APPLICANTS' EXHIBIT 2

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

RICHARD R. LANCASTER

VICE PRESIDENT, GENERATION

GREAT RIVER ENERGY

MARCH 15, 2006

TESTIMONY OF RICHARD R. LANCASTER

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BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
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I. INTRODUCTION

Q: Please state your name and business address.

A: Richard R. Lancaster, 17845 East Highway 10, Elk River, Minnesota, 55330-0800

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

A: Vice President, Generation, Great River Energy

Q: What is your educational background?

A: A curriculum vitae is attached as Applicants' Exhibit 2-A.

Q: What is your employment history?

A: A curriculum vitae is attached as Applicants' Exhibit 2-A.

Q: Have you submitted testimony in other administrative or judicial proceedings dealing with energy or related issues?

A: Yes. A list of those is attached as Applicants' Exhibit 2-B – all are in Minnesota.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q: What is the purpose of your testimony?

A: I will provide information about Great River Energy (GRE), and information on GRE's energy and demand forecasts, which justify GRE's need to secure additional sources of reliable, affordable power and energy in the year 2011 and beyond. I will also provide information about and explain why GRE concluded the Big Stone Unit II project was superior to all other alternative sources of power and energy in terms of meeting GRE's supply-side needs within the relevant timeframe. I will also provide information on GRE's current resource mix and on its demand-side management, energy conservation and renewable energy programs.

Q: Please summarize your testimony.

A: Reliable forecasts project there will be significant capacity shortages in the Mid-Continent Area Power Pool ("MAPP") region in the year 2011 and beyond. As shown in the Application, GRE projects having its own capacity shortage of 680 MW beginning in 2011. We expect this deficit to be reduced when our 170 MW Cambridge unit comes on line in 2007. As fiduciaries to GRE's members, GRE's directors and managers are obligated to ensure that it can supply enough power and energy to meet GRE's members' future needs. GRE must ensure that it can provide reliable and affordable power and energy. In connection with these power supply planning decisions, GRE's directors and managers are required to make informed, prudent and reasonable judgments, based on all available, relevant information. In the process of considering the various options for meeting GRE's supply needs in the year 2011 and beyond, GRE determined that the best option available was to participate in the Big Stone Unit II project, and, specifically, to subscribe for at least 116 MW of the anticipated 600 MW of the project's capacity.

III. DESCRIPTION OF THE COMPANY

Q: Please give a brief description of GRE.

A: Great River Energy is a not-for-profit Generation and Transmission (or "G&T") electric cooperative. GRE was formed by the consolidation of Cooperative Power and United Power Association on January 1, 1999. GRE's membership consists of 28 distribution cooperatives that provide electric service at retail to about 600,000 retail members, 99% of whom are in Minnesota, with the balance in Wisconsin. A list of GRE's members is attached hereto as Applicants' Exhibit 2-C, and is also available on-line at this URL: http://www.greatriverenergy.com/member/mc.html. GRE's member distribution cooperatives are geographically far-flung. GRE serves member cooperatives from southwest Minnesota, including Nobles Electric Cooperative in Worthington, Minnesota, and Federated Rural Electric Association in Jackson, Minnesota, to northeast Minnesota, including Arrowhead Electric Cooperative in Lutsen, Minnesota, and from west central Minnesota, including Lake Region Electric Cooperative in Pelican Rapids, Minnesota, to east central Minnesota, including East Central Energy in Braham, Minnesota, which serves customers in two counties in northwest Wisconsin. GRE's corporate headquarters are in Elk River, Minnesota. GRE's annual revenue is about $700 million; we have approximately 700 employees.

Q: Please describe the governance structure of your company.

A: GRE is owned by our 28 member cooperatives, which elect our 34-member board of directors. All of our board members are also board members of our member cooperatives. Therefore, each of our board members is also a consumer of electricity sold by one of our member cooperatives. Our board members are interested in assuring that we have reliable, low-cost, environmentally sound electricity by virtue of being consumers of our electricity, as well as through the democratic process by which they are elected. Our board of directors appoints a CEO who is responsible for running the cooperative. I report to the CEO.

Q: Explain the distinction between a "G&T Cooperative" and a "Distribution Cooperative."

A: Functionally, GRE and other G&T Cooperatives are wholesale suppliers of power and energy. However, instead of engaging in arms-length transactions with retail distributors of electricity, GRE serves as the supplier of power and energy to its member distribution cooperatives. In turn, the distribution cooperatives deliver power and energy to their members.

Q: Who are the consumers of the electricity provided by cooperatives?

A: The "owners" of the distribution cooperatives are also the consumers of the power and energy the distribution cooperatives provide. Similarly, the distribution cooperatives are both the owners and the consumers of the power and energy generated and transmitted by the G&T cooperatives. Thus, by virtue of this vertically integrated supply, ownership and governance structure, the consumers and ratepayers are responsible for providing power and energy to themselves. It is evident from this structure that the owners/consumers have a powerful incentive to secure reliable sources of supply at affordable rates, and to generate, transmit and distribute power and energy to all members as efficiently as possible. Similarly, there is absolutely no incentive to select generation or other resources that are (in relative terms) unproven, unreliable, undependable or unnecessarily expensive. Seen in this light, electrical cooperative systems are very much like municipal/public power systems.

Q: Are electric cooperatives like GRE and GRE's members different from investor owned electric utilities like Otter Tail Power Company?

A: Yes. In accordance with state and federal law, both G&T and distribution cooperatives have certain rights, privileges and immunities with respect to their operations that differ from the laws that govern investor owned utilities. The most prominent difference is how the two different types of utilities set their rates. Generally speaking, investor-owned utilities have their rates set by the regulatory commissions of the states where their retail customers consume the power and energy the investor owned utility supplies. For example, the South Dakota Public Utilities Commission has jurisdiction over Otter Tail's revenue requirement and rates for electric service to Otter Tail's retail customers in the state of South Dakota. In contrast, because electric cooperatives are member-owned, the Minnesota legislature allows each cooperative's members to decide whether its rates should be set by the Minnesota Public Utilities Commission (MPUC).

Only one Minnesota electric cooperative, Dakota Electric Association, GRE's second-largest member, is rate-regulated at the present time. For all other cooperatives, the MPUC does not set rates; they are established by the cooperative's board of directors, which is elected by the consumer-owners of the cooperative. Similarly, at the wholesale level, GRE's rates are not set by the Federal Energy Regulatory Commission (FERC). Again, GRE's principal wholesale customers are its member-owners.

IV. PARTICIPATION IN BIG STONE

Q: Why did GRE become interested in participating in Big Stone Unit II?

A: For many years, GRE's management and staff have identified power and energy shortages beginning in the 2010 and 2011 timeframe. These shortages were consistent with the forecasting conclusions of other utilities in the region, as reflected in the long-term load and capability forecasts of the Mid-Continent Area Power Pool (MAPP) for the same timeframe. GRE has reported its conclusions regarding these shortages to its members, to MAPP, to other utilities and to the Minnesota Public Utilities Commission in connection with GRE's biennial integrated resource plan filings. Because these forecasted regional and company-specific shortages are genuine and of substantial magnitude, GRE is obligated to obtain additional generation to provide sufficient power and energy to its members.

Otter Tail Power Company approached GRE several years ago and asked if we were interested in participating in the development of a baseload project possibly to be located at the site of the Big Stone power plant in Big Stone City, South Dakota. GRE's management decided to participate in the project because it was evident the proposed new plant would be the only available supply-side resource option what would meet all of GRE's three main criteria for generating resources GRE needed beginning in 2011: it will be reliable, the power and energy it will produce will be low-cost, and the plant will have environmentally sound attributes.

Q: Has GRE officially approved participation in the Big Stone Unit II Project?

A: Yes. GRE's participation has been approved by the board of directors and by its membership.

Q: What is GRE's share of Big Stone Unit II?

A: We will take 116 of the 600 megawatts. We have offered to take more, if it were available. Our rate of growth will certainly justify more than 116 MW.

Q: How is GRE going to pay for its share of the construction and operating costs of Big Stone Unit II?

A: We plan to use 100 percent debt financing by taking loans from the Federal Financing Bank that are guaranteed by the Rural Utilities Service (RUS) of the United States Department of Agriculture. This is a conventional form of financing for GRE. We may use CoBank, a cooperative bank located in Denver, Colorado, for interim construction financing until the RUS debt is obtained. We have an established banking relationship with CoBank, and have used its construction financing in the past. The operating costs of this project will be rolled into our revenue requirement. Our board of directors revises our rates annually, and our 28 members are contractually obligated to pay rates that cover our cost of service. This is proven, reliable technology, and financing it should not be a problem for GRE.

Q: Why did GRE conclude that a pulverized coal plant was reliable?

A: A supercritical, pulverized coal baseload plant is proven technology that will have a very high availability factor. Once the plant is operating, the plant's design engineers expect it to be available to produce power and energy twenty-four hours a day, seven days a week, in excess of 95% of the time, exclusive of outages for scheduled maintenance.

Q: What did GRE rely on to conclude that a pulverized coal plant was low cost?

A: Burns & McDonnell determined that a 600 MW supercritical PC unit had the lowest cost of all the alternatives examined. Also, Big Stone Unit II will share infrastructure with the existing Big Stone Unit I. The shared facilities and personnel will act to reduce the costs of both units. In addition, we conducted a request for proposals (RFP) to see if any viable baseload options were available that were lower in cost than Big Stone Unit II. There were none.

Q: What steps are being taken to control emissions from Big Stone Unit II?

A: The air permit for the project will require that it have the Best Available Control Technology (BACT) on air emissions. The plant's modern, supercritical design will make it more efficient. It will produce 18 percent less CO_2 per megawatt-hour than existing coal-based power plants in the region. We will go beyond that by super-sizing the scrubber so that it will scrub the flue gas from Unit I as well as Unit II. Unit I is currently an unscrubbed unit. In all, we expect that total emissions of sulfur dioxide, and nitrogen oxides will be less with both units operating than historically what has been emitted from Unit 1 alone. This is a major environmental benefit. In addition, we intend to super-size the transmission outlet for electric power and energy from future generating resources, including significant amounts of more wind power. A portion of the transmission outlet will connect to the "Ridge to Metro" 345kV project that will also facilitate the delivery of wind power.

Q: Why does GRE prefer supercritical, pulverized coal rather than other options such as natural gas or nuclear power?

A: Producing electricity by using natural gas is a reliable technology, but is very expensive. Natural gas prices have a history of extreme variability that makes natural gas an undesirable fuel for baseload applications. As a peaking fuel, natural gas will continue to have value in simple-cycle combustion turbines because of their ability to start quickly, and because relatively little natural gas is used by peaking plants. Nuclear power has been on hold, as far as new plant development goes in the United States, since the accident at the Three Mile Island plant in the late 1970's. However, nuclear power has no carbon dioxide emissions, which makes it a promising technology. Nevertheless, we at Great River Energy do not want to be the first ones to build a new nuclear power plant in the United States. The risk is too great until the new nuclear designs have proven themselves to be commercially viable and a method for handling the radioactive waste is implemented.

Q: Why don't you just build more wind generation?

A: We are going to build more wind power. We brought 100 MW of wind power on line in November 2005. We now have a total of 118 MW. We will at least double that amount by the end of 2007. By the time Big Stone Unit II is in operation in 2011, GRE projects having in excess of 300 MW of wind power providing electricity to our members. We are quickly developing wind power, but we still need our share of Big Stone Unit II.

Q: Did GRE consider constructing an Integrated Gasification Combined Cycle (IGCC) plant?

A: Yes, we did. IGCC is promising technology. GRE expects that it will become involved in an IGCC project at some point in the not too distant future. However, on several important levels it is presently a poor substitute for a proven technology like supercritical pulverized coal. The Wisconsin Public Service Commission recently confirmed this point when it rejected a proposal by Wisconsin Electric Power Company to construct and operate a 600 MW IGCC plant in eastern Wisconsin. The commission ruled that "IGCC technology, while promising, is still expensive and requires more maturation." One of its main objections was that the utility would have to raise electricity rates to cover the premium cost of building the plant. Consumer-protection and environmental groups appealed the panel's decision, and the Wisconsin Supreme Court affirmed the decision of the commission "in all respects," in June 2005.

There are only two IGCC power plants in operation in the United States at this time. Both of them use eastern bituminous coal, which is substantially easier to gasify than the higher-moisture sub-bituminous and lignite coals available in this part of the country. Both plants started out with very low availability, and have reached as high as 80% availability only in their fifth year of operation. Both plants received significant subsidies from the United States Department of Energy (DOE). A third coal gasification power plant, Piñon Pine, never did start up successfully. So no, IGCC is not as reliable as supercritical pulverized coal technology.

Q: Are IGCC power plants lower in cost than pulverized coal?

A: No. According to information from the Electric Power Research Institute (EPRI) and third party consultants, the capital costs of IGCC power plants are about 20% higher than supercritical, pulverized coal plants when utilizing coal from the Powder River Basin (PRB). The all-in costs, including both capital and operating costs, will be 25-30% higher than supercritical, pulverized coal, which takes into account not only the higher capital costs but also the reduced availability of the IGCC plant.

V. RISK FACTORS

Q: Did the Applicants consider the risk of future carbon dioxide regulation or taxation in their analysis?

A: Yes. Because of the potential that there could be carbon dioxide regulation within the time period that Big Stone Unit II is operational, Burns & McDonnell Analysis of Baseload Generation Alternatives Report tested the economics of Big Stone Unit II against the economics of other possible baseload plants under different scenarios of carbon dioxide regulatory costs. In each case, Big Stone Unit II remained the most desirable baseload choice.

As to a potential IGCC plant, the Burns & McDonnell report found that, because carbon dioxide emissions from IGCC plants are only slightly lower than from a super-critical conventional coal plant, a potential carbon dioxide tax would not overcome the cost disadvantage and the technology challenges of an IGCC plant. It may be possible at some future date to design an IGCC plant that captures carbon dioxide and can make arrangements both for transporting the carbon dioxide to an underground storage area and for storing the carbon dioxide long-term. Carbon capture, transportation, and storage could be applied to either IGCC or pulverized coal plants. However, carbon capture, transportation, and storage would make either an IGCC or pulverized coal plant even more expensive, and currently carbon capture is not practiced at either of the IGCC or pulverized coal plants in the United States.

A potential carbon tax would tend to make the nuclear option more attractive economically as compared with a coal plant. However, nuclear has its own technology challenges, including unresolved issues as to spent fuel storage, that make the nuclear option unattractive to the applicants no matter what the carbon tax might be.

Burns & McDonnell also tested the economics of Big Stone Unit II under carbon tax scenarios as compared with an alternative of combining wind and natural gas generation to create baseload power. As determined by Burns & McDonnell, with natural gas at a cost of \$7/mmBTU in 2011, a carbon dioxide tax would have to equal \$14.00 per ton (for an IOU ownership structure) and $23.00 per ton (for a public power ownership structure) before it would be more economical to rely on a combination of wind power and combined-cycle natural gas generation. However, these numbers understate the advantage of the super-critical pulverized coal option as compared with a wind-gas alternative. First, these numbers are considerably higher than Minnesota's carbon dioxide environmental externality values that, in any event, don't apply to out-of-state generation. Second, these numbers assume continuation of the 1.9 cents/kWh wind energy tax credit, an assumption that is not at all certain. Third, as noted, natural gas prices pose their own high-side risks. Fourth, the gas-wind option has an all-in cost approximately 37 percent higher than Big Stone Unit II with no carbon dioxide cost. The Applicants do not believe it prudent to put that added burden on their ratepayers without some certainty as to the future of carbon dioxide regulation.

Q: What other risk factors did you take into account?

A: Another risk factor that was considered was the risk of increases in the cost of operating the plant, particularly from the increases in fuel costs. Burns & McDonnell's Analysis of Baseload Generation Alternatives Report included sensitivity analyses for the principal assumptions in the report (capital costs, interest rates, capacity factor, fuel cost, O&M costs and wind energy purchase costs). The report found that the economics of the baseload coal plant alternative were robust for the different sensitivity analyses.

VI. RESOURCE PLANNING

Q: Have your professional responsibilities included involvement in resource planning?

A: From March 2002 until July 2005, I served as GRE's Vice President of Corporate Services. In this position I was responsible for managing GRE's Resource Planning Department, which estimates our future needs and plans for future resource additions.

Q: Please describe the process your company undertakes to plan future power and energy resources to meet its members' obligations.

A: Every two years, GRE prepares an integrated resource plan (IRP or resource plan) to plan for our members' future needs. The IRP covers a fifteen-year planning horizon and is prepared to comply with the rules of the Minnesota Public Utilities Commission (MPUC). The most recent plan was filed on June 30, 2005. This plan is currently under review by the MPUC.

Q: What is the purpose of the integrated resource plan?

A: The IRP presents capacity and energy forecasts and then compares those forecasts with GRE's existing resources to determine our resource requirements over the planning period. GRE then models various resource options to determine a preferred plan that minimizes costs and risks over the planned period.

VII. FORECASTING

Q: Does GRE forecast future energy and demand requirements?

A: Yes.

Q: What are the sources of information for the forecasts?

A: GRE's forecast is the sum of its 28 member systems' energy and demand forecasts. GRE assists the member systems in the development of their forecasts by providing information that is useful in quantifying their future loads and in determining if their forecasts are reasonable. The forecasting methodology followed by GRE and its members is designed to comply with the requirements of the Rural Utilities Service (RUS) and an updated forecast is prepared every two years for RUS approval.

Q: What are your company's future power and energy needs?

A: Tables 3-3 and 3-4 of the application show both the historic and forecasted demand and energy requirements for GRE. Applicants' Exhibits 2-D and 2-E attached to this testimony provide that same information graphically. GRE forecasts that from 2004-2023 its demand will increase an average of approximately 96 MW per year. During the same period, GRE forecasts its energy requirements will increase by an average of approximately 337,500 MWh per year.

Q: What has been the annual rate of growth in GRE's demand?

A: The compound annual growth rate of demand from 1980-2003 was 4.1 percent. During the 10 years from 1993-2003, the compound annual growth rate of demand was even higher, 5.4%.

Q: What has been GRE's annual rate of growth in energy?

A: The compound annual growth rate in energy from 1980-2003 was 3.8 percent. During the 10 years from 1993-2003, the compound annual growth rate of energy was 4.3%.

Q: Why did demand grow faster than energy?

A: We are primarily a residential and small commercial utility. A lot of our growth consists of new homes and businesses in the Twin Cities' suburbs that have electric air conditioning and natural gas heat. Air conditioning contributes significantly to summer peak demand, but does not contribute that much to energy.

Q: What are the most recent forecasts for your company's future power and energy needs?

A: GRE's most recent forecast is its 2004 load forecast. GRE's most recently accepted IRP is its 2003 filing, which contained its earlier 2002 load forecast. Its 2005 filing is currently under review by the MPUC.

Q: Where in the Application are your company's forecasts of future power and energy needs presented?

A: GRE's forecast and resource plans are discussed in the application starting on page 47 and ending on page 52. Exhibits 3-6 and 3-7 graphically represent GRE's projected surplus/demand and energy needs.

VIII. GENERATING RESOURCES

Q: What are GRE's existing generating resources?

A: As of the summer of 2005, GRE owned or participated in approximately 1,471 MW of baseload resources; 1,033 MW of peaking resources; and 39 MW of waste to energy (designated as a renewable resource in Minnesota). GRE also has several medium and longer term purchase contracts totaling 465 MW, most of which have contractual terms and conditions similar to those of an intermediate resource. In November of 2005, GRE began receiving energy from the 100 MW Trimont Area Wind Farm. With this addition, GRE has a total of 118 MW of wind resources under contract. In 2006, GRE expects to award another contract for wind of at least 120 MW.

Q: What are GRE's current generating capability and its power and energy resources?

A: GRE owns about 2500 megawatts (MW) of generation. Its resource mix is diverse. In 2006, GRE will use the following fuel mix to generate electric energy:

- Coal-based power plants in North Dakota (68 percent)
- A purchase from a coal-based power plant in Wisconsin (8 percent)
- Natural gas-fired peaking plants in Minnesota (2 percent)
- Other purchased power (15 percent)
- Hydropower from the Western Area Power Administration (3 percent)

- A refuse-derived (municipal waste) power plant at Elk River, Minn. (1 percent)
- Wind energy in Minnesota (3 percent).

Q: What percentage of GRE's energy is from renewable energy sources?

A: The energy from the Western Area Power Administration (WAPA) comes from large hydropower dams. The Minnesota legislature and Public Utilities Commission do not classify power and energy produced by WAPA's hydroelectric plants to be power and energy produced by a renewable resource. Thus, under Minnesota law and Minnesota Public Utilities Commission resource planning standards, GRE's renewable energy percentage is four percent of total generation.

Q: Are GRE's costs of generating resources accurately represented as part of Exhibit 3-3 to the Application?

A: Exhibit 3-3 is a generic representation of the total cost of a baseload, intermediate, and peaking plant as a function of its capacity factor. For each utility the curves might be somewhat different depending on the cost of money, fuel costs and technology assumptions. The general conclusion represented in the exhibit does represent GRE's position; that at moderate to high capacity factors, baseload resources such as Big Stone Unit II are the least-cost resource type.

Q: Are GRE's existing generating resources sufficient to meet its forecasted energy and demand requirements?

A: Based on GRE's continued strong load growth and the expiration of several purchase contracts, GRE projects a capacity deficit of approximately 680 MW in 2011, the year Big Stone Unit II is projected to be in service. GRE has approval for the construction of a 170 MW peaking station to be in service in 2007. So without its share of Big Stone Unit II, GRE projects a deficit of approximately 510 MW in 2011.

Q: How is GRE's energy delivered to its members?

A: GRE owns over 4,500 miles of transmission lines in Minnesota, Wisconsin and North Dakota. GRE is a member of the Midwest Independent System Operator (MISO), which facilitates and coordinates he use of GRE's and other MISO members' transmission systems. GRE has a long history, pre-dating MISO, of sharing transmission facilities with other utilities, including Otter Tail Power Company, Minnesota Power, and Xcel Energy.

IX. DEMAND-SIDE MANAGEMENT

Q: Does GRE consider the effects of demand side management as part of its resource planning process?

A: Yes.

Q: Please explain that process.

A: GRE's forecasting methodology relies on historic usage patterns and load factors to forecast future needs. As such, GRE's load forecast incorporates the effects of demand side management programs' continuing to be added or expanded at approximately the same rate at which they have increased in the past. GRE has a strong commitment to demand side management and has been actively working to continue making improvements to its program. GRE's load management efforts have resulted in reducing GRE's peak demand by approximately 300 MW, the equivalent of a large power plant. GRE also estimates that its conservation programs reduced energy usage in 2004 by approximately 140,000 MWh. This commitment is further evidenced by the fact that spending by GRE and its members on demand side management programs significantly has exceeded the minimums established by Minnesota law. In 2004, GRE and its members spent nearly $15 million dollars on demand side management programs, 145% over the minimum requirement.

Q: How does GRE decide which demand side management programs to develop?

A: In developing demand side management programs, GRE's direction is to focus on those programs that best match the type of energy resources that are projected to meet future needs. In the past, that focus has been on reducing the summer peak demand. GRE will continue to offer programs to reduce those peaks. Because GRE has an increasing need for additional baseload, GRE has increased its focus on conservation programs.

X. SELECTION OF BIG STONE UNIT II

Q: What type of generating resources does your company project it will need to add to meet the forecasted customer power and energy needs?

A: In its 2003 IRP, GRE identified the need to add baseload resources in the 2010 – 2103 timeframe. With the selection of Big Stone Unit II, the updated action plan included in the 2005 IRP indicates that future baseload resource additions can be postponed until the 2014-2106 timeframe. The action plan further identifies the addition of 300 MW of peaking in the 2008-2009 period and 235 MW of intermediate in 2010. GRE also anticipates, assuming that the modeled price of wind energy does not change significantly, that it will add approximately 400 MW of wind resources by 2015 to achieve the Minnesota Renewable Objective of providing at least 10% of its energy from renewable resources.

Q: How was Big Stone Unit II selected to meet a portion of GRE's resource needs?

A: Page 51 of the application summarizes the process that GRE used in selecting resources to meet its identified needs, including how Big Stone Unit II was selected to meet a part of the baseload resource need identified in its 2003 IRP. Prior to the selection of Big Stone Unit II, GRE issued a Request for Proposal (RFP) for baseload resources. The results of the RFP showed Big Stone Unit II to be the only viable option for baseload power available at that time.

Q: What resources will be available to meet future power and energy requirements if Big Stone Unit II is not constructed?

A: If Big Stone Unit II were not constructed, GRE would, in the short term, meet this need through market energy purchases and the construction of a gas-fired peaking facility. To meet the identified need for the long term, GRE would participate at a larger share in our next baseload resources anticipated to be developed in the 2014-2016 timeframe. GRE has compared the costs of this "no-build" alternative to Big Stone Unit II. For GRE's share, over a ten-year period (2011-2020), the present value cost of the no-build alternative is approximately $ 27 million dollars higher than Big Stone Unit II and carries with it an increased risk.

Q: Will Big Stone Unit II meet all of GRE's projected energy requirements?

A: No. GRE's 116 MW share of Big Stone Unit II will meet only a portion of our forecasted needs. In addition to Big Stone Unit II, GRE forecasts the need to add peaking and intermediate resources in the 2008-2010 timeframe as well as 600 MW of additional baseload in the 2014 – 2016 timeframe.

Q: Does this conclude your testimony?

A: Yes.