APPLICANTS' EXHIBIT 23

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

CASE NO. EL05-022

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER COMPANY

ON BEHALF OF THE BIG STONE II CO-OWNERS

FOR AN ENERGY CONVERSION FACILITY SITING PERMIT FOR THE

CONSTRUCTION OF THE BIG STONE II PROJECT

DIRECT TESTIMONY

OF

JEFFREY J. GREIG

GENERAL MANAGER OF THE BUSINESS & TECHNOLOGY SERVICES DIVISION

BURNS & McDONNELL ENGINEERING COMPANY

MARCH 15, 2006

TESTIMONY OF JEFFREY J. GREIG

TABLE OF CONTENTS

BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY OF JEFFREY J. GREIG

I. INTRODUCTION

Q: Please state your name and business address.

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

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

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

Q: What are your responsibilities in your current position?

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

Q: What is your educational background?

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

Q: What is your employment history?

A: I have 19 years of experience as a consultant in the electric power industry. My background includes generation resource planning, feasibility studies, siting studies, market assessments, project development, and asset due diligence.

Q: Have you previously provided testimony before the South Dakota Public Utilities Commission or other regulatory agencies?

A: I have not appeared before the South Dakota PUC. I have provided written and oral testimony before the Wisconsin Public Service Commission regarding a site certificate for a gas-fired project. I have provided written and oral testimony before the Ohio Power Siting Board regarding a site certificate for a gas-fired project. I have prepared written testimony regarding a site certificate and rate principles filing presented to the Iowa Utilities Board. I have prepared written testimony regarding power supply planning for the New Mexico Public Regulation Commission. I have prepared written testimony regarding a generation asset transfer for the Illinois Commerce Commission, and I have provided written and oral testimony regarding a generation asset transfer for the Federal Energy Regulatory Commission (FERC).

II. PHASE I REPORT

Q: What is the Phase I Report?

A: The Phase I Report is a report finalized by Burns & McDonnell in July 2005 entitled "Phase I Report Big Stone Unit II." A copy is attached to the testimony of Stephen Gosoroski as Applicants' Exhibit 24-A. The existing Big Stone station in South Dakota is a nominal 450-megawatt (MW) coal-fired generating plant owned by Otter Tail Power Company, Northwestern Energy (formerly Northwestern Public Service Company), and Montana-Dakota Utilities. These owners and other utility companies undertook a screening analysis of potential generation alternatives that is outlined in the testimony of Mr. Mark Rolfes of Otter Tail Power Company. Following and as part of the overall screening analysis, Burns & McDonnell was engaged to prepare the Phase I Report on Big Stone Unit II.

Q: What is the objective of the Phase I Report?

A: The objective of the Phase I Report was to evaluate the feasibility of adding an additional generation unit (Unit II) to the existing Big Stone station site from both quantitative and qualitative perspectives. The Phase I Report developed comparative capital costs, operating costs, performance, and emissions characteristics of different generation alternatives for the existing Big Stone site. The Phase I Report also included a quantitative economic evaluation of the life-cycle capital and operating costs of the different generation alternatives.

Q: What were your responsibilities for the Phase I Report on Big Stone Unit II completed by Burns & McDonnell in July 2005?

A: I managed the economic pro forma analysis of the generation alternatives. As such, I was responsible for the overall quality of the economic evaluation completed by a staff engineer in my group.

Q: What generation alternatives were considered in the economic evaluation of the Phase I Report on Big Stone Unit II?

A: Seven generation alternatives were evaluated in the economic analysis: (1) 600 MW supercritical PC unit; (2) 450 MW supercritical PC unit; (3) 300 MW subcritical PC unit; (4) 600 MW subcritical circulating fluidized bed (CFB) unit; (5) 450 MW subcritical CFB unit; (6) 300 MW subcritical CFB unit; and (7) 500 MW Combined Cycle Gas Turbine (CCGT) unit.

Q: What was the conclusion of the Phase I Report on Big Stone Unit II?

A: The Phase I Report concluded that a 600 MW supercritical pulverized coal (PC) plant represented the lowest cost generation alternative of the technologies evaluated for the Big Stone station site on a life-cycle basis considering capital and operating costs.

Q: Describe the process Burns & McDonnell used to develop the economic evaluation in the Phase I Report .

A: First, the capital cost, performance, and O&M cost estimates for the different generation alternatives are developed. In the Direct Testimony of Mr. Stephen Gosoroski of Burns & McDonnell, he testifies to the effort conducted by the Development Engineering group to develop these estimates. These estimates are used as the key inputs into a pro forma economic model that determines the annual busbar cost of power for each alternative on a revenue requirements basis over a 20-year planning period. Busbar refers to the cost of power without transmission, distribution, and ancillary service charges. Effectively the busbar cost is the cost of the power at the plant substation. The technical inputs were combined with economic, financing, and fuel cost assumptions to develop the overall busbar power costs. Two different economic models were prepared to reflect the different potential ownership structures.

Q: Why do you use a 20-year planning period ?

A: In my experience, a 20-year planning period is adequate to capture the life cycle cost performance of generation resource alternatives. The plants themselves will have a useful life that exceeds 20 years, but the relative economics between the alternatives will be demonstrated over the first 20 years of an economic evaluation. In the later years, the annual fuel and operating costs will continue to escalate, but generally in similar fashion. The latter year costs are significantly discounted and do not change the results of the analysis.

Q: Explain the need to prepare two pro forma models for different ownership structures.

A: Two different economic models were prepared to reflect the different potential ownership structures of public power (i.e., municipal utilities such as Missouri River Energy Services and cooperatives such as Great River Energy) and investor-owned utilities (such as Otter Tail). These types of utilities generally use different financing structures and have different revenue requirements. The public power model was intended to capture economic results that would be expected for a cooperative, municipal utility, or joint action agency. The public power model assumed tax-exempt debt financing through bonds for 100% of the estimated total project costs. Also, no income tax liability was estimated. For the investor-owned model, a 50% debt/50% equity financing structure was assumed, and an income tax liability component was estimated. The revenue requirements of each ownership structure were also determined differently.

Q: Explain the term revenue requirements and the different assumptions for the two ownership structures.

A: Revenue requirements are the total costs that need to be recovered on an annual basis, both operating costs and capital costs. For the public power utility model, the annual revenue requirements are defined as fuel costs, fixed and variable O&M costs, and debt service costs of principal repayment and interest. The debt service costs are estimated based on the total cost of the generation alternative and the financing assumptions. For the investor-owned utility model, the capital cost component of revenue requirements are defined differently. The revenue requirements are defined as fuel costs, fixed and variable O&M costs, interest on debt, depreciation expense, return on invested equity, and a tax liability component.

Q: What were the specific financing assumptions used in the economic analysis?

A: The public power model assumed tax-exempt debt financing through bonds for 100% of the estimated total project costs. The bond term was assumed as 30 years with a 6.0% interest rate. For the investor-owned model, a 50% debt/50% equity financing structure was assumed. The bond term was assumed as 20 years with a 7.5% interest rate for the debt component. The return on equity was assumed to be 12.0%. These financing assumptions were used for each of the generation alternatives.

Q: What were the other key assumptions used in the economic analysis?

A: The generation alternatives were evaluated as potential baseload resources. Therefore, the economic model was based on a high availability and high capacity factor operations of 88%. Additional assumptions included general escalation rates for capital and operating costs of 2.5% annually, and an effective tax rate of 40% for the investor-owned utility model. The other important estimates were the fuel cost forecasts.

Q: What was the basis for the fuel cost forecasts used in the economic analysis?

A: All of the solid fuel generation alternatives used the same fuel – Powder River Basin (PRB) coal. The PRB fuel cost forecast was based on a review of delivered costs to the existing Big Stone station escalated by 2.0% annually. This resulted in an overall delivered cost estimate for PRB coal of $1.28/MMBtu in 2010. A natural gas combined cycle case was prepared as a benchmark comparison. The natural gas cost forecast was based on the February 2004 NYMEX futures price for Henry Hub natural gas commodity supply in 2009 of $4.61/MMBtu plus a transportation cost. The Department of Energy's *Annual Energy Outlook 2004* was used as the basis of real escalation adjustments for 2010 to 2025 with a nominal escalation rate of 2.0%. This resulted in an overall delivered cost estimate for natural gas of $5.10/MMBtu in 2010.

Q: Did the economic analysis include costs for emissions allowances?

A: Yes. The economic models assumed a cap-and-trade system or similar emissions reduction structure would be in place and emission allowances would be required for SO_2, NO_x and mercury emissions. The emission allowance costs for SO_2 were estimated as $700/ton through 2014, $1,109/ton thereafter. The emission allowance costs for NO_x were estimated as $1,300/ton through 2014, $1,507/ton thereafter. The emission allowance costs for mercury were estimated as $35,000/lb. These allowance costs were escalated similar to the O&M costs.

Q: What were the specific results of the economic analysis?

A: For the public power utility ownership model, the lowest cost generation alternative was the 600 MW supercritical PC unit with an estimated busbar cost of $38.26/MWh in 2010. This was followed by the 600 MW CFB unit ($40.21/MWh), the 450 MW PC unit ($41.28/MWh), and the 450 MW CFB unit ($43.95/MWh). The highest cost generation alternative was the 500 MW CCGT unit ($55.55/MWh). For the investor-owned utility ownership model, the lowest cost generation alternative was also the 600 MW supercritical PC unit with an estimated busbar cost of $47.05/MWh in 2010. This was followed by the 600 MW CFB unit ($49.37/MWh), the 450 MW PC unit ($51.18/MWh), and the 450 MW CFB unit ($54.53/MWh). The highest cost generation alternative was the 500 MW CCGT unit ($56.95/MWh).

The economic evaluation demonstrates that there is an economy of scale benefit within the coal-fired resource alternatives. The estimated busbar costs consistently declined for larger unit sizes, with 600 MW representing the lowest cost alternative evaluated. The economic evaluation demonstrates that the difference in costs between the pulverized coal and CFB technologies are not significant, but there is a cost advantage for the PC technology due to its lower capital cost and higher efficiency for PRB fuel. The economic evaluation also demonstrates that a coal-fired generation resource has a significant economic advantage compared to a high-efficiency natural gas CCGT unit for baseload capacity and energy requirements due to the fuel cost differentials between coal and natural gas.

Q: What other analyses were prepared in the Phase I Report?

A: We prepared different sensitivity analyses to evaluate the changes in results for changes in key inputs. We prepared sensitivity analyses for the following:

- Capital Cost plus or minus 10%
- Interest Rate plus or minus 1.0%
- Capacity Factor plus or minus 5%
- Fuel Cost plus or minus 20%
- O&M Costs plus or minus 10%

Q: What were the results of the sensitivity analyses?

A: For the investor-owned utility, the overall busbar cost for the coal-fired generation alternatives is most sensitive to capital cost and fuel cost. A ten percent increase in the capital cost of a 450 MW PC unit would increase the levelized busbar cost by $3.63/MWh. For the public power utility, the overall busbar cost for the coal-fired generation alternatives is most sensitive to interest rate and fuel cost. A one percent increase in the interest rate for financing a 450 MW PC unit would increase the levelized busbar cost by $3.44/MWh. For the gas-fired combined cycle unit, the overall busbar cost is most sensitive to fuel cost.

A separate capacity factor analysis was prepared to identify the cross-over point between the economics of a 450 MW PC unit and a 500 MW CCGT unit. For both the investor-owned utility ownership and public power utility ownership, a 450 MW PC unit represented a lower cost resource at the base case capacity factor assumption of 88%. The cross-over point at which the busbar costs would be equal between the two alternatives occurred at a 49% capacity factor for the public power utility model and a 71% capacity factor for an investor-owned utility model. At intermediate capacity factors below these values, the gas-fired CCGT resource would demonstrate an economic advantage.

Q: Explain the term levelized.

A: Generally, costs increase over time due to inflation impacts on operating costs and fuel costs. Over a long-term year planning period, a levelized busbar cost represents a single, all-in power cost that captures measures of both cost escalation and the time value of money. For the selected discount rate, the owner would be indifferent to the levelized busbar cost throughout the planning period or a power cost that started lower but escalated annually. A levelized busbar cost is a useful summary measure for comparing alternatives.

III. ANALYSIS OF BASELOAD GENERATION ALTERNATIVES

Q: Did Burns & McDonnell prepare any additional studies to evaluate the economics of different generation alternatives?

A: Yes. Subsequent to the Phase I Report on Big Stone Unit II, Burns & McDonnell prepared a study titled, "Analysis of Baseload Generation Alternatives – Big Stone Unit II" dated September 2005. This study and report is included as Applicants' Exhibit 23-A.

Q: What was the purpose of the Generation Alternatives Study?

A: The construction and operation of Big Stone Unit II will necessitate the construction of new transmission lines in Minnesota (and South Dakota) to reliably deliver the output to the loads of some of the participating utilities. A Certificate of Need (CON) is required in Minnesota for a new Large High Voltage Transmission Line (LHVTL) pursuant to Minnesota Statutes, Chapter 216B. The Generation Alternatives Study was prepared in connection with the Minnesota CON. The objectives were similar to the Phase I Report but considered an expanded set of generation alternatives. The Generation Alternatives Study evaluated comparative capital costs, operating costs, performance, emissions characteristics, and economics of different baseload generation technologies. However, unlike the Phase I Report, the new analysis was not limited to generation alternatives located at the Big Stone site but was instead designed to provide a broader overview of generation alternatives for meeting the Applicants' needs for 600 MW of baseload power.

Q: What were your responsibilities for the Generation Alternatives Study?

A: I was the overall project manager for the study, and I managed the economic pro forma analysis of the generation alternatives.

Q: What alternatives were considered in the Generation Alternatives Study?

A: Six alternative baseload power plant technologies were evaluated. From the Phase I Report on Big Stone Unit II, the low cost alternative of a 600 MW supercritical PC unit was carried forward. The five other generation technologies included: (1) 600 MW subcritical PC unit, (2) 600 MW CCGT unit, (3) 535 MW IGCC unit, (4) 50 MW 100% Biomass unit, and (5) 600 MW CCGT unit plus Wind.

Q: What was the conclusion of the Generation Alternatives Study?

A: This second study reconfirmed that a 600 MW PC plant represents the lowest cost generation alternative of the baseload technologies evaluated on a life-cycle basis considering capital and operating costs. The overall economic difference between subcritical and supercritical PC technology was not material. The supercritical technology has been selected for Big Stone Unit II to minimize emissions.

Q: Did you include any sensitivities with respect to a possible carbon tax in the Generation Alternatives Study?

A: Yes. The Generation Alternatives Study also included a carbon tax sensitivity. The study assumed a carbon tax of $3.64/ton of CO_2 added to all of the generation alternatives. This figure is the high end externality value used by the Minnesota Public Utilities Commission to monetize CO_2 emissions from generating stations located in Minnesota. The Minnesota Commission does not apply a CO_2 externality value for generation located outside of Minnesota, and South Dakota does not apply externality values in resource decisions. Nevertheless, even applying the $3.64/ton value, the economic conclusion that a 600 MW PC plant represents the lowest cost generation alternative of the baseload technologies evaluated was confirmed.

Q: Was the process Burns & McDonnell used to develop the economic evaluation in the Generation Alternatives Study the same as it was in the Phase I Report?

A: Yes. First, the capital cost, performance, and O&M cost estimates for the different generation alternatives were developed by Burns & McDonnell's Development Engineering Group. These estimates were used as the key inputs into a pro forma economic model that determined the annual busbar cost of power for each alternative on a revenue requirements basis over a 20-year planning period.

Q: Were the financing assumptions for the two different ownership structures the same in the Generation Alternatives Study as they were in the Phase I Report?

A: Yes.

Q: Were the other key operating and economic assumptions the same in the Generation Alternatives Study as they were in the Phase I Report?

A: Yes.

Q: What was the basis for the fuel cost forecasts used in the Generation Alternatives Study?

A: The PRB fuel cost forecast for the 600 MW supercritical PC unit and 600 MW subcritical PC unit was based on a review of delivered costs to the existing Big Stone station escalated by 2.0% annually. This resulted in an overall delivered cost estimate for PRB coal of $1.21/MMBtu in 2007. For the IGCC alternative, it was assumed that an Illinois Basin bituminous coal would be the feedstock. Based on current market pricing for this commodity, an overall delivered cost estimate of $2.47/MMBtu in 2007 was used. In September 2005, the NYMEX futures price for Henry Hub natural gas commodity supply in 2010 was $7.45/MMBtu. A transportation cost would have to be added to this supply cost. However, the U.S. was experiencing record natural gas prices over $12.00/MMBtu in the aftermath of the hurricanes that struck the Gulf Coast region. Therefore, a more conservative assumption was used in the study based on a delivered cost of $7.00/MMBtu for 2011 and a 2.5% escalation rate. For the biomass alternative, Burns & McDonnell estimated a delivered cost of $5.98/MMBtu for a dedicated wood crop such as hybrid poplar.

Q: What was the basis for the cost of wind resources used in the Generation Alternatives Study?

A: For the Wind plus CCGT alternative, it was assumed that the wind component would be purchased from independent power developers at a levelized cost of \$50/MWh for a 2011 in-service date. The current Renewable Energy Production Tax Credit (PTC) of 1.9 cents/kWh expires in 2007 and may not be available as a subsidy to lower the cost of wind energy.

Q: Did you include costs for emissions allowances in the Generation Alternatives Study?

A: Yes. The economic models assumed emission allowances would be required for SO_2, NO_x and mercury emissions. The emission allowance costs for SO_2 were estimated as \$700/ton. The emission allowance costs for NO_x were estimated as \$1,300/ton during the ozone season. The emission allowance costs for mercury were estimated as \$35,000/lb. These allowance costs were escalated annually.

In addition, as mentioned, the Generation Alternatives Study included a separate carbon tax scenario. For each of the baseload generation alternatives, an assumed carbon tax of \$3.64/ton of CO_2 was included in a sensitivity analysis.

Q: Are CO_2 emissions currently subject to a carbon tax in the US?

A: No. There is no CO_2 or carbon tax in the US.

Q: What are the respective CO_2 emissions of the generation alternatives?

A: Coal is the most carbon intensive fuel at 208 lbs/MMBtu, but all fossil fuels release CO_2 when combusted. Natural gas for the CCGT case releases approximately 110 lbs/MMBtu. Wind has no carbon dioxide emissions, so a blended Wind plus CCGT case will have less emissions. The combustion of biomass feedstock releases CO_2, but it is assumed to be equal to the uptake of CO_2 in a closed-loop biomass system for a net emissions rate of zero. For the IGCC facility based on bituminous coal, a CO_2 emissions rate of 200 lbs/MMBtu was used.

Q: Is IGCC promoted as a technology to minimize CO_2 emissions?

A: Yes, but only if CO_2 is captured and sequestered. Neither of the two operating IGCC plants in the U.S. capture CO_2 and most of the proposed IGCC facilities in development do not plan to initially capture or sequester CO_2. Without the capture of CO_2, the carbon emissions from an IGCC facility are similar to a supercritical PC unit. Because IGCC technology creates a syngas, there is a technological capability of scrubbing CO_2 from the syngas, and this capability is enhanced if an oxygen-blown gasifier is used and a more concentrated steam is created. However, CO_2 capture adds significant costs and technical challenges to an IGCC plant, since the technology has not been commercially demonstrated.

Q: What were the specific results of the economic evaluation developed in the Generation Alternatives Study?

A: For the public power utility ownership model, the lowest cost generation alternative was the 600 MW subcritical PC unit with an estimated levelized busbar cost of $47.21/MWh over the 2011 to 2030 planning period. This was closely followed by the 600 MW supercritical unit at $47.37/MWh. The 600 MW Wind plus CCGT alternative was next at $70.57/MWh, which is 49% higher than the 600 MW supercritical PC unit. The 535 MW IGCC unit ($71.05/MWh), the 600 MW CCGT unit ($75.61/MWh), and the 50 MW biomass unit ($156.02/MWh) all resulted in higher costs. For the investor-owned utility ownership model, the lowest cost generation alternative was also the 600 MW subcritical PC unit with an estimated levelized busbar cost of $58.41/MWh over the 2011 to 2030 planning period. This was closely followed by the 600 MW supercritical unit at $58.81/MWh. The 600 MW Wind plus CCGT alternative was next at $72.89/MWh, which is 24% higher than the 600 MW supercritical PC unit. The 600 MW CCGT unit ($77.94/MWh), the 535 MW IGCC unit ($83.84/MWh), and the 50 MW biomass unit ($170.52/MWh) all resulted in higher costs.

The economic evaluation demonstrates that a coal-fired generation resource has a significant economic advantage compared to a natural gas CCGT unit or a wind plus CCGT alternative due to the fuel cost differentials between coal and natural gas. The overall economic difference between subcritical and supercritical PC technology at 600 MW was not material. IGCC technology was not competitive on an economic comparison with the PC technology. The supercritical technology has been selected for Big Stone Unit II to minimize emissions.

Q: What were the specific results of the carbon economic evaluation developed in the Generation Alternatives Study?

A: The conclusions did not change when an assumed carbon tax of $3.64/ton of CO_2 was added. For the public power utility ownership model, the levelized busbar cost of the 600 MW supercritical PC unit increased to $52.22/MWh. The 600 MW Wind plus CCGT alternative was $71.77/MWh, a difference of 37%. For the investor-owned utility ownership model, the levelized busbar cost of the 600 MW supercritical PC unit increased to $63.69/MWh. The 600 MW Wind plus CCGT alternative was $74.08/MWh, a difference of 16%.

For the public power utility ownership model, a carbon tax of $23.00/ton would be required to equalize the levelized busbar cost of the 600 MW supercritical PC unit with the Wind plus CCGT alternative at a cost of approximately $78/MWh. This represents an increase of 65 percent compared to the base case cost of $47.37/MWh for the 600 MW supercritical PC unit alternative. For the investor-owned utility ownership model, a carbon tax of $14.00/ton would be required to equalize the levelized busbar cost of the 600 MW supercritical PC unit with the

Wind plus CCGT alternative at a cost of approximately $77/MWh. This represents an increase of 31 percent compared to the base case cost of $58.81/MWh for the 600 MW supercritical PC unit alternative.

Q: What conclusion did you reach on the basis of the economic analysis performed?

A: The economic analyses prepared for the Phase I Report and the subsequent Generation Alternatives Study demonstrate that the 600 MW supercritical PC plant is a least-cost generation alternative for the Big Stone station site on a life-cycle basis considering capital and operating costs compared to numerous other generation alternatives.

Q: Does this conclude your testimony?

A: Yes.