencies, which result in greater fuel economy and reduced emissions. Supercritical is a proven and reliable generating technology. There are currently more than 160 supercritical units operating in the United States, representing 15% of total fossil-fuel capacity. Based upon my research, it appears to be the technology of choice for large (greater than 500 MWs) baseload generating units.

Q: What was the process utilized by Otter Tail and MDU that resulted in their applications for Big Stone II?

A: The exact process utilized by any given utility to conclude there is a need for new generation capacity will obviously vary from utility to utility. However, there are general steps common to most utilities and these steps were utilized by both Otter Tail and MDU.

Q: What is the first step in this process?

A: The first step is an Integrated Resource Plan (IRP) which continually projects future demand, monitors existing generating resources and evaluates the resources (both demand side and supply side) needed to meet future demand which exceeds existing resources. The goal is to achieve an optimal mix of demand and supply side resources to meet future demand with a reasonable reserve margin.

Both MDU and Otter Tail have undertaken integrated resource planning. MDU's IRP is based on a 1987 Order of the North Dakota Public Service Commission, while Otter Tail's is based on Minnesota requirements. Both plans rely on the traditional least cost approach to resource planning. A summary of the more relevant portions of MDU's IRP is contained in Exhibit No.___ (JTD-4). A similar summary for Otter Tail is contained in Exhibit No. ___ (JTD-5). Both of these exhibits were prepared in consultation of Ms. Annette Bendish of the North Dakota Staff.

Q: Was a Request for Proposal (RFP) process used by MDU?

A: Yes. MDU issued an RFP for a baseload resource beginning in 2011. Only two responses were received. One did not meet the requirements of the RFP and the other had deliverability problems with no real cost advantage over Big Stone II.

Q: Was a RFP process used by Otter Tail?

A: Yes, as described in Exhibit ___ (JTD-5), Otter Tail's only response was from the Manitoba Hydro Electric Board (MHEB). The proposals did not meet Otter Tails' need for long-term dispatchable baseload generation.

Q: How was the site for the needed baseload generation selected?

A: Otter Tail retained Burns & McDonnell to conduct a Power Plant Site Evaluation Study. The purpose of the study was to identify a preferred site within the states of Minnesota, North Dakota and South Dakota for a new coal-fired generating plant. The study was quite comprehensive, beginning with 38 preliminary site areas that were narrowed to six specific candidate sites. Each of the six candidate sites were then subjected to a rigorous numerical screening process based on six categories: 1) Air Impacts; 2) Water Supply; 3) Environmental; 4) Fuel Supply; 5) Transmission; and 6) Other.

Q: What was the result of the numerical screening process?

A: Big Stone was selected as the preferred site with a numerical score of 397.7. The preferred alternative site was determined to be Utica Junction with a score of 383.3.

Q: Was Coyote Station evaluated as one of the six candidate sites?

A: Yes, it was. Coyote Station received a score of 339.6, but was eliminated because of "serious flaws" concerning air quality and transmission issues. The air quality concern is based on Coyote's proximity to two Class I Prevention of Significant Deterioration (PSD) areas: Theodore Roosevelt National Park (73 miles) and Lostwood National Wildlife Refuge (94 miles). The transmission concern is based on the fact that the existing transmission system does not have the capacity for additional power exports out of the North Dakota Lignite Mining area. The study concludes that the necessary transmission upgrades to accommodate the 600 MWs at Coyote Station would be "very expensive." The study did not attempt to quantify the exact costs.

The study gave Coyote a score of "2" for the category addressing Class I Area Proximity. This was the lowest score given for this category, while Big Stone received a "5," the highest score possible. The study gave Coyote a score of "1" for the category addressing transmission system impacts, the lowest possible score. Big Stone received a "4" for this category.

Q: Was a sensitivity analysis performed as part of the Site Evaluation Study?

A: Yes, it was. Six different sensitivities were performed, by giving each of the six screening categories a double weighting and reducing each of the remaining five screening category weights proportionately, so that the total weight for all categories would still equal 100%. In each one of the sensitivities, Big Stone had an overall ranking of either 1 or 2, with the best overall average rank of 1.43. Coyote performed poorly in the sensitivities with an overall average rank of 3.86. This lower ranking was primarily influenced by the air quality sensitivity and the transmission sensitivity, where Coyote received the lowest possible rank of 6.

An interesting sensitivity for Coyote was the fuel sensitivity where Coyote received a relatively high rank of 2. I believe this results because Coyote is the only candidate site that has significant potential for fuel delivery competition. The existence of significant fuel delivery competition would be a strategic advantage of the Coyote site.

Q: Did the Site Evaluation study attempt to quantify the impact of fuel delivery competition?

A: The study gave an overall weighting of 6.67% out of 100% to this category and then gave a score of from 1 to 5 to each candidate site. No attempt beyond this was made to quantify the impact of fuel delivery competition.

Q: Are you aware of any attempts in other jurisdictions to quantify the impact of fuel delivery competition?

A: Yes, I am. Florida Power and Light Company (FPL) in its Report on Clean Coal Generation concluded that a lack of competition (e.g., having access to only one port, or having access to only one railroad) would result in a significantly higher delivered price for coal. The Report quantified the net present value of the additional cost to be $383 million. This amount was calculated in relation to FPL's pending application to build two 980 MW ultra supercritical coal units in Glades County, Florida. FPL concluded that without fuel delivery competition, the calculated $435 million savings of the ultra supercritical coal units as compared to an all-gas alternative would be reduced to only $52 million. This caused FPL to further conclude: "It is therefore very important that a robust competitive coal transportation plan be established prior to making a final decision to implement clean coal generation."

I do not vouch for FPL's $435 million calculation. I realize it is for two units comprising 1,960 MWs of capacity compared to Big Stone II's 630 MW. I further realize that transportation costs represent a higher proportion of overall fuel costs for FPL than for MDU or Otter Tail, and that FPL has the potential for waterborne transportation alternatives which are not available to MDU and Otter Tail. The reference to FPL's Report is given merely to demonstrate the potential significance of the lack of fuel delivery competition and to give an example of an effort to actually quantify it.

Q: Within the Site Evaluation Study, did you review the specific scores given to Coyote for each of the category weightings?

A: Yes, I did. There were three specific scores given that I believe merit further consideration.

First, Coyote received the lowest possible score of "1" for Potential Airspace Restrictions. This score was given based only on the distance to the nearest airport, which in Coyote's case is 1.8 miles from the Beulah Airport. However, given that Coyote is a brownfield site and that the Beulah Airport runway is oriented east-west while Coyote is located due south of the airport, this low score may not be warranted. The Site Evaluation Study concluded that it is unlikely there would be any airspace restrictions that would limit the height of additional structures such as chimneys at Coyote.

Second, Coyote received the lowest possible score of "1" for Surface Water Proximity. This score was given based only on the distance from the site area to a potential water source, which in Coyote's case is 26 miles from Lake Sakakawea. However, given that Coyote is a brownfield site with an existing supply pipeline with adequate capacity and that the water supply is adequate without significant impacts on other water users, this low score may not be warranted.

Third, Coyote received the lowest possible score of "1" for Highway Access. This score was given based only on the distance to a U.S. or Interstate Highway, which in Coyote's case is 25 miles to Interstate 94. However, given that Coyote is an existing generating site with access provided by State Highway 49, this low score may not be warranted.

Q: **Did you perform a sensitivity analysis in regard to the three scores you just referenced?**

A: Yes, I did. For ease of reference, I prepared a spreadsheet showing the weightings for all categories and the corresponding scores for each of the six candidate sites, as originally contained in the Site Evaluation Study. The total scores for each candidate site may differ slightly due to rounding. This spreadsheet is attached to my testimony as Exhibit No. __(JTD-6).

For the specific scores I discuss above, I changed the score from "1" to "5" and recalculated the total score. This recalculation is attached to my testimony as Exhibit No.__ (JTD-7). This recalculation shows that Coyote attains a score of 385.1, the second highest score and only slightly below Big Stone II's 397.7. If more weight were given to Fuel Delivery Competition this disparity is further reduced. Giving equal weight to Rail Line/Mine Proximity and Fuel Delivery Competition would reduce Big Stone II's advantage over Coyote to less than 5 points. This recalculation is shown on Exhibit No. __ (JTD-8).

Q: **What do you conclude from these sensitivity recalculations?**

A: Sensitivities are meaningful in evaluating impacts of changed assumptions or inputs in complex calculations. However, it is difficult to draw hard and fast conclusions from sensitivities.

I do believe that the sensitivities show that Coyote should remain a viable candidate site for future generation expansion plans. I do acknowledge that Coyote has serious issues with proximity to Class I PSD areas as well as serious transmission concerns. However, Coyote offers a strategic advantage with its potential for fuel delivery competition.

Coyote's proximity to Class I PSD areas is a significant challenge, but one which deserves greater scrutiny in future site evaluations. While proximity is a good initial screen, there are other considerations beyond mere proximity. A Class I PSD increment is the maximum allowable increase in concentration from new emissions that is allowed to occur above a baseline concentration for a given pollutant. The allowable increments are not stagnant and can be affected by changes at other source emitters and changes in pollution control technology.

Coyote also faces significant challenges on the transmission side. Like Class I PSD areas, transmission is not a stagnant consideration. In fact, the transmission analysis for Big Stone II shows that its location will enable greater flows from west to east. Therefore, if Big Stone II and its transmission is built along with the Cap-X 2020 transmission infrastructure, the existing transmission constraints for Coyote may be substantially mitigated. This possibility merits further review for any future generation expansion.

Q: Did MDU and Otter Tail engage in a review of available generating technologies and analyze their cost impacts?

A: Yes, they did. MDU retained PA Consulting Corporation to perform a base case generation expansion plan which concluded that MDU's participation in Big Stone II yielded the lowest cost expansion option. The results are presented in MDU's Generation Expansion Plan Analysis dated October 2, 2006 and are discussed by Mr. Heidell in his testimony.

MDU, Otter Tail and the other Co-Owners retained Burns & McDonnell to evaluate several generation alternatives, including pulverized coal, wind plus combined cycle natural gas, integrated coal gasification combined cycle (IGCC) and 50 MW of biomass. This evaluation concludes that 630 MWs of supercritical pulverized coal is the lowest cost option. The results are presented in two reports: Analysis of Baseload Generation Alternatives dated September 2005 and Revised Analysis of Baseload Generation Alternatives dated October 2, 2006.

Q: Did you review these reports?

A: Yes, I did. All of the reports are quite comprehensive and involve intricate modeling with forecasted assumptions and corresponding economic and engineering inputs. The Burns & McDonnell reports also contain sensitivity analyses including high and low cases for fuel costs and capital costs. I placed a greater emphasis on reviewing the Revised Burns & McDonnell report as it contains more current information and more specific information relevant to Big Stone II as proposed. I reviewed the PA Consulting Report as corroborative to the Burns & McDonnell reports.

Q: Please summarize your understanding of the Revised Burns & McDonnell report.

A: The Revised Burns & McDonnell Report narrows the focus to three alternatives: 630 MW Supercritical Pulverized Coal (BS II); 500 MW Natural Gas Fired Combined Cycle Gas Turbine (CCGT); and 500 MW Gas Fired Combined Cycle Gas Turbine plus Wind (CCGT+Wind). The report shows the levelized busbar costs for each alternative both on an Investor Owned Utility (IOU) basis and a Public Power basis. In each case, BS II is the clear winner on a busbar cost basis, with little difference between the busbar costs for the CCGT and the CCGT+Wind alternatives. The degree to which BS II is cost effective is greater for the Public Power scenario than for the IOU scenario. This is because BS II is more capital intensive and Public Power benefits from a lower cost of capital. BS II's cost advantage in the IOU scenario is $11.16/MWh ($69.62/MWh vs. $80.78/MWh for CCGT+Wind). This cost advantage shrinks substantially as sensitivities are run regarding the Wind Production Tax Credit (PTC) and a carbon dioxide (CO_2) environmental cost value.

Q: Does a busbar cost analysis include all costs?

A: A busbar cost analysis is quite comprehensive and includes capital costs, Operating and Maintenance (O&M) costs and fuel costs (but not fuel inventories). There was some ambiguity as to whether it included Interest During Construction (IDC). In response to Data Request No. 11 of the 2nd Set, Otter Tail indicates that the busbar costs do include IDC. The busbar cost analysis does not include transmission costs.

Q: Is a busbar cost analysis a good tool to evaluate alternative generation technologies?

A: It is certainly a good tool but must be tempered with other policy concerns and strategic considerations. It should be viewed with an understanding of the assumptions and projected inputs on which it is based. And obviously, transmission costs and impacts must also be considered.

Q: What are the more important inputs utilized by Burns & McDonnell in the revised busbar cost analysis?

A: There are many different inputs which have a meaningful impact on the revised busbar cost analysis and which give insight into the reasonableness of the busbar cost results. I will categorize the more meaningful of these inputs into the following categories for ease of discussion: Wind Inputs; Construction Inputs; Operating Inputs; Fuel Inputs; Financial Inputs; and Other Assumptions.

Q: What are the wind inputs?

A: The original input for wind purchases was \$50/MWh in 2011 without consideration of the PTC. When the revised analysis was updated for 2006 costs, the new wind farm costs were estimated to be \$40/MWh in 2006 with the PTC. This amount was escalated by 2.5% per year to result in a \$46.39 cost in 2012. Recognizing that the impact of the PTC should be \$20/MWh or higher, the resulting cost of wind in 2012 was estimated at \$66/MWh. This amount was conservatively reduced to \$60/MWh for use in the busbar cost analysis. It is Burns & McDonnell's position that both the 2.5% annual escalation rate and the \$60/MWh cost are conservative inputs.

Whether the \$60/MWh cost for wind in 2012 is in fact conservative is dependent on both the annual escalation rate and the continuation or discontinuation of the PTC. In regard to the PTC, Otter Tail, in response to Data Request No. 16 of the 2nd Set, stated that a general consensus belief is that the PTC will receive an extension beyond 2008 but that it will be completely gone by approximately 2013. In any event there is a sensitivity analysis assuming a continuation of the PTC included in the Burns & McDonnell analysis.

In regard to the 2.5% annual escalation rate, this input is particularly significant because the cost of wind is assumed to be purchases as opposed to actual ownership of the resource. It is not clear why the wind option was assumed to be purchases, particularly when Otter Tail is actively engaged in acquiring ownership interests in wind generation. Of particular interest is the wind assumption used by Mr. Heidell in MDU's Generation Expansion Plan Analysis. Mr. Heidell used a capital cost of $1,500/KW for wind in 2006 and deescalated it to $1,200/KW in 2011. Even though the Burns & McDonnell study is measuring the cost of wind purchases and Mr. Heidell is apparently modeling the cost of wind ownership, there seems to be an inconsistency in the direction of wind costs. Perhaps the wind purchases are assumed to follow the marginal cost of generation which is heavily influenced by natural gas prices. Nevertheless, there appears to be an inconsistency between the two reports which should be explained.

Another potential inconsistency between Mr. Heidell and the Burns & McDonnell report is the assumed capacity factor for wind generation. Mr. Heidell assumes a 22% capacity credit for summer months. Burns & McDonnell assumes wind will supply enough energy to displace a 40% capacity factor on the CCGT operations. These two assumptions are not measuring the exact same parameter. One is measuring capacity and the other is measuring an amount of energy displacement and stating it in terms of an overall capacity factor. Therefore, there may be no inconsistency at all. If the 40% capacity factor used by Burns & McDonnell is in fact generous, it would only make BS II's cost advantage over the CCGT+Wind option that much more conservative. The differences in these two assumed parameters should be explained.

Another significant assumption concerning the CCGT+Wind alternative is the need for the wind portion to be "backed-up" by an equivalent amount of CCGT generation on a MW-to-MW basis. This means that the wind portion is assumed to provide no capacity benefits. This appears to be inconsistent with Mr. Heidell's assumption that wind provides a 22% capacity credit for the summer months. I understand that Otter Tail is a winter peaking utility and it is not clear that wind would provide capacity in the winter months. If wind does provide capacity, a lesser amount of CCGT capacity would be needed to be paired with the wind alternative. This scenario would cause the CCGT+Wind to have a slightly lower busbar cost.

Q: **What are the construction related inputs which materially impact the busbar cost analysis?**

A: The most obvious and significant input is the estimated capital cost expressed in \$/KW. In the original busbar cost analysis the capital cost for BS II was estimated to be \$1,800/KW in 2011. This was revised upward in the revised busbar analysis to \$2,168 in 2012, an increase of over 20%. Even at this much higher capital cost level, the revised busbar analysis still shows BS II to be the more cost-effective alternative.

In its April 19, 2007 response to Data Request No. 10 of the 2nd Set, Otter Tail indicates that the revised busbar analysis reflects the latest estimates. However, in an interview with Mr. Rolfes on April 10, 2007, he indicated that the capital costs used in the revised busbar cost analysis would need to be updated to reflect a later inservice date for BS II. He indicated that the capital costs would need to be increased by 6.5% (13 months @ 6% per annum). If this is done, the resulting capital cost for BS II would be approximately $2,300/KW. This increase would have a more material impact on BS II's resulting busbar cost, since capital costs comprise such a greater portion of BS II's overall costs. This coupled with the fact that the capital cost of the CCGT+Wind alternative is assumed to only escalate at 2.5% per year, could have a material effect on the busbar costs of BS II as compared to the CCGT+Wind alternative. Whether the impact would be material enough to change the conclusion that BS II is the lower cost alternative is unclear. I believe MDU and Otter Tail need to clarify the impact of BS II's increasing capital cost estimates.

Another significant construction related input is the estimated construction period of 48 months for BS II. This certainly may be achievable, but is likely optimistic. To the extent the actual construction time is within the assumed 48 months, there is a lesser potential for increase in materials and labor. In addition, the impact of IDC would be minimized and the benefits of asset-backed sales and lower fuel costs would be achieved sooner. To the extent construction takes longer than 48 months; there would be greater upward pressure on costs and postponement of anticipated benefits. Managing the construction time will be particularly challenging given the growing demand that numerous other proposed coal units will place on available resources.

Q: How many other coal plants will be under construction?

A: I do not know the exact number, but I have read reports that the United States is entering an acute period of increased coal generation development. I have also seen projections for as many as 45 coal plants to be under construction during the 2008 to 2013 timeframe. With so much competing activity, delays in the delivery of major equipment or difficulties in obtaining adequate skilled labor for a project the size of BS II may occur. I understand there already are backlogs in specialty fabrication facilities, including steam turbines, boilers and fuel handling equipment. The availability and cost of skilled labor may also be affected by construction related to refineries, post-Katrina activities and an overall aging of the work force.

Q: What are the operating inputs which materially impact the busbar cost analysis?

A: There are two operating parameters of particular interest: capacity factor and heat rate. Capacity factor is the percentage of time the plant is expected to be available for generation, taking into account both forced outages and unforced (maintenance) outages. For a baseload unit such as BS II, it is critically important that it have a high capacity factor. A high capacity factor means the relatively high capital costs are actually achieving the anticipated savings in lower fuel and operating costs. In fact, the sensitivity analysis shown in the original busbar cost analysis shows capacity factor to have an extremely large impact on BS II's resulting busbar cost, second only to BS II's capital costs. For purposes of the busbar cost analysis an overall capacity factor of 88% was assumed. I believe the 88% capacity factor is a conservative assumption.

The heat rate is a measure of the thermal efficiency of the plant and is stated in terms of Btu/KWh. The lower the heat rate value, the greater the efficiency. The original busbar cost analysis used a heat rate of 9,369 which was changed to 9,095 for the revised busbar analysis. The 9,095 is a conservative value as Mr. Rolfes indicates the current projected heat rate for BS II is 8,988 Btu/KWh. To the extent an actual heat rate closer to Mr. Rolfes' projection is actually achieved, the lower the resulting busbar costs.

Q: **What are the fuel cost inputs which materially impact the busbar cost analysis?**

A: Fuel costs may very well be the single most significant input in a busbar cost analysis which compares coal-based generation technologies with gas-based generation technologies. Fuel costs may also be the most difficult input to forecast.

The revised busbar cost analysis assumes a delivered price of PRB coal of $1.71/MMBtu in 2010 escalated at 2.9% per year. The original busbar cost analysis utilized an escalation rate of 2.0% per year. Given that the transportation component exceeds the commodity portion of the delivered price of PRB coal and that there is uncertainty concerning future transportation costs for PRB coal, increasing the overall escalation rate is probably justified. Mr. Heidell used an escalation rate of 2.5% for coal in his analysis, indicating that the 2.9% escalation is conservative. The $1.71/MMBtu cost of coal in 2010 is essentially the same as that used by Mr. Heidell of $1.68/MMBtu in 2010.

Q: **What about the natural gas cost inputs?**

A: 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. While it is difficult to predict the price of natural gas, it can be the single most important factor in justifying the relatively high capital costs of a solid fuel generating plant like BS II.

The revised busbar cost analysis assumes a delivered price of natural gas of $7.60/MMBtu in 2011 with a 3.0% annual escalation rate. The original busbar cost analysis used a 2.5% annual escalation rate. Mr. Heidel did not use a constant escalation rate in his analysis. Rather, he utilized PA Consulting's long-term consensus gas forecast which predicts gas price reductions in the early years followed by escalating increases in the later years. Mr. Heidel's forecast is consistently lower than that used by Burns & McDonnell. It is unclear whether Mr. Heidell's forecast is a commodity-only forecast or if it also includes transportation costs. The Burns & McDonnell forecast includes transportation at $0.40/MMBtu and then escalates it by 3.0% per year. A comparison of the two natural gas price forecasts is shown in Exhibit No.__(JTD-9).

Q: Why is there a difference in the two natural gas price forecasts?

A: As I said earlier, predicting natural gas prices is inherently uncertain so it is not surprising that knowledgeable people will have different forecasts. However, Mr.

Heidell's forecast is consistently lower than that used by Burns & McDonnell in its revised busbar cost analysis. Part of this difference could be attributable to transportation costs. Nevertheless, the differences are quite large, greater than 20% in many years, and they are consistent in their magnitude and their direction of deviation.

Q: Could these differences impact the conclusions of the revised busbar cost analysis?

A: Yes, it is possible. The original busbar cost analysis contained sensitivity analyses for a number of inputs, including fuel costs. The fuel cost sensitivity was for both a high cost and a low cost case, at 10% above and below the forecasted values. Even in the low fuel cost case, the busbar cost of BS II was still lower than that of the gas-based alternatives. However, there was no fuel cost sensitivity presented in the revised busbar cost analysis. It is not clear whether a fuel cost sensitivity was performed for the revised busbar cost analysis and, if it was, what it showed. Even if it was performed, I would assume it would have been done for the 10% sensitivity case. The difference between the Burns & McDonnell forecast and the PA Consulting forecast exceed 20% in most years. I believe MDU and Otter Tail should explain the differences in the gas forecasts and determine the potential impacts on the revised busbar cost results, if any.

Q: What are the financial inputs which materially impact the busbar cost analysis?

A: There are essentially three major categories of financial inputs that materially impact the busbar cost analysis: cost of capital; forecasted lives; and tax considerations. Assumptions for these inputs are distinguished between the IOU case and the Public Power case. I will concentrate on the IOU assumptions.

The revised busbar cost analysis assumes an interest rate of 7.5% on debt and a cost of equity capital of 12.0%. These rates combined with an assumed 50%/50% debt to equity ratio results in an overall cost of capital rate of 9.75%. The 9.75% is used as the discount rate in the model used to calculate the busbar costs.

The busbar cost analysis is based on a 20-year economic model analysis. It also assumes a book life of 30 years and a tax life of 20 years. The effective tax rate (for IOU's only) is assumed to be 40%.

Q: Are the financial inputs used in the revised busbar cost analysis appropriate?

A: I generally agree that the financial inputs used are appropriate for modeling purposes, as is the case in the revised busbar cost analysis. In many cases, I believe the financial inputs used are not only appropriate, but are actually conservative. Obviously, inputs that are appropriate for modeling busbar costs may not be appropriate for other purposes such as ratemaking.

Q: Will you specifically address the cost of capital inputs?

A: Yes, I will. First, let me say that a company's cost of capital is specific to that company and is based on many qualitative as well as quantitative considerations. It is beyond the scope of this testimony to fully explore all of those considerations. However, I have made some general observations which indicate that it is not necessary, for purposes of this testimony, to distinguish possible differences between MDU and Otter Tail. My review indicates that the two companies share many similarities.

Besides their close geographic proximity, they both have substantial interests in non-utility lines of business. While MDU, in terms of total assets is larger on a consolidated basis, Otter Tail's regulated electric business is larger, in terms of both net plant and income, than MDU's regulated electric business. MDU and Otter Tail have other similarities including equity ratio, interest coverage and bond rating. These and other financial comparisons are shown in Exhibit No. ___ (JTD-10).

The assumed 7.5% interest rate appears conservative. Both MDU and Otter Tail have strong financial indicators with the apparent ability to access the capital markets on reasonable terms. The companies' existing interest costs compare favorable to the assumed 7.5%. The current yields on A3 rated electric utility debt with an approximate 20-year maturity are averaging around 6%. While markets can change, it is reasonable to assume that the necessary debt to construct Big Stone II should be available at a rate at or below 7.5%. To the extent debt can be acquired considerably less than 7.5%, the resulting busbar cost of Big Stone II will also be less.

While the companies' current consolidated equity ratios are substantially greater than 50%, it should be recognized that these are consolidated equity ratios reflecting substantial non-regulated businesses. Also, electric capital expenditures are forecasted to greatly exceed historical averages. Therefore, substantial amounts of debt in excess of historical levels will have to be acquired for Big Stone II. A 50%/50% debt to equity ratio is reasonable under these circumstances.

The use of a 12% return on equity is also reasonable. This return is not out of line when compared to returns historically granted. I believe it is reasonable given the financial stress that an undertaking the size of Big Stone II will have on the electric operations of MDU and Otter Tail. While the actual return on equity will be the product of a future rate proceeding, the use of 12% for the busbar cost analysis is certainly reasonable.

Q: Are the forecasted lives used in the busbar cost analysis reasonable?

A: Yes, they are. The busbar cost analysis assumes an economic term of 20 years. This is a reasonable term to use when comparing competing generation alternatives. Certainly the impacts of any years beyond 20 would have a lesser significance on a net present value basis and would introduce greater uncertainties in forecasted inputs. However, the true economic life of a plant like Big Stone II is anticipated to be much greater than 20 years, probably by a factor of two. This means that assuming all other things (like relative fuel and operating costs) being equal, a unit like Big Stone II should generate savings well beyond the 20 year planning horizon. This phenomenon is known as "end effects" and is referenced by Mr. Heidell in his testimony. To the extent the end effects materialize, the busbar cost of Big Stone II would be less over its actual economic life.

The busbar cost analysis also assumes a book life of 30 years and a tax life of 20 years. The 30-year book life is certainly conservative. Mr. Heidell used a book life of 40 years. The difference in the book life and the tax life would generate deferred income taxes in the early years that would eventually reverse over the life of the unit. It is not clear whether the busbar cost analysis includes the beneficial effects of the deferred taxes. I assume it does not since the simplified capital structure assumption is a 50% equity/50% debt. To the extent deferred taxes are not considered, it would yield a conservative result. If deferred taxes were considered and all other things held equal, Big

Stone II (given its higher capital costs) would have an even lower busbar cost relative to other generation alternatives.

Q: Are there other assumptions which impact the busbar cost analysis?

A: Yes, there are two other assumptions which merit some brief discussion.

First, the busbar cost analysis assumes that the construction of each alternative is executed under an Engineer-Procure-Construct (EPC) Contract. Under this approach a single contract is entered into which covers all aspects from initial design to final construction. This is a reasonable assumption to make when comparing competing generation alternatives. However, an EPC Contract is not the basis upon which Otter Tail and the other Co-owners plan to proceed if Big Stone II is approved. In an interview conducted April 10, 2007, Mr. Rolfes indicated that multiple contracts will be pursued for Big Stone II with Black & Veatch acting as Construction Manager. This should allow for more control and more competition from vendors, resulting in lower costs. To the extent multiple contracts are pursued and costs are lower, it should have a greater benefit for Big Stone II relative to the other generating alternatives.

Second, the busbar cost analysis assumes no gypsum sales from Big Stone II. This is certainly the conservative approach to take and avoids having to make assumptions about quantities and prices in the gypsum market. However, in reality, gypsum sales should provide some revenue to help offset some of the costs of Big Stone II. Obviously, gypsum revenue would not be available from any of the other generating alternatives.

Q: Are there other considerations which go beyond the limitations of a busbar cost analysis?

A: Yes, there are. By definition, busbar costs do not include transmission costs. Obviously, transmission is an extremely important consideration which I will discuss later in my testimony. Also, significant is the manner in which Big Stone II would fit into MDU and Otter Tail's generation fleet and how it would be dispatched in relation to other units. Also potentially significant is the possibility of Big Stone II facilitating additional asset-backed sales either from Big Stone or other generating units within MDU's and Otter Tail's systems.

Q: Why are asset-backed sales an important consideration?

A: Asset-backed sales provide a benefit to the selling utility by providing additional revenue above the marginal costs of generation, thus providing a contribution toward fixed costs. These sales also provide a benefit to the buying utility by displacing higher cost generation.

Different jurisdictions have different policies when it comes to asset-backed sales. I am familiar with Florida's system of sharing the gains between customers and stockholders. This provides an incentive for companies to pursue such sales, thus benefiting themselves and their customers.

I understand that MDU has a similar arrangement that was part of a negotiated settlement whereby there is an 85%/15% sharing between customers and stockholders. To the extent Big Stone II were to facilitate additional asset-backed sales, this would be a significant benefit to MDU's customers. I understand that Otter Tail does not have a sharing requirement but is recognizing these sales in their financial reporting of regulated operations.

Q: What is your understanding of the interconnection requirements of Big Stone II?

A: Big Stone II would be connecting at the same location as Big Stone I, which is in Otter Tail's control area. MISO has the responsibility to process interconnection requests and to evaluate impacts on the grid. Otter Tail took the lead in performing an interconnection study and submitting it to the MISO. The study identified two primary options for achieving interconnection, the preferred alternative being a new upgraded line from Big Stone to Morris, Minnesota, and a new line from Big Stone to Granite Falls, Minnesota. The Big Stone to Morris line would be designed to operate at 230 kV while the Big Stone to Granite Falls line would be designed to operate at either 230 kV or 345 kV. The Big Stone to Morris line would utilize an existing transmission corridor.

Q: Are there requirements beyond interconnection?

A: Yes, there are. To determine the deliverability of the power from Big Stone II to the loads of the various Co-owners, a delivery service study was performed by Otter Tail and submitted to the MISO. This study identified facility upgrades which would generally enhance the overall grid and more specifically enable the output to be delivered to the intended recipients. The result of the delivery service study did not change the conclusion of the interconnection study.

Q: What is the anticipated cost of all transmission facilities associated with Big Stone II?

A: Transmission planning and costing is a dynamic process. It is a constant evaluation of the effects of changes to the system and of synergies that will most cost-effectively meet changing needs. Therefore, anticipated costs will change over time. Nevertheless, the latest cost projection for Big Stone II's transmission, including costs relating to interconnection, delivery, contingencies and escalation is approximately $215 million. This amount includes cost escalations to 2012 and recognizes $35 million of savings for delivery service facilities. The original transmission cost estimate was $238 million.

Q: Are there other cost savings possible?

A: Yes, there is always the possibility that other savings (or increases) will be identified. There also is the likelihood that some of Big Stone II's transmission cost will be shifted to others. MISO has a Regional Economic Criteria Benefit tariff on file with the FERC where other MISO members pay a portion of certain transmission enhancements. A preliminary analysis performed by Otter Tail indicates that others would be allocated about $8 million of Big Stone II's transmission costs, assuming the transmission line from Big Stone to Granite Falls is constructed and operated as proposed at 345 kV.

Q: How does the cost of Big Stone II's transmission compare to the cost of transmission from 600 additional MWs at Coyote Station?

A: This question was posed to Mr. Rogelstad in an interview conducted on April 11, 2007. He indicated that an interconnection study for Coyote Station was not performed. He offered as a surrogate the results of a preliminary study for the interconnection of 600

MWs of additional capacity at Center, North Dakota. This study shows interconnection costs substantially greater than those estimated for Big Stone II. To my knowledge, no studies were performed for delivery costs at any location other than Big Stone II.

Q: Is Center a good surrogate for estimating the cost of additional transmission for Coyote?

A: Yes, I believe it is. A Transmission System Impact Study performed as part of the Lignite Vision 21 Project shows that the cost of transmission for Coyote is within $4 million of that needed for Center. These results were reported in February, 2001.

Q: Are there constraints that limit the amount of energy which can be exported out of North Dakota?

A: Yes, in his testimony, Mr. Rogelstad refers to the North Dakota Export transmission constraint, which also includes a portion of western Minnesota and eastern South Dakota. He also refers to the transient stability problem that arises when large amounts of generation are connected to distant loads with less than optimal transmission. Contingency analyses show that in those circumstances the tripping of a single transmission line can cause severe voltage swings, sometimes resulting in separation and outages.

Q: Would the transmission requirements for Big Stone II mitigate this constraint?

A: Yes, while the transmission requirements for Big Stone II are consistent with the addition of 630 MWs and are designed to allow the energy to be transmitted to the intended recipients, the addition of Big Stone II will have a beneficial effect on the ability of the entire system to transmit energy from west to east.

Under existing circumstances, Big Stone I provides a beneficial effect. Without Big Stone I, the west-to-east capability of the system is reduced by 350 MWs. With the addition of Big Stone II, the beneficial effect is further increased. It is estimated that with Big Stone II up to 500 MWs of generation could be added in North Dakota and that the transient stability performance of the system would meet current reliability standards.

Q: Is this conclusion supported by MISO?

A: I am not aware of any attempts by MISO to estimate the amount of additional export capability Big Stone II would create. However, MISO is keenly aware of the west-to-east constraint. MISO recently evaluated 1300 MWs of transmission service requests, excluding Big Stone II, in a general west-to-east direction. This evaluation shows a need for additional transmission capacity and identified a number of individual constraints on the system. In testimony filed on behalf of MISO in Minnesota, MISO stated:

> *The Big Stone upgrades in conjunction with the Cap-X 2020 proposed lines resolved 61 constraints in a study that analyzed 1300 MW of transmission service plus the 600 MW of Big Stone. The upgrades in and of themselves did not single-handedly remove those constraints, but rather the integration of the plans of the Big Stone upgrades to those proposed in Cap-X 2020 resolved the constraints.*

MISO went on to conclude that the transmission upgrades associated with Big Stone II would be used and useful even without Big Stone II's 630 MWs of additional capacity.

Q: Would the construction of Big Stone II take transmission capacity away from potential wind generators?

A: The addition of Big Stone II would not take away any existing transmission capacity that may exist for wind. Any generating capacity expansion requires adequate transmission capacity to match it and Big Stone II is not exempt from this requirement.

There already exists a long queue of potential wind generators seeking interconnection. MISO has concluded that the 345 kV portion of the Big Stone II facilities along with the Cap-X line from Brookings to the Twin Cities would enable more wind generation to interconnect. Therefore, it is conceivable, that Big Stone II would be assisting the development of more wind generation, not taking away from it.

Q: Did MISO take a position on Big Stone II before the Minnesota Public Utilities Commission?

A: Yes, MISO took the position that Big Stone II transmission should be approved.

Q: What will be the coal requirements for Big Stone II, if approved?

A: Big Stone II would burn sub-bituminous coal from the PRB, similar to what Big Stone I has been burning since 1995. Big Stone II is being designed to burn 8400 Btu/lb coal, but could also burn fuel with a higher heat content.

Big Stone I currently burns approximately 2 million tons of coal annually. Big Stone II would be expected to burn approximately 2.5 million tons annually. A historical summary of Big Stone I's coal usage is shown in Exhibit No__ (JTD-11).

Q: Would Big Stone II be able to burn fuels other than coal, similar to Big Stone I?

A: Yes, but probably not to the extent of Big Stone I. Big Stone I has burned a variety of "opportunity fuels" that have included tire-derived fuel and waste corn and seeds. There are a variety of independent suppliers of such fuels, which are delivered by truck. The prices paid for such fuels are generally 70% or less than that paid for the plant's primary fuel. Big Stone II would be able to burn some biomass fuels on a limited basis.

Q: **Has Otter Tail entered into any contracts or bid solicitations for coal supply for Big Stone II?**

A: No, Otter Tail has not yet done so. Given that Big Stone II is only in its preliminary approval stage, it would be premature and perhaps impractical to require fully negotiated fuel supply contracts. It is my understanding that if Big Stone II is approved, Otter Tail would issue RFPs to those mines that can supply coal to the correct specifications, similar to what is currently done for Big Stone I. However, it is imperative that the current economic evaluation of Big Stone II contain reasonable estimates of future fuel costs. The projected cost of coal for Big Stone II is shown in Exhibit No.___(JTD-12).

Q: **Are the projected costs of coal shown in this exhibit consistent with the projected costs in the revised busbar cost analysis?**

A: Yes, I believe so with one clarification. The revised busbar cost analysis begins with the 2010 estimated cost of $1.71/MMBtu and escalates it by 2.9%. It is not clear whether this is a constant escalation rate or an average escalation rate. The projected cost shown in Exhibit No.___(JTD-12) is not based on a constant escalation rate, but still reflects an overall annual escalation rate of 2.9%. I have added two columns to Exhibit No.__(JTD-12) to show the differences that result from using a constant 2.9% escalation rate. For ease of reference, these additional columns are shown in Exhibit No.__(JTD-13). The differences are not great but do show lower escalated values in the earlier years compared to greater escalated values in the later years. This would tend to show a slightly lower busbar cost on a net present value basis.

Q: **Do you believe these differences are material?**

A: No, I do not. Unless there is a severe distortion between the earlier and later years, it should make no material difference whether the escalation rate is constant or an annual average.

Q: **Is the 2.9% escalation rate appropriate?**

A: Forecasting fuel costs is difficult. While forecasting the costs of natural gas may be the most challenging, coal presents its own set of problems. Coal is generally not a worldwide or even a national commodity. It tends to be based on regional markets where users have a limited ability to switch from one region to another. Regional prices tend to be set by the marginal cost of production to satisfy demand. While production costs for PRB coal are generally less, demand has been steadily increasing. Another complicating factor for PRB coal is transportation costs. For western sub-bituminous coal, rail transportation costs represent about 60% of overall cost, while it is only about 25% for eastern bituminous.

Given these uncertainties, I believe a 2.9% escalation rate is reasonable. It is just slightly lower than the recent actual escalation experienced at Big Stone I and is in line with recent forecasts from the Energy Information Administration. While it is slightly higher than the 2.5% escalation rate by Mr. Heidell, I believe it is reasonable given the uncertainly of rail transportation costs.

Obviously, the higher the escalation rate used in the busbar cost analysis, the higher the confidence that Big Stone II is the most cost-effective alternative. If Big Stone II is approved and the actual cost of coal is less, the savings would be even greater.

Q: **What if Big Stone II is approved and the actual escalation rate of coal is greater than forecasted?**

A: The actual escalation rate could be higher or lower. If it is higher, Big Stone II would not be as cost-effective, holding all other factors equal. However, in all likelihood, if coal costs escalate greater than forecasted then natural gas costs would also escalate greater than forecasted. The true test of Big Stone II's cost effectiveness would be its overall operating costs compared to the overall operating costs of the other alternatives, which are highly dependent on natural gas costs. The question for today is whether the 2.9% escalation rate is reasonable. For our purposes, I believe it is.

Q: **Why is the rail transportation of coal such a critical concern?**

A: The transportation component of any fuel is an important concern. However, for PRB coal it is even more critical. On an absolute basis, transportation exceeds the commodity portion of the overall cost of PRB coal. Beyond that, transportation adds a level of uncertainty both in the cost and its reliability of delivery.

Q: **Why is the cost of rail transportation for Big Stone II such a critical concern?**

A: There is no competition for this service and thus no competitive pressure to keep these costs down. The section of Otter Tail's 2006 Annual Report discussing Risk Factors identifies this and states:

> *We are a captive rail shipper of the Burlington Northern Santa Fe Railroad for shipments of coal to our Big Stone and Hoot Lake plants, making us vulnerable to increased prices for coal transportation from a sole supplier.*

Earlier in my testimony I discussed the strategic advantage of having fuel delivery competition. Unfortunately, this is not an option for Big Stone.

Q: Have there been efforts to mitigate this risk factor?

A: Yes, to MDU's and Otter Tail's credit, they have pursued relief from the Surface Transportation Board (STB). This action was prompted by a 38% increase in their freight rates from 1999 to 2000. They sought a favorable rate with a 20-year term that would be based on a least-cost replacement standard to simulate a competitive rate. The STB rejected this standard and used a cross-subsidy test under which the rate was found to not only be permissible but also subject to further potential increases. This decision was appealed to the 8th Circuit Court of Appeals where the STB decision was reaffirmed on May 1, 2007.

Q: Have there been reliability problems with the delivery of coal to Big Stone I?

A: Yes, there have been. The delivery disruptions got so severe that there were generation curtailments which began on March 11, 2006, and lasted through May 4, 2006. On March 11, 2006, the normal 30-day supply of coal had been depleted to only

10 days, while the train cycle times had increased by more than 20%. The initial curtailments were to 70% of full load and on April 6 there were further curtailments to 45% of full load. It is estimated that 115,000 MWhs of generation were lost due to the supply disruptions.

Q: What has caused the supply disruptions from the PRB?

A: There were many reasons that contributed to the problem. One of the most obvious was structural failures of rail roadbeds triggered by a combination of coal dust and unusually wet weather. Another significant factor was the record growth of coal production from the region. The Energy Information Administration (EIA) reports that coal production in the Western Region, primarily from mines in Wyoming and Montana, increased by 800% from 1973 to 2003. This was followed by three record production years from 2003 to 2006. By 2006, the Western Region accounted for over 53% of total U.S. coal production.

Q: Have the railroads responded to the increase in production?

A: The EIA reports that both the BNSF Railway Company and the Union Pacific Railroad have made substantial improvements that address both the need to strengthen the existing system and to increase its capacity. Mr. Brautovich addresses BNSF's efforts in this overall effort as well as efforts to address Big Stone II's specific needs.

Q: If Big Stone II is approved, what, if anything, can the co-owners do to address potential coal delivery problems?

A: The options available may be limited. First, the co-owners do not have the option of negotiating with a competing carrier. And based upon responses to data requests and interviews with knowledgeable individuals at Otter Tail, it does not appear that negotiating performance guarantees with BNSF Railway Company is a viable option.

There are a number of internal operational measures the co-owners could undertake, however, to enhance the timely and efficient delivery of coal. First, cycle times should be closely monitored. Cycle time is the amount of time that it takes a train to move from the load point, through loaded transit, unloading, and unloaded transit back to placement for loading again. This is important as a measure of equipment utilization when owned or leased railcars are being used. This also gives an early indication of rail congestion and possible future shipment slow downs.

Second, there should be a forecasted schedule of train loadings for each month and for each set of equipment, based upon the burn requirements for each plant. This schedule should be communicated to the railroad. The loadings should be monitored to determine if the schedule is being met. If the schedule is not being met, there should be an effort to coordinate with the railroad to speed up cycle times or place more train sets in service.

Third, there should be a system to manage train deliveries. In most cases the generating plant must move coal away from the unloading area before it can unload the next train. This becomes more critical if a train arrives within a short time of the previous unloading. It is important to monitor the expected times of arrival as scheduled and compare them to the actual times of arrival. Moving coal out of the way unnecessarily when a train arrives late is costly and delaying trains from unloading when they arrive early is poor utilization of rail equipment.

Fourth, there should be a target number of cars per unit train and enough railcars to hit those targets plus maintenance spares. The actual number of cars per train should be monitored to verify that the targets are being met.

Q: **Does Otter Tail use these measures for the delivery of coal to Big Stone I?**

A: The operational measures I just described should be part of an overall coal delivery management system. I believe Otter Tail undertook many of these measures in response to the earlier delivery problems at Big Stone I. They may also be part of Otter Tails' ongoing coal delivery procedures. I believe Otter Tail should indicate if this is the case, how these measures fit into their overall management system and whether there is any formalized reporting of these measures. If Otter Tail plans not to engage in these practices for Big Stone II, I believe they should explain why.

Q: **If approved, would Big Stone II use light weight aluminum railcars?**

A: I am not sure of the type of rail cars planned for Big Stone II. It may not be possible to determine which railcars would serve which plant. It is my understanding that there would be a common coal-handling facility for both Big Stone I and Big Stone II, creating cost savings and adding to their overall efficiency.

To the extent additional railcars would be needed to serve the additional coal requirements of Big Stone II, I believe the use of light weight aluminum railcars should be considered. There would be a trade-off between cost and capacity that would need to be considered. However, the cost may be justified, particularly considering past coal delivery problems at Big Stone I.

Q: **What is the significance of using aluminum railcars?**

A: The significance is basically twofold. First, the per ton shipping rate is less for aluminum railcars than that for steel railcars. According to the BNSF Tariff, the savings is slightly more than 5%. Second, an aluminum railcar can carry 121 tons on average compared to 100 tons on average for a steel railcar. If congestion on the system persists, getting more tons per train set may be crucial in maintaining adequate inventories.

Q: Is there any other measure that could be taken to minimize the effect of potential coal delivery problems?

A: Yes, the coal inventory level could be increased. It is my understanding that Big Stone II would have a target inventory of 30 days burn, which should be adequate under most circumstances. However, as planned, it would be possible to have up to 45 days of inventory on site.

Q: Would there be a cost associated with increasing the amount of fuel inventory?

A: Yes, there is an end-of-year inventory tax collected by South Dakota, there could be some additional Operation and Maintenance (O&M) expenses and there is also the potential for some coal quality degradation. There also would be the carrying costs of the additional inventory.

Q: What would be the amount of the carrying costs on the additional inventory?

A: This is largely dependent upon the cost of coal you assume. Assuming a delivered cost of PRB coal of $30/ton, I calculated the additional inventory to be slightly over $3 million. MDU and Otter Tail would each be responsible for 19.33% of this amount or approximately $600,000 each. The carrying cost of this amount, including income taxes, would be less than $100,000 per year. These calculations are shown in Exhibit No.__(JTD-14).

Q: **Would a 45-day inventory of coal have prevented the earlier curtailments at Big Stone I?**

A: A 45-day inventory would probably not have totally prevented the curtailments. However, it is reasonable to conclude that it would have mitigated the degree of curtailments. My calculations show that Big Stone I experienced curtailments equal to approximately 23 days of full load capacity (26 days at 30% curtailment and 28 days at 55% curtailment). These curtailments were begun when the inventory had been depleted to a level of 10 days burn.

Q: **What was the cost of purchasing replacement power to cover the curtailments at Big Stone I?**

A: According to Otter Tail's response to Data Request No. 8 of the 3rd Set, the cost of replacement power itself was in a range of $2.1 million to $2.8 million. The incremental costs (those costs over what Big Stone's costs would have been assuming no curtailments) were in a range of $1.0 million to $1.7 million.

Q: **If Big Stone II is approved, what level of coal inventory should it maintain?**

A: My understanding is that Big Stone II would have a target inventory of 30 days burn, like Big Stone I. I also understand that the Engineering and Operating Committee for Big Stone I has on occasion increased the target level to address supply concerns. I believe Big Stone II should be no different. In light of the recent supply disruptions, I believe that the target level should once again be reviewed to determine if a higher target is cost justified. Given the high cost of replacement power, having a higher inventory may be justified even if the likelihood of future curtailments is remote.

Q: What agreements have MDU and Otter Tail entered into to govern the development and operation of Big Stone II?

A: MDU, Otter Tail and the other Co-owners have entered into three agreements, the Participation Agreement, the O&M Agreement and the Joint Facilities Agreement. Northwestern Corporation, one of the co-owners of the existing Big Stone I Plant, is also a signatory to the Joint Facilities Agreement.

Q: Have you reviewed these agreements?

A: Yes, I have. The agreements address matters in great detail and address numerous contingencies. The operating parameters are generally patterned after the Big Stone I agreement.

The Participation Agreement is an agreement to jointly develop, finance, construct, own and manage Big Stone II. It includes provisions which obligate the parties to obtain financing and pay their share of costs. It also addresses withdrawal rights due to higher than anticipated project costs. Amendments extend these rights until June 2007. The Participation Agreement establishes a Coordinating Committee and an Engineering and Operating Committee to manage all aspects of Big Stone II and to supervise the plant operator. Decisions at the Engineering and Operating Committee have to be unanimous. Other matters are addressed by the Coordination Committee for resolution.

The O&M Agreement designates Otter Tail as the operator of Big Stone II. The operator is required to provide staff and resources for the development, design, financing, construction and operation of Big Stone II. The other Co-owners are required to reimburse Otter Tail for their allocated share of these costs. In addition to the recovery of all costs associated with being the operator, Otter Tail also receives a $500,000 per year fee as operator. Under the agreement, it is permissible for Otter Tail to share this fee with its employees. Otter Tail is the designated operator for at least the first five years.

The Joint Facilities Agreement provides for the transfer of certain real property and easements from Big Stone I participants to Big Stone II participants. It also provides for the shared use of certain equipment and facilities and for the allocation of associated costs.

Q: What facilities would be shared between Big Stone I and Big Stone II?

A: There would be many different facilities that could be shared now and perhaps even more in the future. Sharing the facilities would provide significant cost savings. Three of the most significant would be coal handling facilities, water intake facilities and the wet scrubber.

Q: Does Big Stone I currently have a wet scrubber?

A: No, it does not. If Big Stone II is approved, it is contemplated that a common wet scrubber would be installed for both units. This would create a tremendous cost savings for Big Stone I. It is estimated that a wet scrubber can be added with enough capacity to scrub both units at an incremental cost of only 60% of scrubbing Big Stone II alone. The incremental cost of the scrubber would be allocated to big Stone I. The wet scrubber as designed would remove 98% of SO_2 and would collect the fly ash. It would also create

SO_2 allowances. It also could potentially allow both Big Stone I and Big Stone II to look at higher sulfur coal as a future fuel supply.

Q: How would you characterize the risk of proceeding with Big Stone II?

A: Adding coal-fired base load generation like Big Stone II presents a myriad of uncertainties and thus risks. However, these risks must be weighed against the advantages of this type of generation. One should also evaluate the risks of not proceeding.

Q: What are the significant areas of uncertainty associated with Big Stone II?

A: I have discussed various areas of uncertainty in answers to previous questions. I will attempt to summarize them here.

First is the uncertainty of the timing of the benefits. It is important to recognize that the higher capital costs of Big Stone II would be incurred at the outset while the anticipated benefits, such as lower and more stable fuel costs, would be realized gradually over the plant's operating life. There would be a commitment to higher capital costs with the expectation, but no guarantee, that the commitment would create savings in the long-term.

Second is the uncertainty of the various fuel price forecasts and whether the fuel price differential between coal and natural gas narrows or widens in the future. To the extent the differential narrows the cost advantage of Big Stone II would diminish.

Third is the uncertainty concerning the price and reliability of rail transportation for PRB coal. This could have a material impact on the fuel price differential discussed previously and the overall availability of the unit.

Fourth is the uncertainty of the actual operating performance of the plant in terms of efficiency (heat rate) and availability (availability factor). While there is some level of uncertainty here, I tend to discount it for Big Stone II. Supercritical technology is proven to be both efficient and reliable, assuming coal is available.

Fifth is the uncertainty of currently unknown but potential future environmental regulations. Such regulations could significantly increase the capital and O&M expenses of Big Stone II. The actual impact would depend on the form, extent and timing of those new regulations and the market's response to them.

Sixth is the uncertainty of the actual capital cost of constructing Big Stone II. Longer construction times create a potential for the cost of equipment, materials and labor to change significantly. Other planned coal plants could also impact these costs.

And seventh is the uncertainty of the financial stresses Big Stone II could have on MDU's and Otter Tail's financial health. For MDU, Big Stone II would approximately double its existing amount of net electric plant. For Otter Tail, it would be an increase of over 50%. These are significant increases and, even after recognizing the benefits on fuel costs, would almost certainly necessitate future rate relief.

Q: Are these uncertainties unique to Big Stone II?

A: No, not at all. All of the areas of uncertainty, with the possible exception of PRB coal deliveries, would also apply to other generating alternatives. It is a question of to what extent. A high capital cost alternative like Big Stone II simply makes the uncertainties more critical.

Q: What are the risks of not proceeding with Big Stone II?

A: If no new generation were pursued, both MDU and Otter Tail would be subject to the prices and availability of power on the market. While relying on the market can be successful for part of a utility's need in the short term, it would not be a good long term strategy. There would be too much price risk and potential adverse impacts on reliability.

If Big Stone II were not pursued and some alternative generating technology pursued in its place there would still be a myriad of risks specific to that alternative. If the alternative were gas-based, there would be significant risks associated with the price and availability of natural gas. And based upon the best information we have available at this time, the alternative would most likely be at a higher cost than Big Stone II. In addition, the strategic benefits of Big Stone II would be foregone.

Q: What are the strategic benefits of Big Stone II?

A: In answers to previous questions I have discussed various aspects of the benefits that Big Stone II would bring. I will summarize them here.

First, Big Stone II is based on a proven, reliable and efficient technology with low emission rates.

Second, Big Stone II is planned for an existing brownfield site with substantial infrastructure already in place and minimal environmental impacts. There will be the ability to share common facilities and to cost-efficiently install a wet scrubber which also benefits Big Stone I. The scrubber also enables the possibility for sales of gypsum.

Third, Big Stone II would be owned by a group of utilities. No single co-owner could undertake a project the size of Big Stone II. By participating, MDU and Otter Tail could gain the benefits and efficiencies of a large base-load unit that otherwise would not be available to them. As operator, Otter Tail would also receive an annual $500,000 fee above its incremental costs.

Fourth, Big Stone II would be dispatchable and add to the reliability of MDU's and Otter Tail's systems. It also could act as back-up generation for future wind projects.

Fifth, Big Stone II would enhance the possibility of asset-backed sales with their accompanying benefits.

Sixth, Big Stone II would burn a domestic fuel in plentiful supply. It would have a relatively stable supply of fuel in terms of price and availability. This would be in contrast to the price of natural gas which can be priced high on a Btu basis and is prone to sharp fluctuations.

Seventh, Big Stone II would enhance the reliability of the transmission grid and increase the potential for export capabilities out of North Dakota. This potentially could allow for additional generation, wind or coal, to be constructed within North Dakota.

And eighth, the projected life of Big Stone II would be 40 plus years. Depending on future costs of other generation, this could provide substantial "end effect" benefits.

Q: **Should Big Stone II be approved and given an advanced determination of prudence?**

A: I believe Big Stone II should be approved with some needed clarifications and subject to some potential conditions.

Q: **What are the needed clarifications?**

A: As discussed earlier in my testimony, there are a number of ambiguities or inconsistencies within the revised busbar cost analysis that need an explanation. First there are some inconsistencies on wind costs and assumptions including capacity factor and the need for back-up. I discuss these on pages 14 through 16 of my testimony. Second is the impact of Big Stone II's latest capital cost forecast in relation to the capital costs of other alternatives and the resulting busbar cost differentials. I discuss this on pages 16 and 17 of my testimony. Third is the differences in the forecasts of natural gas prices. I discuss this on pages 19 through 21.

Based upon my review, I doubt these ambiguities and inconsistencies would change the conclusion of the revised busbar cost analysis that Big Stone II is the lowest cost alternative. However, this is not something that I can confirm. I would invite Otter Tail to address these matters and confirm whether the conclusion of the revised busbar cost analysis is still valid.

Q: Are there other clarifications needed?

A: Yes, I believe Otter Tail should clarify to the Commission how they propose to treat any additional asset-backed sales that may result from the addition of Big Stone II. I also believe Otter Tail should clarify whether Coyote Station would remain a potential site for future expansion plans and what impacts, positive or negative, Big Stone II would have on the prospects of future generation in North Dakota.

Q: What are the conditions you suggest for granting the advance prudence determination for Big Stone II?

A: There are five conditions I suggest the Commission consider before granting an advance determination of prudence. While these conditions are not necessarily required, I believe they would be helpful to the Commission in carrying out its on-going regulatory oversight.

First is a simple requirement to make periodic informational filings on the progress of obtaining all necessary approvals, permits and licenses from other regulatory bodies and an indication when construction commences.

My second suggested condition is a reporting requirement as contemplated by Section 49-05-16 of the North Dakota Century Code. At or shortly prior to construction commencement, Otter Tail should file a forecasted budget by year for all construction related costs. Within the budget should be information on the results of RFPs (subject to confidentiality protections) for all major components of the plant. This first report should be followed by at least annual updates with an analysis of deviations between actual and budget and explanations of changes in forecasts for future years. If at any time the co-owners determine that the prudence, economic viability or continuation of the project is in jeopardy, there should be an immediate filing indicating the reasons for such determination.

Given that the deliverability of coal is fundamentally critical to the success of Big Stone II, my third suggested condition involves coal delivery and management. At pages 37 and 38 of my testimony I describe operational measures that can be undertaken to better manage the delivery of coal. These measures may already be part of Otter Tail's management system. If they are, I believe there should be a confirmation of this. If they are not, Otter Tail should either confirm that they will be incorporated for Big Stone II or explain why they are inappropriate. If these measures are to be utilized, I believe the accompanying information and management reports produced should be available for periodic review by the Commission.

My fourth suggested condition also addresses coal deliverability. I believe Otter Tail should be required to conduct a study of the number of rail cars necessary to serve Big Stone II and do a cost/benefit analysis of whether any additional rail cars should be light weight aluminum railcars. The results of this study should be filed with the Commission in sufficient time before the commercial operation of Big Stone II so as to enable Commission review of the report.

My fifth and final suggested condition involves coal inventory. Given that the cost of maintaining coal inventory above 30 days may be less than the adverse consequences of potential generation curtailments, I believe Otter Tail should perform a study which calculates the cost of having a higher inventory level. The cost should be compared to the cost and likelihood of curtailments from inadequate fuel deliveries. The results of the study along with Otter Tail's recommendations should be filed with the Commission in sufficient time before the commercial operation of Big Stone II so as to enable Commission review of the study and its conclusions.

Q: **Does this conclude your testimony?**

A: Yes, it does.

Exhibit No.___ (JTD-1)
2 pages

RADEY THOMAS YON CLARK

Attorneys & Counselors at Law

Terry Deason*

Special Consultant (Non-lawyer)

Post Office Box 10967 (32302)

301 South Bronough Street, Suite 200

Tallahassee, Florida 32301

Phone: (850) 425-6654

Fax: (850) 425-6694

E-Mail: tdeason@radeylaw.com

Practice Areas:

- Energy, Telecommunications, Water and Wastewater and Public Utilities

Education:

- United States Military Academy at West Point, 1972
- Florida State University, B.S., 1975, Accounting, summa cum laude
- Florida State University, Master of Accounting, 1989

Professional Experiences:

- Florida Public Service Commission, Commissioner, 1991 - 2007
- Florida Public Service Commission, Chairman, 1993 - 1995, 2000 - 2001
- Office of the Public Counsel, Chief Regulatory Analyst, 1987 - 1991
- Florida Public Service Commission, Executive Assistant to the Commissioner, 1981 - 1987
- Office of the Public Counsel, Legislative Analyst II and III, 1979 - 1981
- Ben Johnson Associates, Inc., Research Analyst, 1978 - 1979
- Office of the Public Counsel, Legislative Analyst I, 1977 - 1978
- Quincy State Bank Trust Department, Staff Accountant and Trust Assistant, 1976 - 1977

Professional Associations and Memberships:

- National Association of Regulatory Utility Commissioners (NARUC), 1993 - 1998, *Member, Executive Committee*
- National Association of Regulatory Utility Commissioners (NARUC), 1999 - 2006, *Board of Directors*

Terry Deason, Special Consultant (Non-lawyer)

- National Association of Regulatory Utility Commissioners (NARUC), 2005-2006, *Member, Committee on Electricity*
- National Association of Regulatory Utility Commissioners (NARUC), 2004 - 2005, *Member, Committee on Telecommunications*
- National Association of Regulatory Utility Commissioners (NARUC), 1991 - 2004, *Member, Committee on Finance and Technology*
- National Association of Regulatory Utility Commissioners (NARUC), 1995 - 1998, *Member, Committee on Utility Association Oversight*
- National Association of Regulatory Utility Commissioners (NARUC) 2002 *Member, Rights-of-Way Study*
- Nuclear Waste Strategy Coalition, 2000 - 2006, *Board Member*
- Federal Energy Regulatory Commission (FERC) South Joint Board on Security Constrained Economic Dispatch, 2005 - 2006, *Member*
- Southeastern Association of Regulatory Utility Commissioners, 1991 - 2006, *Member*
- Florida Energy 20/20 Study Commission, 2000 - 2001, *Member*
- FCC Federal/State Joint Conference on Accounting, 2003 - 2005, *Member*
- Joint NARUC/Department of Energy Study Commission on Tax and Rate Treatment of Renewable Energy Projects, 1993, *Member*
- Bonbright Utilities Center at the University of Georgia, 2001, *Bonbright Distinguished Service Award Recipient*

Exhibit No. ___ (JTD-2)
1 page

EXHIBIT ______

Dockets in which Mr. Deason testified:

In re: Application of Southern States Utilities, Inc. for a rate increase in Marion County, Docket No. 880520-WS, Florida Public Service Commission, 1988-89.

In re: Petition of Florida Power & Light Company for authority to increase its rates and charges, Docket No. 810002-EU, Florida Public Service Commission, 1981

In re: Petition of Florida Power Corporation for authority to increase its rates and charges, Docket No. 800119-EU, Florida Public Service Commission, 1980-81.

In re: Petition of Tampa Electric Company for authority to increase its rates and charges, Docket No. 800011-EU, Florida Public Service Commission, 1980-81.

In re: Petition of Gulf Power Company for an increase in its rates and charges, Docket No. 800001-EU, Florida Public Service Commission, 1980-82

In re: Petition of General Telephone Company of Florida to increase certain rates and charges, Docket No. 790084-TP, Florida Public Service Commission, 1979.

In re: Application of Florida Public Utilities Company-Marianna Division to increase its rates and charges, Docket No. 770652-EU, Florida Public Service Commission, 1977-78.

Exhibit No. ___ (JTD-3)
3 pages

EXHIBIT_____

Need Determination Dockets in which Commissioner Deason participated:

In re: Petition for determination of need for Seminole Generating Station Unit 3 electrical power plant in Putnam County, by Seminole Electric Cooperative, Inc., Docket No. 060220-EC, Florida Public Service Commission, 2006 (750 MW supercritical pulverized coal plant).

In re: Petition for determination of need for West County Units 1 and 2 electrical power plants in Palm Beach County by Florida Power & Light Company, Docket No. 060225-EI, Florida Public Service Commission, 2006 (two 1300 MW combined cycle units).

In re: Petition for determination of need for Hines 4 power plant in Polk County by Progress Energy Florida, Inc., Docket No. 040817-EI, Florida Public Service Commission, 2004 (517MW combined cycle unit).

In re: Petition for determination of need for expansion of electrical cogeneration power plant in Palm Beach County, by Florida Power & Light Company and New Hope Power Partnership, Docket No. 040766-EI, Florida Public Service Commission 2004 (70 MW steam turbine electric generator).

In re: Petition to determine need for an electrical power plant in Martin County by Florida Power and Light Company, Docket No. 020262-EI, Florida Public Service Commission, 2002-04 (789 MW additions to existing combustion turbine units).

In re: Petition to determine need for an electrical power plant in Manatee County by Florida Power & Light Company, Docket No. 020263-EI, Florida Public Service Commission, 2002-04 (1,100MW combined cycle unit).

In re: Petition for determination of need of Hines Unit 3 power plant, Docket No. 020953-EI, Florida Public Service Commission, 2002-03 (582MW combined cycle unit).

In re: Petition for determination of need for an electrical power plant in Lake County by Panda Leesburg Power Partners, L.P., Docket No. 000288-EU, Florida Public Service Commission, 2000-01 (1000MW combined cycle unit).

In re: Petition for determination of need for an electrical power plant in St. Lucie County by Panda Midway Power Partners, L.P., Docket No. 000289-EU, Florida Public Service Commission, 2000-01 (1000MW combined cycle unit).

In re: Petition for determination of need for an electrical power plant in St. Lucie County by Duke Energy St. Lucie, L.L.C., Docket No. 000612-EU, Florida Public Service Commission, 2000-01 (608MW combined cycle unit).

In re: Petition for determination of need for an electrical power plant in Okeechobee County by Okeechobee Generating Company L.L.C., Docket No. 991462-EU, Florida Public Service Commission, 1999-01 (550 MW combined cycle unit).

In re: Petition for determination of need for the Osprey Energy Center in Polk County by Seminole Electric Cooperative and Calpine Construction Finance Company, L.P., Docket No. 001748-EC, Florida Public Service Commission, 2000-01 (529MW combined cycle unit).

In re: Petition for determination of need of Hines Unit 2 Power Plant by Florida Power Corporation, Docket No. 001064-EI, Florida Public Service Commission, 2000-01)530MW combined cycle unit).

In re: Joint Petition for determination of need for an electrical power plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company, Ltd., L.L.P., Docket No. 981042-EM, Florida Public Service Commission, 1998-99 (514MW combined cycle unit).

In re: Petition to determine need for existing Tiger Bay Electrical Power Plant and nominal electrical capacity increase to that plant by Florida Power Corporation, Docket No. 971059-EI, Florida Public Service Commission, 1997 (increase of 12MW of steam electric capacity).

In re: Petition to determine need for electrical power plant in St. Marks, Wakulla County, by City of Tallahassee, Docket No. 961512-EM, Florida Public Service Commission, 1996-97, (250MW combined cycle unit).

In re: Petition for determination of need for proposed electrical power plant to be located in Hardee and Polk Counties by Seminole Electric Cooperative, Inc., Docket No. 931212-EC, Florida Public Service Commission, 1993-94 (440MW combined cycle unit).

In re: Petition to determine need for electrical power plant (Okeechobee County Cogeneration Facility) by Nassau Power Corporation, Docket No. 920769-EQ, Florida Public Service Commission, 1992-94 (75+ MW cogeneration).

In re: Joint Petition to determine need for electric power plant to be located in Okeechobee County by Florida Power and Light Company and Cypress Energy Partners, L.P., Docket No. 920520-EQ, Florida Public Service Commission, 1992-94 (MW unavailable).

In re: Petition of Ark Energy, Inc. and CSW Development for determination of need for electrical power plant to be located in Okeechobee County, Florida, Docket No. 920761-EQ, Florida Public Service Commission, 1992-94 (866MW combined cycle unit).

In re: Petition of Ark Energy, Inc. and CSW Development I for approval of contract for the sale of capacity and energy to Florida Power & Light Company, Docket No. 920762-EQ, Florida Public Service Commission, 1992-94.

In re: Petition of Nassau Power Corporation for approval of contract for the sale of capacity and energy to Florida Power & Light Company, Docket No. 920783-EQ, Florida Public Service Commission, 1992-94.

In re: Petition of Nassau Power Corporation to determine need for electrical power plant (Amelia Island Cogeneration Facility), Docket No. 910816-EQ, Florida Public Service Commission, 1991-92 (MW unavailable).

In re: Petition for determination of need for a proposed electrical power plant and related facilities in Polk County by Tampa Electric Company, Docket No. 910883-EI, Florida Public Service Commission, 1991-93 (220 MW integrated gasification combined cycle unit).

In re: Petition for determination of need for proposed electrical power plant and related facilities Polk County Units 1-4, by Florida Power Corporation, Docket No. 910759-EI, Florida Public Service Commission, 1991-1992. (940 MW-four combined cycle units).

Exhibit No. ___ (JTD-4)
3 pages

Integrated Resource Plan Review

Montana-Dakota

Montana-Dakota used an end-use forecasting model to develop a long-range (20-year) electric load forecast for Montana-Dakota's Integrated System which includes its service territories in Montana, North Dakota, and South Dakota.

Demand Side Management (DSM)

Montana-Dakota's DSM program includes programs such as load management, new uses of electricity, strategic conservation, electrification, and adjustments in market share. For an activity to be classified under DSM it must result from direct intervention on the part of the utility. In its IRP Montana-Dakota evaluated 12 residential programs and seven commercial programs. To determine whether a program is beneficial, Montana-Dakota relies on a benefit/cost ratio for the Ratepayer Test and the Societal Benefit Test. The Ratepayer Test includes all of the quantifiable benefits and costs of a given program and its impact on all ratepayers. The Societal Benefit Test measure the net costs of a management program based on its total costs including both the participant's and the utility's costs as well as including environmental externalities and excluding tax credit benefits.

Power Supplier Assumptions

A utility discount rate of 7.4 percent was used for the analysis. The discount rate is the weighted average cost of capital, based on the capital structure and associated interest rates forecasted for the long-range planning of resource needs for Montana-Dakota. The annual transmission and distribution losses represent and average of the losses that have occurred on Montana-Dakota's system. Montana-Dakota used 7.88 percent for residential and commercial program evaluations.

Analysis Procedure

Five programs were selected to be evaluated on a qualitative basis (Energy Star partner, commercial energy audits, continue load management rates, home energy audits, proper A/C sizing training seminars.) Montana-Dakota's DSM Model was used as the evaluation tool for the remaining 13 programs (promote Energy Star® applicants (4), high efficiency A/C residential, high efficiency A/C commercial, residential A/C cycling, refrigerator round-up, residential geo-thermal heat pump, electric heat incentives/promotion, commercial lighting T-8 retrofit, commercial lighting – LED exit, commercial A/C cycling)

Feasible Programs

The DSM programs that Montana-Dakota found feasible were:

- Residential Programs:
  - Promote Energy Star® refrigerators
  - Promote Energy Star® high-efficiency central air conditioners
  - Promote residential central air conditioner cycling
  - Promote residential refrigerator round-up
  - Promote uncontrolled electric heat (in North Dakota only)
- Commercial Programs:
  - Promote Energy Star® high-efficiency central air conditioners
  - Propose high-efficiency lighting (T-8 retrofit)
  - Promote commercial central air conditioner cycling

Montana-Dakota cannot implement all of the feasible DSM programs so two alternative options were packaged for consideration.

Option A:
Energy Star® Partnership
Promote uncontrolled electric heat (in North Dakota only)
Promote Energy Star® high-efficiency residential central air conditioners
Propose high-efficiency lighting (T-8 retrofit)

Option B:
Energy Star® Partnership
Promote uncontrolled electric heat (in North Dakota only)
Promote residential central air conditioner cycling
Promote commercial central air conditioner cycling

Montana-Dakota implemented the programs outlined in Option A in 2006.

<u>Supply-Side Resource Plan</u>

<u>Resource Plan</u>

In 2001 Montana-Dakota started planning for a baseload coal-fired plant. Montana-Dakota states that its IRP relies on the "least cost" IRP approach but also takes into consideration factors which are not captured in a strict least cost analysis. Montana-Dakota states that it also considered

- The benefits resulting from wholesale sales of off-peak energy provided by coal-fired, baseload units.
- Societal changes in environmental obligations due to changes in laws and regulations as well as changes in consumer attitude, which cannot be monetarily quantified.
- The possibility of new large load developing in Montana-Dakota's service territory from economic development efforts.
- Renewable resources, especially wind energy development. Total costs for wind turbines are depended on governmental incentives notwithstanding, wind energy investments result in relatively high costs for consumers.

For these reasons, Montana-Dakota states that it is proposing a supply-side resource plan that will consider economic, societal, governmental, and customer issues.

<u>Existing and Committed Resources</u>

In addition to its own generation, Montana-Dakota receives power from the Western Area Power Administration under Bill Crediting Program Arrangements and purchasing peak capacity from NorthPoint Energy and Northern States Power Company as part of its existing and committed resources. The agreement to purchase power from the Antelope Valley Station expired October 31, 2006.

<u>Future Baseload Capacity</u>

In its IRP Montana-Dakota states that it was pursuing four options with other utilities or partners:

- A 175 MW coal plant near Gascoyne, North Dakota to be on-line in 2010
- Part ownership of a 600 MW coal plant addition at the existing Big Stone plant near Big Stone, South Dakota to be on-line in 2011
- Part ownership of a 600-1200 MW coal project being considered for construction in one of five locations in the upper Midwest to be on-line in 2012 or later (The Resource Coalition), and
- Purchase of power from other utilities or from the energy market.

Big Stone II Unit

In April 2001, Otter Tail Power Company suggested developing a business plan for a second generating unit at Big Stone, South Dakota. The Big Stone II partners are still in the process of applying for a Certificate of Need with the Minnesota Public Service Commission for the construction of transmission facilities associated with the unit that will be constructed in Minnesota.

Resource Coalition Unit

In August 2003 Montana-Dakota joined a group of utilities known as the Resource Coalition to study the feasibility of a jointly owned coal-fired plant and potentially 100 MW of wind energy. The coalition members are Basin Electric Power Cooperative, Heartland Consumers Power District, Minnkota Electric Cooperative, Missouri Basin Power Agency, and Montana-Dakota. The Coalition has selected five potential plant sites for study: Gascoyne, North Dakota; Mobridge, South Dakota; Modale, Iowa; Stanton, North Dakota; and Yankton, South Dakota. Transmission, fuel supply, and other studies are underway for all sites.

Bridge Power

On January 9, 2004, Montana-Dakota signed a Participation Power Purchase/Sale Agreement with Omaha Public Power District (OPPD) to purchase the following amounts of capacity and associated energy:

- 70 MW for November and December 2006
- 80 MW for 2007
- 90 MW for 2008 and
- 100 MW for 2009 and 2010

The agreement was contingent on Montana-Dakota and OPPD securing confirmed firm transmission service to deliver power from OPPD's system to Montana-Dakota's customer load. The OPPD agreement was cancelled on December 31, 2004 because Montana-Dakota and OPPD could not secure the needed firm transmission service.

October 2004 Request for Proposals

On October 25, 2004 Montana-Dakota issued a request for proposals for the purchase of 70 to 100 MW of capacity and associated energy from November 1, 2006 through December 31, 2010. Three proposals were received. Of these, only one was a qualified bid and only offered a small portion of the needed capacity.

Exhibit No. ___ (JTD-5)
2 pages

Integrated Resource Plan Review

Otter Tail Power Company

Existing Resources
Current Otter Tail capacity resources are about 60% coal-fired in the winter and 65% in the summer. Almost two-thirds of the summer season capacity was from Manitoba Hydro.

Hydro
Otter Tail has six units located at five dams on the Otter Tail River and two units located at dam on the outlet of Lake Bemidji. The units on the Otter Tail River are FERC jurisdictional.

Peaking Facilities
Otter Tail has two fuel oil-fired combustion turbines at Jamestown and a third at Lake Preston, South Dakota. Prior to the 2003 summer season Otter Tail brought on-line a new dual-fuel combustion turbine. There are two internal combustion diesel units located at the Hoot Lake Steam Plant and one at Big Stone. A 2,000 kW diesel unit was installed at Otter Tail's System Control Center to serve as a standby generator for the facility, in accordance with NERC reliability criteria.

Otter Tail has worked with several customers who desire to install small diesel generators for back-up emergency power.

Baseload Resources
Otter Tail has partial or full ownership of five coal-fired generators located at three plants – Hoot Lake #1, 2, and 3, Big Stone, and Coyote Station.

Radio Load Management System
Otter Tail has an extensive radio load management system that is used to control annual peak demand and reduce the need for new generating capacity. The latest load management capability forecast was developed in 2002. Since then Otter Tail has undertaken a multi-year project to replace all load management equipment, transmitter and receivers.

Transactions
Otter Tail receives 2MW of capacity as payment from Minnkota Power Cooperative for control area services provided by Otter Tail. A capacity purchase of 50 MW from Manitoba Hydro has been executed from May 1, 2000 to April 30, 2010.

DSM Programs
The IRP only outlines projects that are part of the Company's Conservation Improvement Plan in effect in Minnesota.

Potential Resources
Capacity Purchases
Otter Tail contacted area utilities and other known entities within the region close to the Company's service territory to explore the potential to purchase long-term capacity and energy. To those entities that indicate having available resources or the expectation of available resources, a written Request for Proposal was issued. The only proposals received were from Manitoba Hydro Electric Board (MHEB).

Excelsior Energy was contacted in late 2003 to seek proposals from the planned coal gasification project in northern Minnesota, both by telephone and by issuance of an RFP. They declined to make a proposal.

Otter Tail received three proposals from MHEB in response to an RFP issued to them for baseload and peaking capacity proposals. The proposals included a variety of megawatts of capacity, energy availability, and options for load following service.

Supply-side Generation

The group of utilities involved in the Big Stone II plant investigated a number of baseload generation technologies including sub-critical pulverized coal, super-critical pulverized coal, atmospheric circulating fluidized bed combustion coal, integrated gasification combined cycle, and large natural gas-fired combined cycle. The group has selected a 600 MW super-critical pulverized coal-fired facility.

The IRP also evaluated phosphoric acid fuel cell, wind, hydro, pumped storage hydro, solar photovoltaic, anaerobic digestion, landfill gas, microturbines, biomass, geothermal, and conservation for its modeling.

Preferred Resource Plan

The Otter Tail preferred resource plan in the IRP is the plan selected by the IRP-Manager model with one change. The model selected an LM6000 for implementation in 2011. Otter Tail's review of the IRP-Manager base plan indicated the model elected more capacity in 2011 than is needed. According to the IRP the LM6000 could possibly be delayed until 2013, resulting in a cost savings to customers. The model selected 20 MW of wind in 2012 in addition to the wind manually implemented in the model, if the total cost to Otter Tail is 3 cents/kWh or less, flat cost, over the life of the installation. The model also selected 120 MW of the Big Stone II Plant. This was the maximum it was allowed to select. The IRP-Manager selected two small IGCC units for implementation in 2018 for reserve margin and energy needs.

As of the date of the IRP, Otter Tail had filed for approval of the 70.5 MW Enbridge Wind Farm. There is no mention of 40.5 MW in Cavalier County.

Otter Tail has identified three transmission projects that will result in reduction in transmission line losses. These three projects are the Appleton-Canby 41.6 kV to 115 kV update. Fargo-Mapleton 41.6 kV to 115 kV uprate, and the Audubon-Detroit Lakes-Frazee-Perham-Rush Lake 41.6 kV to 115 kV uprate.

Exhibit No. ___ (JTD-6)
1 page

Big Stone II
Site Evaluation Summary

Major Category/Criterion	Weight	Big Stone II Rank	Big Stone II Score	Coyote Rank	Coyote Score	Dickenson Rank	Dickenson Score	Fargo Rank	Fargo Score	Glenham Rank	Glenham Score	Utica Rank	Utica Score
Air Impacts	**15.00%**												
Proximity to Class I Area	10.71%	5	53.6	2	21.4	4	42.8	5	53.6	3	32.1	5	53.6
Potential Airspace Restrictions	4.29%	3	12.9	1	4.3	2	8.6	1	4.3	5	21.5	5	21.5
Water Supply	**20.00%**												
Surface Water Proximity	5.71%	5	28.6	1	5.7	3	17.1	3	17.1	5	28.6	3	17.1
Surface Water Supply Potential	14.29%	3	42.9	5	71.5	3	42.9	1	14.3	5	71.5	5	71.5
Environmental	**15.00%**												
Socioeconomics	2.22%	1	2.2	3	6.7	5	11.1	5	11.1	2	4.4	2	4.4
Land Use Compatibility	3.33%	5	16.7	5	16.7	1	3.3	3	10	3	10	3	10
Protected Species Impacts	1.11%	5	5.6	5	5.6	3	3.3	4	4.4	3	3.3	3	3.3
Noise Impacts	5.56%	5	27.8	5	27.8	1	5.6	4	22.2	5	27.8	3	16.7
Wetlands	2.78%	3	8.3	4	11.1	1	2.8	5	13.9	4	11.1	2	5.6
Fuel Supply	**20.00%**												
Rail Line/Mine Proximity	11.11%	5	55.6	5	55.6	4	44.4	2	22.2	1	11.1	3	33.3
Fuel Delivery Competition	6.67%	1	6.7	5	33.4	3	20	1	6.7	1	6.7	1	6.7
Reagent Delivery	2.20%	2	4.4	2	4.4	4	8.9	3	6.7	3	6.7	1	2.2
Electric Transmission	**20.00%**												
Proximity to Interconnection Point	2.67%	5	13.4	5	13.4	5	13.4	2	5.3	4	10.7	5	13.4
Expected System Impacts	17.33%	4	69.3	1	17.3	3	52	4	69.3	2	34.7	5	86.7
Other	**10.00%**												
Highway Access	1.25%	5	6.3	1	1.3	4	5	3	3.8	4	5	3	3.8
Land Availability	6.25%	5	31.3	5	31.3	3	18.8	5	31.3	5	31.3	5	31.3
Common Facilities/Staff	2.50%	5	12.5	5	12.5	1	2.5	1	2.5	1	2.5	1	2.5
Total	**100.00%**		**398.1**		**340**		**302.5**		**298.7**		**319**		**383.6**

Exhibit No. ___ (JTD-7)
1 page

Big Stone II
Site Evaluation Summary

		Big Stone II		Coyote		Dickenson		Fargo		Glenham		Utica	
Major Category/Criterion	Weight	Rank	Score	Rank	Score	Rank	Score	Rank	Score	Rank	Score	Rank	Score
Air Impacts	**15.00%**												
Proximity to Class I Area	10.71%	5	53.6	2	21.4	4	42.8	5	53.6	3	32.1	5	53.6
Potential Airspace Restrictions	4.29%	3	12.9	5	21.5	2	8.6	1	4.3	5	21.5	5	21.5
Water Supply	**20.00%**												
Surface Water Proximity	5.71%	5	28.6	5	28.6	3	17.1	3	17.1	5	28.6	3	17.1
Surface Water Supply Potential	14.29%	3	42.9	5	71.5	3	42.9	1	14.3	5	71.5	5	71.5
Environmental	**15.00%**												
Socieoeconomics	2.22%	1	2.2	3	6.7	5	11.1	5	11.1	2	4.4	2	4.4
Land Use Compatibility	3.33%	5	16.7	5	16.7	1	3.3	3	10	3	10	3	10
Protected Species Impacts	1.11%	5	5.6	5	5.6	3	3.3	4	4.4	3	3.3	3	3.3
Noise Impacts	5.56%	5	27.8	5	27.8	1	5.6	4	22.2	5	27.8	3	16.7
Wetlands	2.78%	3	8.3	4	11.1	1	2.8	5	13.9	4	11.1	2	5.6
Fuel Supply	**20.00%**												
Rail Line/Mine Proximity	11.11%	5	55.6	5	55.6	4	44.4	2	22.2	1	11.1	3	33.3
Fuel Delivery Competition	6.67%	1	6.7	5	33.4	3	20	1	6.7	1	6.7	1	6.7
Reagent Delivery	2.20%	2	4.4	2	4.4	4	8.9	3	6.7	3	6.7	1	2.2
Electric Transmission	**20.00%**												
Proximity to Interconnection Point	2.67%	5	13.4	5	13.4	5	13.4	2	5.3	4	10.7	5	13.4
Expected System Impacts	17.33%	4	69.3	1	17.3	3	52	4	69.3	2	34.7	5	86.7
Other	**10.00%**												
Highway Access	1.25%	5	6.3	5	6.3	4	5	3	3.8	4	5	3	3.8
Land Availability	6.25%	5	31.3	5	31.3	3	18.8	5	31.3	5	31.3	5	31.3
Common Facilities/Staff	2.50%	5	12.5	5	12.5	1	2.5	1	2.5	1	2.5	1	2.5
Total	**100.00%**		**398.1**		**385.1**		**302.5**		**298.7**		**319**		**383.6**

Exhibit No. ___ (JTD-8)
1 page

Big Stone II
Site Evaluation Summary

		Big Stone II		Coyote		Dickenson		Fargo		Glenham		Utica	
Major Category/Criterion	Weight	Rank	Score	Rank	Score	Rank	Score	Rank	Score	Rank	Score	Rank	Score
Air Impacts	**15.00%**												
Proximity to Class I Area	10.71%	5	53.6	2	21.4	4	42.8	5	53.6	3	32.1	5	53.6
Potential Airspace Restrictions	4.29%	3	12.9	5	21.5	2	8.6	1	4.3	5	21.5	5	21.5
Water Supply	**20.00%**												
Surface Water Proximity	5.71%	5	28.6	5	28.6	3	17.1	3	17.1	5	28.6	3	17.1
Surface Water Supply Potential	14.29%	3	42.9	5	71.5	3	42.9	1	14.3	5	71.5	5	71.5
Environmental	**15.00%**												
Socieoeconomics	2.22%	1	2.2	3	6.7	5	11.1	5	11.1	2	4.4	2	4.4
Land Use Compatibility	3.33%	5	16.7	5	16.7	1	3.3	3	10	3	10	3	10
Protected Species Impacts	1.11%	5	5.6	5	5.6	3	3.3	4	4.4	3	3.3	3	3.3
Noise Impacts	5.56%	5	27.8	5	27.8	1	5.6	4	22.2	5	27.8	3	16.7
Wetlands	2.78%	3	8.3	4	11.1	1	2.8	5	13.9	4	11.1	2	5.6
Fuel Supply	**20.00%**												
Rail Line/Mine Proximity	8.90%	5	44.5	5	44.5	4	35.6	2	17.8	1	8.9	3	26.7
Fuel Delivery Competition	8.90%	1	8.9	5	44.5	3	26.7	1	8.9	1	8.9	1	8.9
Reagent Delivery	2.20%	2	4.4	2	4.4	4	8.9	3	6.7	3	6.7	1	2.2
Electric Transmission	**20.00%**												
Proximity to Interconnection Point	2.67%	5	13.4	5	13.4	5	13.4	2	5.3	4	10.7	5	13.4
Expected System Impacts	17.33%	4	69.3	1	17.3	3	52	4	69.3	2	34.7	5	86.7
Other	**10.00%**												
Highway Access	1.25%	5	6.3	5	6.3	4	5	3	3.8	4	5	3	3.8
Land Availability	6.25%	5	31.3	5	31.3	3	18.8	5	31.3	5	31.3	5	31.3
Common Facilities/Staff	2.50%	5	12.5	5	12.5	1	2.5	1	2.5	1	2.5	1	2.5
Total	**100.00%**		**389.2**		**385.1**		**300.4**		**296.5**		**319**		**379.2**

Exhibit No. ___ (JTD-9)
1 page

Natural Gas Price Forecasts

	Burns & McDonnell		PA Consulting	
	Price	Escalation	Price	Escalation
Year	$/MMBtu	Rate	$/MMBtu	Rate
2011	7.60		6.58	
2012	7.83	3.0%	6.53	(-).8%
2013	8.06	3.0%	6.77	3.7%
2014	8.31	3.0%	6.90	1.9%
2015	8.55	3.0%	6.92	0.3%
2016	8.81	3.0%	7.10	2.6%
2017	9.08	3.0%	7.21	1.5%
2018	9.35	3.0%	7.39	2.5%
2019	9.63	3.0%	7.77	5.1%
2020	9.92	3.0%	8.06	3.7%
2021	10.21	3.0%	8.38	4.0%
2022	10.52	3.0%	8.69	3.7%
2023	10.84	3.0%	9.00	3.6%
2024	11.16	3.0%	9.34	3.8%
2025	11.50	3.0%	9.70	3.9%

Exhibit No. ___ (JTD-10)
1 page

Comparison of Selected Financial Statistics
As of December 31, 2006
(In millions where applicable)

	MDU	Otter Tail
Consolidated Total Assets	$4,904	$1,259
Net Electric Plant	$320	$561
Net Income from Electric Operations	$14.4	$24.2
Consolidated Equity Ratio	65%	64%
Consolidated Interest Coverage	6.3x	6.2x
Covenants Restrictions		
Maximum Debt Ratio	65%	60%
Minimum Coverage	2.5x	1.5x
Moody's Bond Rating	A3	A3
Average Per Year Electric Capital Expenditures		
Actual 2004 - 2006	28.3	30.0
*Projected	144.7	155.2

*2007-2009 for MDU
*2007-2011 for Otter Tail

Exhibit No. ___ (JTD-11)
1 page

Big Stone I Coal Usage

Year	BS I $/ton	BS I Btu/lb	BS I $/MMBtu	Type of Fuel	Source of Fuel
1990	14.083	6096	1.155	Lignite	Gascoyne Mine
1991	13.719	6026	1.138	Lignite	Gascoyne Mine
1992	13.862	6034	1.149	Lignite	Gascoyne Mine
1993	13.279	6060	1.096	Lignite	Gascoyne Mine
1994	13.224	6049	1.093	Lignite	Gascoyne Mine
1995	14.624	9033	0.809	Lignite/ Subbituminous	Gascoyne Mine/Absaloka/ Spring Creek
1996	16.847	8990	0.937	Subbituminous	Absaloka/Spring Creek
1997	15.946	8685	0.918	Subbituminous	Absaloka/Spring Creek
1998	16.186	8728	0.927	Subbituminous	Absaloka/Spring Creek
1999	16.244	8642	0.940	Subbituminous	Absaloka/Spring Creek
2000	17.349	8456	1.026	Subbituminous	Cordero Complex/Coal Creek
2001	17.933	8425	1.064	Subbituminous	Cordero Complex
2002	22.748	8549	1.330	Subbituminous	Eagle Butte/Belle Ayr
2003	23.259	8551	1.360	Subbituminous	Eagle Butte/Belle Ayr
2004	24.095	8518	1.414	Subbituminous	Eagle Butte/Belle Ayr
2005	26.084	8687	1.501	Subbituminous	Cordero/Black Thunder
2006	25.882	8538	1.516	Subbituminous	Cordero/Black Thunder

Exhibit No. ___ (JTD-12)
1 page

Big Stone II Coal Projections

Year	BSP II $/ton	BSP II Btu/lb	BSP II $/MMBtu	% Change
2010	28.668	8400	1.706	
2011	29.055	8400	1.729	1.35%
2012	29.854	8400	1.777	2.78%
2013	30.449	8400	1.812	1.97%
2014	31.286	8400	1.862	2.76%
2015	32.722	8400	1.948	4.62%
2016	33.578	8400	1.999	2.62%
2017	34.463	8400	2.051	2.60%
2018	35.487	8400	2.112	2.97%
2019	36.948	8400	2.199	4.12%
2020	38.083	8400	2.267	3.09%
2021	39.266	8400	2.337	3.09%
2022	40.371	8400	2.403	2.82%
2023	41.508	8400	2.471	2.83%
2024	42.678	8400	2.54	2.79%
2025	43.882	8400	2.612	2.83%

Exhibit No. ___ (JTD-13)
1 page

Big Stone II Coal Projections

Year	BSP II $/ton	BSP II Btu/lb	BSP II $/MMBtu	% Change	* BSP II $/MMBtu	Difference from Projection
2010	28.668	8400	1.706		1.706	0
2011	29.055	8400	1.729	1.35%	1.755	0.026
2012	29.854	8400	1.777	2.78%	1.806	0.029
2013	30.449	8400	1.812	1.97%	1.859	0.047
2014	31.286	8400	1.862	2.76%	1.913	0.051
2015	32.722	8400	1.948	4.62%	1.968	0.020
2016	33.578	8400	1.999	2.62%	2.025	0.026
2017	34.463	8400	2.051	2.60%	2.084	0.033
2018	35.487	8400	2.112	2.97%	2.144	0.032
2019	36.948	8400	2.199	4.12%	2.207	0.008
2020	38.083	8400	2.267	3.09%	2.271	0.004
2021	39.266	8400	2.337	3.09%	2.336	-0.001
2022	40.371	8400	2.403	2.82%	2.404	0.001
2023	41.508	8400	2.471	2.83%	2.474	0.003
2024	42.678	8400	2.540	2.79%	2.546	0.006
2025	43.882	8400	2.612	2.83%	2.619	0.007

* at constant 2.9% escalation

Exhibit No.___ (JTD-14)
1 page

Carrying Costs on Additional Coal Inventory
at Big Stone II

2.5	million tons/year
÷ 365	days/year
6,849	tons/day
x 15	days additional inventory
102,740	tons of additional inventory
x $30	/ton cost of coal
$3.082	million of additional inventory
x 19.33%	ownership share
$595,800	cost of inventory for MDU/Otter Tail
x 11.25%	rate of return (plus income taxes)*
$67,028	carrying costs

* assumes: 7.5% cost of debt
12.0% cost of equity
50% equity/50% debt
40% tax rate