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

STEPHEN J. GOSOROSKI, P.E.

PROJECT MANAGER

BURNS & MCDONNELL ENGINEERING COMPANY

MARCH 15, 2006

BIG STONE II
PARTNERS IN GENERATION

TESTIMONY OF STEPHEN J. GOSOROSKI, P.E.

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BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY OF STEPHEN J. GOSOROSKI, P.E.

I. INTRODUCTION

Q: Please state your name and business address.

A: Stephen (Steve) J. Gosoroski, P.E., Burns & McDonnell Engineering Company, 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 Co. Currently, I am a Project Manager for the company's Energy Division.

Q: What are your responsibilities in your current position?

A: I am responsible for overseeing the design and engineering execution of projects where I am assigned as the Project Manager.

Q: What is your educational background?

A: I have a Bachelors Degree in Mechanical Engineering from the University of Missouri-Columbia, and an MBA Degree from the University of Missouri-Kansas City. I am a Professional Engineer with 29 years of experience as an engineering consultant with Burns & McDonnell.

Q: What is your employment history?

A: I was a design engineer in the Mechanical Department of the Energy Division for ten years and worked on the design of several coal fired plants during that time. I served as Assistant Project Manager for a period of five years before becoming the Project Manager, and have served in the role of Project Manager for a period of fourteen years on several coal and natural gas projects for the Energy Division.

II. PHASE I REPORT

Q: What is the Phase I Report?

A: The Phase I Report is a report prepared by Burns & McDonnell in July 2005 entitiled "Phase I Report Big Stone Unit II." 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 screening analysis, Burns & McDonnell was engaged to prepare the Phase I Report on Big Stone Unit II.

The Phase I Report provided a conceptual basis for estimating costs of different generation alternatives that were evaluated in an economic analysis. The Burns & McDonnell Phase I Report on Big Stone Unit II dated July 2005 is included as Applicants' Exhibit 24-A.

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 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 was the Project Manager for the Phase I Report. As such, I was responsible for the overall report preparation.

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

A: Initially, nine generation alternatives were identified: (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, (7) 500 MW Combined Cycle Gas Turbine (CCGT) unit, (8) 550 MW Integrated Gasification Combined Cycle (IGCC) unit, and (9) 250 MW wind turbines. The IGCC alternative and wind alternative were considered initially, but were not recommended based on an initial technology assessment of these alternatives. The remaining seven generation alternatives were evaluated in more detail in the Phase I Report.

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: Why was wind not included in this Phase I study?

A: The Phase I Report noted that wind is among the most common and economically viable renewable resource technologies employed in the Upper Midwest region. However, the Phase I Report was limited to generation alternatives that could provide firm baseload capacity and energy, and could be located at the Big Stone station. Wind resources did not meet either criterion for purposes of this study. Wind resources are not dispatchable and do not have expected capacity factors that are reliable to meet baseload energy requirements. In addition, installation of wind turbines at the Big Stone station would not take advantage of existing infrastructure at the site. The existing investment in the site would not be optimized with the installation of wind turbines at this location.

Q: Why was IGCC not included in this Phase I Report?

A: IGCC is a developing technology in the power generation industry. While coal gasification in the chemical or process industry is established, the recent history of coal gasification integrated with combustion turbine and combined cycle technology in the US has experienced technical and operating reliability issues. There were five IGCC demonstration projects developed in the US with Department of Energy (DOE) funding assistance in the 1980's and 1990's. Today, only two of those facilities remain in operation. Availability and reliability of these existing IGCC facilities have improved in recent years after initial poor performance, and the next generation of IGCC plants is expected to incorporate design changes and redundancy to achieve higher availability and reliability performance. There are several proposed IGCC facilities in development and the major technology suppliers are investing resources to bring the next generation of the technology to the marketplace. Burns & McDonnell is currently engaged as the design engineer on one of the proposed IGCC facilities. However, at this time, IGCC technology is not commercially proven.

A second important factor is the fuel feedstock for IGCC. Neither of the current operating IGCC facilities in the US utilizes subbituminous coal from the Powder River Basin

(PRB). PRB coal is the fuel used at the Big Stone station and is the preferred fuel for any new coal-fired resource located at the site. The majority of current IGCC facilities in development are planning on the use of bituminous coals. Research is continuing into the use of PRB fuel in gasification applications. Southern Company, for instance, one of the country's largest utilities, recently secured DOE funding for an IGCC demonstration project using PRB fuel in a new gasification technology.

Finally, Burns & McDonnell estimated in the Phase I Report that IGCC has a cost premium of 10 to 15 percent compared to a similar size pulverized coal unit, and no schedule advantage compared to proven coal generation technologies. The permitting and construction timeframes are similar. Overall, IGCC technology was not recommended in the Phase I Report due to its lack of commercial development at this time, lack of demonstrated ability to utilize PRB fuel, and cost premium compared to proven technologies.

Q: Explain the basic difference between supercritical and subcritical plants?

A: Subcritical power plants utilize pressures below the critical point of water. The critical point of water, the point at which there is no difference in the density of water and steam, occurs at 3,208 psi and 704.5 ˚F. The majority of the steam generators built in the US utilize subcritical technology with operating pressure of 2400 to 2520 psig. The existing 450 MW Big Stone station is a subcritical unit. Supercritical units typically operate at 3500 to 3700 psig with main and reheat steam temperatures of 1000°F or greater. Recent supercritical units under design in the US use main steam temperatures between 1050°F and 1075°F and reheat steam temperatures between 1050°F and 1100°F. The economic tradeoff between the technologies is efficiency and capital cost. A supercritical unit will be 3 to 4 percent more efficient than a similar subcritical unit. This results in less fuel costs and less emissions. The capital cost of a supercritical unit will be more than a subcritical unit by a similar percentage due to higher alloy material costs. Both subcritical and supercritical technologies were considered in the Phase I study.

Q: Explain the basic difference between PC and CFB technology?

A: Within a pulverized coal plant (PC), the coal is crushed and further pulverized in mills to a fine powder. It is blown into the furnace with hot air and is combusted in a suspended fireball. The heat generated converts water in the boiler tubes that make up the furnace walls into steam. Most of the coal ash is carried out of the furnace in the exiting flue gas and this fly ash is removed downstream by particulate removal systems such as a baghouse. A smaller portion of the heavier ash particles falls to the bottom of the boiler and is removed as bottom ash.

CFB boilers are a newer technology. Within a circulating fluidized bed boiler, the coal is crushed, but not pulverized. The coal is fed into the furnace where it is combusted on a bed of fuel and limestone that is suspended with upward-blowing air. The limestone is incorporated in the fluidized combustion bed to reduce the formation of sulfur dioxides during the combustion process instead of downstream removal from the flue gas. Bed material and ash that is carried out of the furnace is separated from the flue gas with refractory-line cyclones and recirculated back into the furnace. The heat in the flue gas converts water into steam in a heat exchanger section of the boiler. Most of the ash in this technology is bottom ash that is removed from the boiler.

Q: Explain the different advantages of each technology.

A: The primary benefits of the CFB technology relative to the PC technology are the ability to effectively handle a wider range of fuels and lower emissions exiting the boiler itself. The formation of sulfur dioxides in the furnace is lower due to the addition of limestone in the combustion process, and the formation of nitrous oxides is lower due to lower combustion temperatures. For the PC technology, these emissions must be reduced through back-end control technologies. The primary benefits of the PC technology to the CFB technology are better efficiency due to lower auxiliary loads and lower capital costs. Also, the CFB technology is currently limited to a boiler size of 250 to 300 MW. Plant sizes above this range must incorporate two boilers at a cost disadvantage to a single, larger PC boiler. Both PC and CFB technologies were considered in the Phase I Report.

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

A: The first step was to define the scope and technical basis of each generation alternative. Attachment A in the Phase I Report outlines the equipment and system descriptions that comprise each technology. Additional major factors that drive the technical development of each generation alternative include the site, fuel supply, water supply, and environmental requirements.

III. SITE FACTORS

Q: How did site factors influence the cost and performance estimates of the generation alternatives?

A: One of the important benefits of the Big Stone site is that it is an existing coal-fired generation site. There are significant infrastructure savings that can accrue to an additional unit added at an existing "brownfield" location compared to a new "greenfield" project. Access to existing infrastructure for fuel delivery and unloading, fuel storage and handling, water supply and storage, ash storage and disposal, warehousing, administrative facilities, and close proximity to transmission facilities are all areas that were reviewed during the development of the capital cost estimates. In addition, staffing costs for any new generation resource will be lower at an existing location since only incremental staff needs to be added for operation and maintenance of an additional unit. This factor was also incorporated in the development of the operation and maintenance (O&M) cost estimates.

Q: How did fuel supply influence the cost and performance estimates of the generation alternatives?

A: The fuel choice impacts the capital and operating cost estimates of the solid fuel generation alternatives in three areas. First, the fuel handling equipment, boiler design, and ash handling/disposal are influenced by fuel characteristics which are incorporated into the capital cost estimates, performance estimates, and O&M estimates. Second, the fuel characteristics and boiler design influence the air quality control systems that are needed to meet environmental requirements. Finally, fuel costs are the largest single ongoing operating expense for the plant and delivered fuel cost estimates are incorporated into the economic analysis. For the solid fuel generation alternatives, PRB coal was the selected fuel. PRB coal is the fuel used at the existing Big Stone station, is a low sulfur coal, and has the lowest expected delivered cost of solid fuel alternatives for the Big Stone location. The capital cost, performance and O&M estimates were based on the use of PRB coal for the solid fuel generation alternatives. For the gas fired alternative, natural gas quality does not vary significantly. The primary impact is the ongoing fuel purchase costs which were modeled in the economic analysis.

Q: How did water supply influence the cost and performance estimates of the generation alternatives?

A: As noted, the existing Big Stone site has existing water supply and storage infrastructure. A primary effort of the Phase I Report on Big Stone Unit II was to evaluate how to integrate a new generation resource within the water supply, storage, quality, treatment, and disposal parameters of the existing site. There is also an existing ethanol facility off-site that is supplied with water from the site. The recommendation for Big Stone Unit II was to utilize a wet cooling tower for heat rejection of the new unit. The capital costs, performance, and O&M cost estimates for the generation alternatives were based on this recommendation.

Q: How did environmental factors influence the cost and performance estimates of the generation alternatives?

A: The air quality control systems planned in the Phase I Report for each of the generation alternatives was estimated based on expected Best Available Control Technology (BACT) requirements to secure an environmental permit for a new resource. For the PC unit alternatives, the cost and performance estimates were based on the use of a Selective Catalytic Reduction (SCR) system to achieve a NO_x emissions rate of 0.07 lb/MMBtu, a dry Flue Gas Desulfurization (FGD) system to achieve an SO_2 emissions rate of 0.12 lb/MMBtu, and a baghouse to achieve particulate emissions of 0.018 lb/MMBtu. Carbon monoxide (CO) would be controlled through good combustion practices. For mercury control, an activated carbon injection system would result in estimated emissions of 0.00002 lb/MWh.

For the CFB unit alternatives, the cost and performance estimates were based on the use of a Selective Non-Catalytic Reduction (SNCR) system to achieve a NO_x emissions rate of 0.08 lb/MMBtu, limestone injection and ash re-injection to the boiler to achieve an SO_2 emissions rate of 0.12 lb/MMBtu, and a baghouse to achieve particulate emissions of 0.018 lb/MMBtu. For mercury control, an activated carbon injection system would result in estimated emissions of 0.00002 lb/MWh. CO would be controlled through good combustion practices.

For the natural gas combined cycle unit, dry low-NO_x burners and an SCR system would be utilized to achieve a NO_x emissions rate of three parts per million, and a CO catalyst would achieve the same emissions rate of CO from the unit. The capital costs, performance, and O&M cost estimates for the generation alternatives were based on the installation of these control technologies.

IV. CAPITAL COST ESTIMATES

Q: Describe how the capital cost estimates in Section 6 of the Phase I Report on Big Stone Unit II were developed.

A: Once the conceptual design basis for each generation alternative was developed, the next step was to prepare the capital cost, performance, and O&M estimates. For the capital cost estimates, Burns & McDonnell uses cost data available from similar projects that we maintain in internal, proprietary databases. The cost of other projects is adjusted to reflect changes in the scope of the project such as the issues discussed regarding site, fuel supply, water supply, and environmental requirements. Other adjustments are made to reflect regional location for labor and material costing, schedule, market conditions, and contracting approach.

To ensure consistency and quality of the different cost estimate we prepare, Burns & McDonnell maintains a full-time Development Engineering department within the Energy Division. This group is responsible for all power generation cost estimates, whether planning level estimates used in feasibility studies such as the Phase I Report or detailed cost estimates used to support bids submitted by Burns & McDonnell on the design and construction of a power plant.

Q: Is Burns & McDonnell active in the design and construction of new coal plants upon which to base the capital cost estimates?

A: Yes. For CFB units, Burns & McDonnell was the owner's engineer for two of the most recent CFB projects completed in the US - the 440 MW Red Hills project owned by Tractebel in Mississippi and the 500 MW Seward project owned by Reliant Energy in Pennsylvania. For PC units, Burns & McDonnell was the design engineer for the rebuild of the 550 MW Hawthorn Station owned by Kansas City Power & Light in Missouri, and we are currently the owner's engineer for the 790 MW supercritical PC unit under construction at the Council Bluffs Station in Iowa for MidAmerican Energy. These are just a few examples of coal-fired projects that Burns & McDonnell has actual capital cost data. In the last five years, we have completed over 30 technology assessments and capital cost estimates on various proposed coal units across the country.

Q: Describe how the performance and O&M cost estimates were developed for Phase I Report on Big Stone Unit II.

A: The performance and O&M cost estimates also reflect the conceptual design basis for each generation alternative. Similar to the capital cost estimates, the performance estimates are based on actual performance information from similar units adjusted for site conditions and the scope of the project. In addition, Burns & McDonnell works with the major equipment manufacturers to evaluate the technical performance and specifications of their current designs for boilers, steam turbines, air quality control systems, and other equipment. O&M cost estimates are prepared under a similar approach. The actual operating cost experience is adjusted for known scope and site changes. For a brownfield expansion such as the Big Stone Unit II, costs for the existing station are reviewed and estimates are developed based on incremental staffing and O&M requirements of each generation alternative.

Q: Do the performance estimates include emissions?

A: Yes, the emissions performance of the proposed air quality control systems is estimated based on actual operating experience with similar applications on similar fuel and the performance guarantees that the manufacturers are willing to provide on the systems.

Q: What type of contingency or margin is included in the capital cost estimates?

A: The capital cost estimates developed for the Phase I Report included an eight percent contingency factor for the coal alternatives and approximately 7.75% for the natural gas combined cycle alternative. In addition, sensitivity analyses were prepared in the economic evaluation with an additional plus or minus ten percent estimate.

V. ANALYSIS OF BASELOAD GENERATION ALTERNATIVES

Q: Did Burns & McDonnell prepare any additional studies to evaluate 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, attached as part of Mr. Jeff Greig's Direct Testimony.

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 CON application. The objectives were similar to the Phase I Report, but the Generation Alternatives Study was not limited to generation that could be constructed at the Big Stone site and included 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.

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

A: I was the Project Manager.

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 for the Big Stone station site 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: Why weren't the 250 MW and 450 MW baseload coal technologies evaluated again in the Generation Alternatives Study?

A: The Phase I Report demonstrated that the larger 600 MW alternatives resulted in lower overall economic costs due to economy of scale. There was also additional interest in new baseload resources from potential participants in the Big Stone Unit II project that increased the total need beyond the smaller plant size levels. In the second study, the smaller unit sizes were not included.

Q: Why wasn't the CFB coal technology evaluated again in the Generation Alternatives Study?

A: The Phase I Report demonstrated that PC unit technology represented an economic advantage due to lower capital cost and higher efficiency, particularly at the 600 MW size range. In the second study, CFB technology was not included.

Q: The Phase I Report did not recommend IGCC for Big Stone Unit II. Why was IGCC included in the second study, the Generation Alternatives Study?

A: In the Phase I Report, IGCC technology was not recommended due to three factors: (1) its lack of commercial development; (2) lack of demonstrated ability to utilize PRB fuel; and (3) cost premium compared to proven technologies such as PC and CFB plants. As a result, IGCC was not included in the economic evaluation prepared for the Phase I Report. In the second study, an IGCC concept was developed that might address the three factors sited above so that an economic analysis could be prepared comparing a realistic IGCC alternative with the other generation alternatives.

Q: Explain the IGCC concept included in the Generation Alternatives Study.

A: First, the capital cost estimate developed for the IGCC alternative includes the cost to install a spare gasification train. This would be expected to mitigate some of the operational and availability risk. Second, to mitigate the technological risk associated with the use of PRB fuel, the capital and operating cost estimates developed for the IGCC alternative are based on the use of bituminous coal, which is being used at the two IGCC facilities that are currently operating in the US. Since the cost to deliver bituminous coal to the Big Stone site would be prohibitive, the IGCC facility was assumed to be developed and constructed at a generic, off-site location that would have access to fuel, water and transmission facilities.

Q: Explain the 600 MW CCGT alternative included in the Generation Alternatives Study compared to the 500 MW CCGT alternative included in the Phase I Report.

A: In the Phase I Report, different coal generation alternatives including 450 MW and 600 MW sizes were considered. Therefore, a 500 MW CCGT facility was consistent with these alternatives. In the Generation Alternatives Study, a 600 MW CCGT was selected to be the same size as the 600 MW supercritical PC unit. With supplemental firing of the heat recovery steam generator in a combined-cycle plant, 600 MW of output is achievable. All capital and operating costs are evaluated on an overall dollar per megawatt-hour ($/MWh) basis, so differences in installed capacity do not bias the results, but similar sizes were used when applicable.

Q: Explain why the IGCC alternative is 535 MW instead of 600 MW.

A: An IGCC facility will have higher auxiliary power loads consumed by the plant than a PC unit or CCGT unit for equipment such as the air separation unit. The installed capacity values used in the evaluation represent net capacity. The 535 MW of net output for the IGCC facility is a standard size being considered in development. As discussed, all capital and operating costs are evaluated on an overall dollar per megawatt-hour ($/MWh) basis, so differences in installed capacity do not bias the results.

Q: Explain why the 100% Biomass plant alternative is 50 MW.

A: For this alternative, it simply is not viable to develop a 500 MW or larger biomass facility. Existing wood-fired biomass plants are in the range of 50 MW or smaller. Significant quantities of biomass material are required to meet the heat input requirements of even a small biomass facility. Burns & McDonnell estimated that over 600,000 acres of dedicated biomass crops would be required to support a 600 MW biomass facility.

For a 50 MW plant size, the capital costs of the biomass alternative will suffer from poor economies of scale compared to the larger generation alternatives. However, it was important to evaluate this technology as a viable concept, and not bias the results with a set of assumptions that are not possible.

Q: Explain the 600 MW Wind plus CCGT alternative.

A: As noted in the Phase I Report, wind resources are intermittent and are not dispatchable. Therefore, wind was not considered a technically viable alternative to meet baseload capacity and energy requirements in the Phase I Report. The 600 MW of wind plus CCGT alternative was developed in the Generation Alternatives Study to provide a combination of these two resources that would be firm. To the extent wind energy is available, the CCGT plant dispatch is decreased since it represents the higher cost energy resource. If little or no wind energy is available, the CCGT plant can be fully dispatched as a firm resource to meet baseload requirements.

Q: Why wasn't a simple cycle gas turbine (SCGT) used to backup the wind energy?

A: A simple cycle gas turbine project would represent a lower capital cost alternative to provide firm capacity for the intermittent wind energy. However, the wind resource is expected to yield an overall capacity factor of 40 percent if it was developed at a site with excellent wind resources. The dispatch required by the gas resource would then be at a capacity factor of 48 percent to achieve the high capacity factor achieved by the PC unit. With high gas prices, the higher efficiency of the CCGT plant will offset the lower capital cost of the SCGT plant and result in a net improvement in the economics of this alternative.

Q: The capital cost estimate for the 600 MW supercritical PC unit is different in the Generation Alternatives Study than the Phase I Report. Please explain.

A: The capital cost estimate in the Phase I Report for the 600 MW supercritical PC unit was estimated as $999,893,073, or $1,666/kW. The capital cost estimate in the Generation Alternatives Study for the 600 MW supercritical PC unit was $1,800/kW. There are two primary reasons for the estimated increase in costs between the two studies. First, the emission control technology for SO_2 assumed in the Phase I Report was a dry scrubber, and the second study assumes a higher efficiency, higher cost wet scrubber technology. Secondly, the capital costs of the proposed wet scrubber were increased to oversize the system to also control emissions from the existing Big Stone plant in a common scrubber with Big Stone Unit II. As a result of this common scrubber, SO_2 emissions from the site as a total with the addition of Unit II will be lower than existing emissions. This represents a significant environmental benefit.

Q: Was the same approach and diligence used in developing the capital cost, O&M cost and performance estimates in the Generation Alternatives Study as the Phase I Report?

A: Yes.

Q: Is Burns & McDonnell participating in the construction of the proposed Big Stone Unit II?

A: No. Another engineering firm is responsible for design of Big Stone Unit II.

Q: Does this conclude your testimony?

A: Yes.