APPLICANTS' EXHIBIT 25

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

KIAH E. HARRIS

PROJECT MANAGER BUSINESS & TECHNOLOGY SERVICES

BURNS & McDONNELL ENGINEERING COMPANY

MARCH 15, 2006

BIG STONE II

PARTNERS IN GENERATION

TESTIMONY OF KIAH E. HARRIS

TABLE OF CONTENTS

BFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY OF KIAH E. HARRIS

I. INTRODUCTION

Q: State your name and business address.

A: Kiah Edward Harris, 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. as a Project Manager in the Business and Technology Services Group.

Q: What is your educational background?

A: I hold a Bachelor of Science in Electrical Engineering and a Master of Science in Electrical Engineering from the University of Missouri.

Q: What is your employment history?

A: I have been employed by Burns & McDonnell for twenty-five years. For the past seventeen years, I have been a Project Manager in the Business and Technologies Division.

Q: What work experience have you had that is relevant to your testimony?

A: As Project Manager in the Business and Technologies Division of Burns & McDonnell, I have been responsible for the transmission and generation resource plans for utilities. I have prepared transmission and generation resource plans for municipal, cooperative and investor-owned utilities. These resource plans have included a variety of fossil fired and renewable generation options. I have also analyzed demand-side management programs and their expected impacts for utilities.

Q: What professional organizations do you belong to?

A: I am a licensed professional engineer in the states of Colorado and Wisconsin.

Q: Have you provided testimony dealing with energy or related issues?

A: Yes. My previous testimony is described in Applicants' Exhibit 25-A.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q: What is the purpose of your testimony?

A: In a December19, 2005 Order of the Minnesota Public Utilities Commission (MPUC), the MPUC ordered the Applicants in their request for Certificate of Need for proposed transmission facilities in Minnesota to provide the MPUC with information regarding generation and demand-side alternatives to the proposed Big Stone II Unit. The MPUC listed a number of specific information points that it wanted addressed. The Applicants retained Burns & McDonnell to assist in responding to that list of information points. Effectively, the information sought, among other things, what the costs of the next best resource alternatives to the Big Stone Unit II would be. A copy of the responsive report is included as Applicants' Exhibit 25-B. My testimony here provides a summary of the results of that responsive report.

Q: Please summarize your testimony.

A: My testimony addresses ARSD 20:10:22:30, which requires in part that Applicants discuss reasons for selecting the proposed energy resource versus alternative resources. If Big Stone Unit II is not constructed, there is no single next best resource alternative that Applicants would collectively pursue. Instead, each Applicant would pursue a variety of strategies to meet their obligations. On a collective basis, the separate resource strategies will be significantly more expensive than is the resource alternative that includes Big Stone Unit II.

III. COMPARATIVE COST OF RESOURCE SCENARIOS

Q: What was the purpose of preparing Applicants' Exhibit 25-B?

A: Burns & McDonnell was retained to coordinate and assist with preparing the Applicants' collective responses to the MPUC's request for additional information on Big Stone Unit II. Working with the Applicants, we analyzed the total costs of the individual Applicants' resource scenarios that both include and exclude the proposed Big Stone Unit II. We also developed costs of environmental externalities associated with the two resource scenarios since, in Minnesota, utilities are required to apply certain externality costs associated with certain power plant emissions in their evaluation of resource decisions. In order to develop the costs of the externalities, the Applicants developed what the expected emissions were from the resource scenarios with and without Big Stone Unit II. We then determined what the incremental emissions would be for the combination of Applicants' resource scenarios. We applied the externality values, as adopted by the MPUC, to these incremental emissions.

Q: Did Burns & McDonnell assist any of the Applicants in the development of their resource planning and analysis?

A: Burns & McDonnell had been retained under a separate agreement by Heartland Consumers Power District to assist it in evaluating a variety of resources associated with meeting their power supply obligations. Because of this earlier assignment, we assisted Heartland in preparing their response to the additional information in Applicants' Exhibit 25-B.

Q: Did Burns & McDonnell assist any other of the Applicants in developing their response?

A: No.

Q: What was the result of your work in comparing the costs of Big Stone Unit II to each of the Applicants' individual "next best" resource scenario?

A: Burns & McDonnell combined the Applicants' individual resource scenarios to determine the revenue requirements with and without Big Stone Unit II in the resource mix. We determined the incremental revenue requirements between the resource scenarios and developed the net present value of revenue requirements in 2011 dollars. This allowed us to compare the costs of the two future resource scenarios.

The resource scenario with Big Stone Unit II had revenue requirements of approximately $669,141,000 lower than the resource scenario without the unit.

Q: What types of alternatives would the Applicants be likely to implement in order to meet their resource needs in the future without Big Stone Unit II?

A: The Applicants would need to look to add a variety of resource alternatives, including market purchases, gas and coal-fired generation, and renewable energy resources. In addition, the Applicants would also likely include demand-side management (DSM) programs managed directly by the utility or indirectly through member utilities, though DSM activities are also included in the resource scenario that includes Big Stone Unit II. Each Applicant would pursue a variety of resource options, and the most likely alternatives for each Applicant are discussed in Part A of Applicants' Exhibit 25-B.

Q: How was the information related to externalities developed?

A: The Applicants provided the estimated emissions from the alternative resources in the resource scenarios with and without Big Stone Unit II. The emissions were estimated for market purchases using the most recent externality values adopted by the MPUC. The incremental emissions were developed for the resource scenario that both include and excludes Big Stone Unit II. The emissions for the Big Stone Unit II were determined by Burns & McDonnell. The emission weights were multiplied by the MPUC approved externality values (as adjusted for inflation) to arrive at the externality costs by year for the two resource scenarios. Both the high and low values were used from the applicable MPUC externalities. The externality costs were added to the revenue requirements to reflect the cost of the resource scenarios with externality costs included.

Q: Were there any special considerations made for the externalities?

A: Yes. In addition to the quantities requested by the approved MPUC process, the Applicants provided the incremental amount of CO_2 that would be emitted from resources outside the state of Minnesota for the with and without Big Stone Unit II resource scenarios. This was necessary because the MPUC does not have an externality value for CO_2 that would apply to outstate resources.

Q: What was the conclusion from adding externality costs to the revenue requirements?

A: The resource scenarios with Big Stone Unit II, even with the externality costs from the three approaches used added to the revenue requirements, was lower cost than the sum of the individual Applicants' resource scenarios that did not include Big Stone Unit II.

Q: Does this complete your testimony?

A: Yes.

Kiah E. Harris, P.E.
Principal

Testimony and other Regulatory Matters - Kiah Harris

2004
Case No. 42824 PETITION OF WHITING CLEAN ENERGY, INC., ENERGYUSA-TPC CORP., and NORTHERN INDIANA PUBLIC SERVICE COMPANY, FOR AUTHORIZATION FOR WHITING CLEAN ENERGY, INC. TO SELL ELECTRIC POWER TO ENERGYUSA-TPC CORP. AND NORTHERN INDIANA PUBLIC SERVICE COMPANY TO PURCHASE THAT ELECTRIC POWER FROM ENERGYUSA-TPC CORP.

2002
Case No. 42079 Indiana Utility Regulatory Commission
Hoosier Energy Rural Electric Cooperative, Inc.
Integrated Resource Plan

2001
Case No. 97-0046 COMMONWEALTH UTILITIES CORP. v. GOLTENS TRADING & ENGR, PTE., LTD., and IN-PLACE MACHINING COMPANY, INC., United States District Court for the Northern Mariana Islands.

2000
Kentucky Utilities Board
Big Rivers Integrated Resource Plan

1999
Docket No 98-183-TD Newark School District v. City Water and Light of Jonesboro, Arkansas. Arkansas Public Service Commission

1990-1993 Rate filings for Tri-County Electric Cooperative, Texas Public Utilities Commission

2060

EXHIBIT
Applicants'
EX 25-A

PO Box 496
215 South Cascade Street
Fergus Falls MN 56537

Big Stone
Partners in Transmission

Applicants' Supplemental Information Required by Commission's Order of December 19, 2005

Application to the Minnesota Public Utilities Commission for Certificate of Need for Transmission Lines in Western Minnesota

Submitted by:

Central Minnesota Municipal Power Agency
Great River Energy
Heartland Consumers Power District
Missouri River Energy Services
Montana-Dakota Utilities Co.
Otter Tail Power Company
Southern Minnesota Municipal Power Agency

February 28, 2006

EXHIBIT
Applicants'
EX 25-B

2061

Table of Contents

APPENDICES

LIST OF TABLES

LIST OF FIGURES

SUMMARY

This report responds to the December 19, 2005 Order[1] (Order) of the Minnesota Public Utilities Commission (Commission) requiring the Applicants to provide additional information about their alternative power supply plans if Big Stone Unit II, being proposed for construction in South Dakota, was not built.

Not surprisingly, there is no equivalent "single" next best alternative project that the Applicants would pursue if Big Stone Unit II was not built. Instead, each of the Applicants would pursue a variety of alternatives on an individual basis. For some, those alternatives include other potential coal projects. For others, the alternatives include a combination of gas-fired power plant construction along with market purchases. For others, the alternatives include a combination of many different resources.

In preparing this report, the Applicants used a combination of supply and demand-side options and developed revenue requirements for the future resource scenarios with and without Big Stone Unit II. The analysis shows that the scenarios considering Big Stone Unit II in the Applicants' resource mix have, on a combined basis, a net present value (NPV) of revenue requirements which is $669,141,000 lower than the revenue requirements for the combined alternative resource scenarios without Big Stone Unit II. The scenarios with Big Stone Unit II available in the Applicants' resource mix represent a net present value savings of approximately 9 percent when compared to scenarios without Big Stone Unit II in the Applicants' resource mix.

The analysis also developed and compared emissions in scenarios with and without Big Stone Unit II. The analysis used the numerical externality values adopted by the Commission to assess costs to each respective externality. In addition, the Applicants prepared an additional scenario that applied the Commission approved externality value for CO_2 to Big Stone Unit II and to other generation resources outside of Minnesota, even though the Commission has not adopted an externality value for CO_2 emission sources located outside of Minnesota. In this way, the incremental CO_2 emissions from all resources and market purchases resulting from the Applicants' alternative individual resource scenarios were compared to the CO_2 emissions from Big Stone Unit II so as to provide an all inclusive look at CO_2 emissions.

[1] Order Accepting Application as Substantially Complete and Requiring Additional Information. Docket Nos. ET-6131, ET-2, ET-6130, ET-10, ET-6444, ET-017, ET-9/CN-05-619.

The externality costs in scenarios with and without Big Stone Unit II are summarized in Table 1. The "High" externality values represent those values from the Rural and Within 200 Miles of Minnesota categories of externalities priced at the high end of the Commission values. The "Low" column represents the costs resulting from using the low end of the Commission values. The "All CO_2" case represents the costs resulting from using the high end of the Rural Minnesota cost of CO_2 applied to the CO_2 resulting from the incremental levels of CO_2 between the scenarios captured for all resources, regardless of location.

Table 1
Incremental Net Present Value Costs

	High	Low	All CO_2
Externalities With BSUII	$7,409,000	$4,222,000	$158,270,000
Externalities Without BSUII	$56,454,000	$12,100,000	$142,660,000
Externality NPV Benefit (Cost) with BSUII	$49,045,000	$7,879,000	$(15,610,000)
Resulting Difference Between NPV of Revenue Requirements of Applicants' without BSUII scenarios minus the NPV of RR with BSUII with Externalities included	$718,185,000	$677,019,000	$653,531,000

When comparing the net present value difference of benefits and costs (line 3 in Table 1) of the externalities against the net present value difference in revenue requirements between the two scenarios ($669,141,000), the benefits and costs of externalities is approximately 1.2 to 7.3 percent of the net present value difference of revenue requirements. As shown, with the externality costs considered in accordance with the Commission's approach or including all of the incremental CO_2, the scenarios with Big Stone Unit II have an overall lower net present value cost of between approximately 8.9 to 9.9 percent than the alternative future resource scenarios without Big Stone Unit II.

An emission benefit from the Big Stone Unit II project is the reduction in SO_2 emissions from Big Stone Unit I that will occur due to use of a common wet scrubber for the two units. The proposed common wet scrubber and associated fabric filter for Big Stone Unit I and Big Stone Unit II are also the emission control technologies that offer the best opportunity for mercury removal. The United States Environmental Protection Agency has concluded that a fabric filter followed by a wet scrubber (the proposed control technology) would exhibit greater mercury removal than other conventional emissions control configurations when firing sub-bituminous coal. The alternate scenarios do not include the addition of the common scrubber, therefore Big Stone Unit I would not have the projected reduction in SO_2 emissions if Big Stone Unit II were not constructed.

In conclusion, the additional information provided in this report confirms that the Applicants' resource scenarios with Big Stone Unit II provide an overall lower cost option by approximately 9 percent to meeting the Applicants' power supply needs than the resource scenarios without Big Stone Unit II, even considering environmental costs. In addition to the cost benefits, Big Stone Unit II provides significant upgrades to the transmission capacity in southwest Minnesota, including the first phase of a transmission expansion plan of the 345kV system from western and southwestern Minnesota to the Twin Cities, which would not necessarily occur if the alternative scenarios were pursued.

Purpose

This report was prepared in response to the Commission's Order requiring the Applicants to provide additional information on the following matters:

A. For each participating utility, construct the generation and demand-side management alternative considered most viable to match approximately the megawatt share that utility would receive from the Big Stone Unit II plant in 2011.

B. Including the environmental cost values adopted by the Commission, compare and contrast the costs of the resulting overall generation and demand-side management alternative (i.e., the combination of all seven sub-alternatives and associated transmission improvements) with the Big Stone projects (i.e., Big Stone Unit II plus the preferred transmission alternative provided in the application).

C. To the extent possible, discuss the comparative reliability of the resulting overall generation and demand-side alternative with that of the Big Stone projects.

D. To the extent possible, further compare the resulting overall generation and demand-side alternative with the Big Stone projects, considering the data elements listed in Minn. Rules, part 7849.0340, item B.

E. To the extent possible, discuss how changes in demand or changes in the in-service dates of the indicated resources would affect the above comparisons.

F. Provide any other information deemed relevant to comparing the Applicants' proposal and the alternative described above.

As the Certificate of Need Application (Application) makes clear, subject to permitting, the Applicants have agreed to jointly develop the Big Stone Unit II coal-fired power plant to be located in northeast South Dakota at the site of the existing Big Stone Unit I power plant. The planned Big Stone Unit II is nominally rated 600 MW and will use Powder River Basin coal. The in-service date for Big Stone Unit II is planned for 2011. Big Stone Unit II includes the addition of air emission controls for sulfur dioxide that also will be used to reduce SO_2 emissions from the existing Big Stone Unit I.

In response to the Applicants' request for interconnection service for Big Stone Unit II, those personnel responsible for transmission planning within the Applicant group have proposed certain transmission improvements in both South Dakota and Minnesota. Those transmission improvements (Projects) are the subject of the Application.

The percentage ownership and resulting nominal MW allocations from the proposed Big Stone Unit II are:

- 5.0% - 30 MW Central Minnesota Municipal Power Agency (CMMPA)
- 19.33% - 116 MW Great River Energy (GRE)
- 4.2% - 25 MW Heartland Consumers Power District (Heartland)
- 19.33% - 116 MW Montana-Dakota Utilities (Montana-Dakota)
- 19.33% - 116 MW Otter Tail Power Company (OTP)
- 7.8% - 47 MW Southern Minnesota Municipal Power Agency (SMMPA)
- 25.0% - 150 MW Western Minnesota Municipal Power Agency represented by Missouri River Energy Services (MRES)

The Applicants represent a variety of utility corporate structures. OTP and Montana-Dakota are vertically-integrated, investor-owned utilities. OTP provides services within Minnesota and, as such, is regulated by the Commission. Montana-Dakota is the only Applicant that does not have customers in Minnesota. Montana-Dakota serves retail customer load in North Dakota, South Dakota, Montana and Wyoming.

Heartland, CMMPA, MRES and SMMPA are municipal power agencies that provide wholesale power to municipal distribution utilities, which in turn provide retail electric service to their customers. CMMPA and SMMPA only serve member municipal utilities located within Minnesota. Heartland and MRES serve municipal utilities located in Minnesota, South Dakota, Iowa and North Dakota.

GRE is a generation and transmission cooperative that provides power at wholesale to member distribution cooperatives, who in turn distribute the power to retail customers. GRE provides power to member distribution cooperatives who serve load located primarily in Minnesota, with a small portion provided in Wisconsin. Further descriptions of the Applicants are provided in Sections 3.1 through 3.8 of the Application.

The Applicants prepare a variety of resource expansion plans in the course of their operations. OTP, GRE, SMMPA and MRES are subject to the Integrated Resource Planning (IRP) rules of the Commission. Heartland and CMMPA are not required to file under the IRP rules of the Commission because of their size and Montana-Dakota is not subject to the Commission's IRP rules because it does not serve any load in Minnesota. The most recent submission of IRPs for those utilities required to file them is shown in Table 2.

Table 2
Filing Dates for Integrated Resource Plans

	Latest Filed Plan	Date for Next Plan
GRE	June 30, 2005	July 1, 2007
MRES	July 1, 2005	July 1, 2007
OTP	July 1, 2005	July 1, 2007
SMMPA	July 1, 2003	July 1, 2006

Heartland and CMMPA prepare resource plans in their normal course of business, but are not required to and do not prepare IRPs or any similarly extensive resource plans. The plans they do prepare include load forecasts and review of resource options to most economically meet their member requirements. Montana-Dakota is required to file IRPs with the public service commissions in both Montana and North Dakota. Its most recent IRP filings were September 15, 2005 for both states. Its next IRP filings are September 15, 2007 for Montana and July 1, 2007 for North Dakota.

The Applicants' load forecasts were developed and compared to their existing resources to provide the forecast demand. Table 3 provides the forecast capacity deficits by Applicant from 2011, the earliest year that Big Stone Unit II could be commercial, to 2020. This information is taken from Appendix K, Table B-3 of the Application for each Applicant, which provides detailed information about the load forecast, capacity status and demand-side management programs for each Applicant.

Table 3
Applicants' Projected Capacity Conditions with Respect to Demand Load Forecast (MW)

Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
OTPCo	-129	-143	-161	-173	-187	-206	-218	-231	-244	-256
CMMPA	11	4	-3	-10	-18	-80	-88	-77	-92	-101
GRE	-680	-782	-888	-999	-1280	-1376	-1493	-1603	-1719	-1833
Heartland	-54	-58	-63	-111	-116	-116	-54	-57	-62	-66
MRES	-18	-36	-55	-73	-91	-181	-198	-214	-231	-246
MDU	-102	-107	-114	-120	-126	-135	-141	-147	-153	-159
SMMPA	-77	-86	-97	-106	-115	-124	-135	-144	-153	-163
Combined Deficit	-1049	-1208	-1381	-1592	-1933	-2218	-2327	-2473	-2654	-2824
Big Stone II Capacity	600	600	600	600	600	600	600	600	600	600
Resulting Capacity Needs	-449	-608	-781	-992	-1333	-1618	-1727	-1873	-2054	-2224

As shown in Table 3, the combined condition of the Applicants even after the acquisition of Big Stone Unit II is such that significant additional capacity will be required to meet the Applicants' forecasted demand. The Applicants are pursuing a variety of options to meet the capacity deficits above those satisfied by Big Stone Unit II.

The remainder of this report addresses the specific information required by the Order.

PART A

For each participating utility, construct the generation and demand-side management alternative considered most viable to match the megawatt share that utility would receive from the Big Stone II plant in 2011.

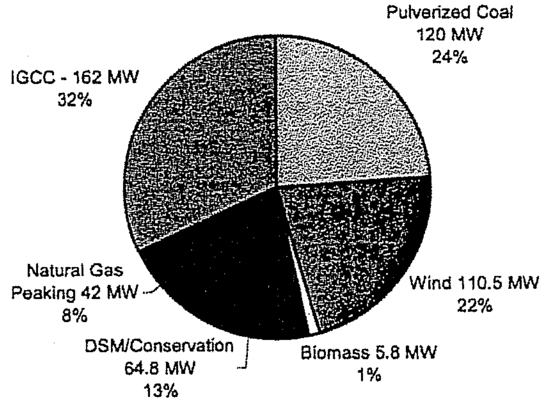
Otter Tail Power Company (OTP) - Development of the preferred OTP 2006 – 2020 resource plan began in late 2003 when OTP sought capacity and energy proposals from neighboring utilities and potential suppliers for use in developing the resource plan. Proposals were requested from, among others, the Manitoba Hydro Electrical Board (MHEB) and Excelsior Energy's proposed Integrated Gasification Combined Cycle plant proposed to be located in northeastern Minnesota. Three separate proposals were received from MHEB. During a phone conversation, Excelsior Energy declined to make a proposal, stating that their development process had not matured to a point where they would be in a position to make a proposal.

During 2004, OTP ran dozens of computer modeling scenarios to determine how baseload opportunities compared to each other. The results of these preliminary runs showed that one of the MHEB proposals appeared to rank as the second best baseload alternative to Big Stone Unit II.

OTP used the IRP-Manager optimization model to develop its 2006-2020 resource plan. A variety of resource alternative inputs to the model were used, including (1) demand-side management, (2) Big Stone Unit II, (3) aero derivative and heavy-duty natural gas-fired combustion turbines, (4) natural gas-fired combined cycle, (5) integrated gasification combined cycle, (6) wind, and (7) phosphoric acid fuel cells (PAFC). A number of other small distributed generation technologies were also screened prior to using the model and were eliminated from inclusion for a variety of reasons, including cost, resource availability, and size. In addition to that, distributed generation (DG) alternatives were also reviewed, but ultimately eliminated, included solar photovoltaic, landfill gas, and anaerobic digestion.

The resources selected by IRP-Manager for inclusion in the 2006-2020 resource plan are shown in Figure 1.

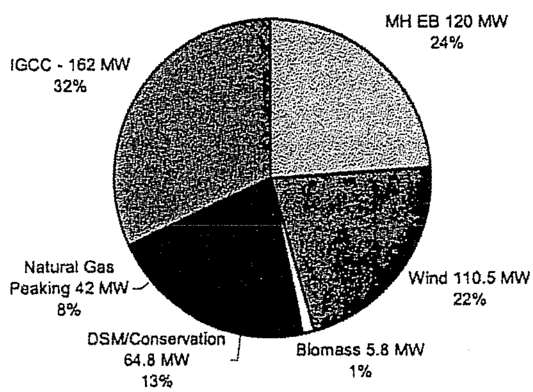
Figure 1
Preferred Resource Plan Resources
2006 - 2020



Based on the analysis in developing OTP's IRP, the second most cost-effective baseload resource to Big Stone Unit II was one of the purchase proposals received from MHEB. The deadline for exercising the MHEB transaction expired in 2004. Because Big Stone Unit II was more cost-effective, OTP did not attempt to negotiate an extension to the MHEB transaction beyond the 2004 expiration date. However, for purposes of the analysis done for this report, MHEB granted approval for OTP to use the cost and economic terms of MHEB's original proposal as a budgetary approximation with the explicit caveat that MHEB is under no obligation to offer those terms to OTP.

The alternative resource plan for OTP if Big Stone Unit II was not constructed is shown below in Figure 2.

Figure 2
Alternate Resource Plan Resources
2006 - 2020



Over the study period of the IRP, the expansion model selected a variety of resource and DSM alternatives beyond the 120 MW represented by either the Big Stone Unit II or MHEB purchase. The expansion model also selected wind, gas and IGCC resource options. The in-service date for the IGCC and wind resources selected by the model is 2018

Conservation has been identified as part of the company's preferred resource plan (Otter Tail Power Company Application for Resource Plan Approval 2006 – 2020, submitted July 1, 2005, Docket No. E017/RP-05-968). Approximately 13% or more of the capacity needs in that resource plan are identified as coming from conservation and DSM measures.

While OTP is a winter peaking utility, its baseload capacity needs are being driven by forecasted summer season capacity deficits that exceed its forecasted winter season capacity deficits. Knowing this, the company began pursuing projects and rates a number of years ago to increase its ability to manage its summer peak demand. This included typical programs such as cycling of central air conditioners in return for a customer incentive per month. In addition, rate modifications have been recently approved and plans are underway to include cycling cooling load in the summer that historically has not been controlled. Additional programs that historically have not been cost-effective due to summer demand and energy savings are now yielding cost-effective potential and are being either studied or launched. Primarily these programs target summer cooling loads that continue to grow. The company believes this prudent yet resourceful plan points to its historical diligence in aggressively pursuing demand-side and conservation opportunities.

The projected incremental annual DSM energy savings in the company's preferred plan over the 2006-2019 planning period covered by the company's 2005 resource plan are typically in the 8,000,000 kWh to 9,000,000 kWh range. As a comparison, the company expects to receive about 900,000,000 kWh annually from its 116 MW share of Big Stone Unit II. The projected incremental summer DSM demand savings associated with the energy savings identified above are projected to be about 1.5 MW each year. Achieving the level of energy and demand savings necessary to replace the annual energy and capacity the company expects to receive from Big Stone II simply is not practical or economically viable.

OTP would pursue the same aggressive levels of demand-side and conservation opportunities under the alternative plan presented in this analysis as it would for its preferred plan that includes Big Stone Unit II. While conservation and demand-side management are important resources in the company's future, they are not an appropriate substitute for 116 MW of baseload resources in 2011.

Appendix K in the Application details the OTP demand-side management programs.

Central Minnesota Municipal Power Agency (CMMPA) - CMMPA members currently obtain a majority of their energy needs through energy-only contract purchases and spot market purchases that are based on regional system incremental pricing. On a total basis, energy-only contract purchases and spot market purchases are projected to supply approximately 70% of CMMPA member energy needs through 2008. The balance of energy resources for CMMPA is comprised of approximately 17% from hydro and planned wind powered resources, 5% from a firm capacity and energy purchase, and 6% from self-generation resources, primarily diesel units.

Many of CMMPA members have contracts with Xcel Energy for supplying all or part of their energy requirements that will expire in the next one to five years. CMMPA members currently do not own any baseload coal resources and are in the process of beginning to build their own generation resource portfolios that will include baseload coal resources to reduce their exposure to the volatility of market rates and provide for fuel diversity.

CMMPA directed a power supply analysis to identify a projected range of baseload resources that each member could effectively utilize. The analysis also identified an amount of baseload coal resources that was projected to be more economical when compared to a gas-fired combined cycle alternative based on a projected range of natural gas prices.

The majority of the CMMPA members chose to add baseload coal resources. This alternative increases each member's fuel diversity. Historically, the price of coal has been significantly less volatile than gas and oil. One of CMMPA's strategies is to diversify its baseload requirements between two or three different baseload coal resources to provide diversity in fuel contracts, rail contracts, and shaft diversity. CMMPA is also trying to minimize future transmission delivery constraints. Other than a 13 MW unit power purchase from Nebraska City #2 unit scheduled to be in service in 2009, CMMPA members have no other baseload coal resources.

If Big Stone Unit II wete not built, CMMPA would look to continue to purchase energy from the market, although this would further expose its members to projected increased market prices and market volatility. CMMPA is not aware of any other opportunities in the MAPP region to meet its baseload coal requirements. As a group, CMMPA members are projected to need additional capacity by 2013. Delaying Big Stone Unit II by three years or more would require CMMPA members to purchase market capacity or install even more peaking generation.

In addition to purchases of hydro and wind energy, CMMPA members participate in energy conservation and efficiency programs. In accordance with Minnesota state law, CMMPA members are required to spend a portion of annual revenue dollars on conservation programs. CMMPA has served as a conduit and catalyst with its members to encourage benchmarking of conservation programs.

Appendix K of the Application details the conservation programs in place with CMMPA member utilities.

Great River Energy (GRE) – Through its integrated resource planning process, GRE has identified a need for baseload capacity and energy. If Big Stone Unit II is not constructed, GRE will seek to replace its 116 MW share with an equivalent share in the next baseload plant identified as a least-cost option for serving GRE's needs. GRE's overall share of the next least-cost option would need to be greater than 116 MW, however, since by the time the resource could be online, GRE's baseload needs are projected to be higher. GRE's most recent integrated resource plan shows a need for an additional 600 MW of baseload in the 2014 – 2016 timeframe.

GRE anticipates that the earliest any alternate baseload project could be available is 2014. In the interim years (2011 – 2013), GRE would need to replace both the capacity and energy it would have received from Big Stone Unit II. GRE has determined that its most prudent alternative to Big Stone Unit II would be to build a peaking plant to cover its capacity needs and a small portion of its energy needs, and supplement the additional energy needs by purchasing from the MISO short-term energy markets.

GRE notes that the alternative plan presented here is limited primarily to a supply-side plan. This does not reflect a lack of commitment to demand-side alternatives. Rather, GRE's selection of DSM levels is more dependent on what is achievable based on technologies, incentives, customer participation, and state Conservation Improvement Program budgets. GRE and its members have targeted areas where the type of need has been greatest. For example, in the recent past, GRE's DSM emphasis has been on lowering its summer peak, which has been GRE's dominant pattern of growth and resource need. The result of those actions has been to sign up approximately one-third of eligible residential consumers to cycled air conditioning programs.

As the need for baseload resources has become more pronounced, as well as in response to changing state policies governing cooperative CIP programs. GRE has significantly increased its focus on conservation programs that have a pattern of energy savings closer to the shape of baseload. GRE's total savings attributable to these types of conservation programs for 2002 – 2004 were as follows: 73,909 MWh, 113,455 MWh, and 139,968 MWh, respectively. In contrast, GRE expects to receive nearly 900,000 MWh/year from its share of Big Stone Unit II. To put this in perspective, GRE would need to achieve new conservation savings at a level that would be approximately eight times its highest *total* energy annual savings for conservation to replace the annual energy output it expects to receive from Big Stone Unit II.

Further, the demand savings associated with conservation programs are lower than the capacity amounts associated with GRE's share of Big Stone II. Therefore, even if conservation could result in savings equivalent to the energy output of GRE's share of Big Stone Unit II, GRE would have a continued need for new capacity resources. Finally, because of GRE's continued and significant growth rate, even a scenario of enormous conservation savings would only result in delaying the need for new baseload energy and capacity, rather than replacing that need.[2]

GRE will continue to pursue all of the cost-effective programs available to it. As GRE reported in its 2005 Integrated Resource Plan and as part of future Conservation Improvement Program filings, GRE will also explore new and creative solutions to promote additional conservation and is receptive to specific suggestions on how to do so. However, at this time, conservation programs are currently unable to replace GRE's proposed ownership interest of Big Stone Unit II.

Appendix K in the Application details the demand-side management programs in place with GRE member utilities.

Heartland Consumers Power District (Heartland) - Heartland currently purchases over half of its baseload resources under power purchase agreements. By the scheduled 2011 in-service date of Big Stone Unit II, over 100 MW will be provided through power purchase agreements. All of the agreements, however, will have expired by the end of 2013. Heartland is participating in the proposed Big Stone Unit II because it is

[2] GRE's share of Big Stone II represents a little over one year of demand growth and approximately three years of energy growth.

the least cost option to replacing the purchase power agreements. Heartland has other resource options it is pursuing, to replace the balance of its resource needs. If Big Stone Unit II was not built, Heartland would attempt to rely on purchases of energy from the market to replace its proposed ownership allocation of the Big Stone Unit II resource. It would continue to participate in the market until it was able to participate in another, lower cost resource option, most likely another pulverized coal baseload generation project

Heartland, as a supplemental wholesale power supplier, works with its wholesale customers to promote demand-side management programs, and at this time allows its customers to implement demand-side management alternatives. Heartland promotes and assists its wholesale customers with their demand-side management programs. As discussed in Appendix K of the Application, Heartland's customers have implemented, to varying degrees, over fifteen different conservation and load management programs. Heartland plans to continue to assist its customers with evaluating and implementing their energy efficiency and conservation programs, maximizing the effectiveness of their load management strategies, and encouraging the improvement of their electric systems.

Appendix K in the Application details the demand-side management programs in place with Heartland wholesale customer utilities.

Missouri River Energy Services (MRES) - The preferred alternative for MRES to meet its member resource needs is investment in 150 MW of Big Stone Unit II, combined with 40 MW of wind energy and 180 MW of natural gas simple-cycle combustion turbines (CT). The Big Stone Unit II investment would serve both the load of MRES members and the 40 MW obligation to the city of Hutchinson, Minnesota. MRES has a contract with the Hutchinson Municipal Utilities Commission under which MRES has the responsibility to provide 40 MW of capacity and associated energy to Hutchinson from Big Stone Unit II.

MRES estimated the least-cost alternative to utilizing Big Stone Unit II as part of its 2006-2020 Resource Plan. The analysis appears in the MRES 2006-2020 Resource Plan, Docket No. ET10/RP-05-1102.[3] The alternative plan was a combination of 60 MW of coal resource from a future Resource Coalition (RC) unit combined with 180 MW of CT units. The Resource Plan did not specifically include the proposed Hutchinson obligation.

The RC was formed to capture the economies of scale necessary to provide low-cost reliable power and to reduce the risks associated with developing a single large resource. By joining with other companies in a partial ownership of two or three large coal plants, rather than building a single MRES unit, the risks associated with a single unit being out of service are reduced. The RC has explored sites in North Dakota, South Dakota and Iowa to build up to a 600 MW coal-based facility and potentially 100 MW of wind energy. After completing transmission and siting studies, members of the coalition will make decisions regarding their individual participation in the project, which could be available in the 2014 timeframe. The best estimate is that the RC site will be somewhere in eastern South Dakota. Transmission studies are only just starting for the RC project.

For purposes of this response to the Order, MRES developed a refinement to the MRES alternative plan so as to include enough renewable resources in the alternative to meet the REO and to serve the 40 MW Hutchinson load. The least-cost result showed that obtaining 90 MW from the proposed RC plant combined with 40 MW of wind (accredited at an estimated 6 MW) and 225 MW of CT units was the preferred alternative plan for use in this response to the Order. Since the proposed RC project would not be available until at least 2014, MRES would need to build 90 MW of CT units prior to 2014 in order to meet predicted shortages in capacity. MRES would also need to obtain an additional 135 MW of CT units between 2016 and 2020 to meet the growing capacity and peaking energy requirements through the end of the study period.

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[3] Presently, MRES is undertaking capacity expansion modeling as part of its Resource Plan and intends to submit the results of that additional analysis to the Commission by approximately April 1, 2006. The capacity expansion modeling proposes to, among other things, allow renewable resources such as wind and demand-side management to compete directly on the basis of costs with more traditional supply-side resources, including the proposed Big Stone Unit II.

Table 4

No Big Stone Unit II Expansion Plan for MRES			
Year	Unit	Accredited MW	Unit Type
2007	Wind	6	Renewable - Wind (40 MW nameplate)
2011	CT	90	Combustion Turbine
2014	RC	90	Coal
2016	CT	45	Combustion Turbine
2017	CT	45	Combustion Turbine
2020	CT	45	Combustion Turbine

MRES, as a wholesale supplier, relies primarily on its member utilities to implement demand-side management programs. The MRES membership has an extensive history of DSM activities. For example, during the 1980's, power rates from MRES were nearly twice today's rates, providing a strong incentive for members to invest in DSM equipment and programs. MRES staff acquired recent reports (for the years 2002 to 2005) from the member cities and compiled data regarding these programs. Based on these reports, it is estimated that MRES's member communities, as a whole, spend approximately $1.96 million per year on DSM programs and save roughly 57 MW and 22,400 MWh annually.

In contrast, MRES expects to receive over 780,000 MWh per year from its share of Big Stone Unit II. To put this in perspective, MRES member communities would need to achieve new conservation savings at a level that would be over 30 times their *total* energy annual savings for conservation to replace the annual energy output MRES expects to receive from Big Stone Unit II.

Each member also undergoes extensive integrated resource plan (IRP) analysis as part of their periodic IRP filings with the Western Area Power Administration (WAPA). The IRP requires members to perform an analysis of applicable DSM, supply-side and renewable energy programs, and resulted in specific DSM program recommendations for each member. MRES continues to assist its members with preparation of the WAPA IRP filings and with meeting the annual reporting requirements.

In addition, the Minnesota members are required to meet a minimum spending requirement of 1.5% of their gross operating revenue on energy conservation improvement program (CIP) activities. Each Minnesota member files an annual report with the state, showing the details of their DSM expenditures for the year.

MRES supports the efforts of the members to evaluate load management and other DSM opportunities. At least annually, each member representative receives a report of the community's hourly load pattern, seasonal load duration curves, and current and projected costs for the next five years. MRES staff also regularly assists consultants in preparing and reviewing DSM studies on behalf of members.

From 1992 through 1999, MRES has also helped its members provide over 125,000 trees under the Tree Power Program sponsored by the American Public Power Association. The trees were planted in the member communities to enhance the environment and reduce summertime energy usage.

In addition to the DSM assistance that MRES provides its members, MRES also actively engages in its own DSM-related activities, providing programs and services to member communities and their commercial and industrial customers. These programs include digital infrared thermal scanning of electrical systems, ultrasonic leak detection of compressed air systems, motor efficiency and power quality analysis, Questline® consumer energy service, and other efficiency programs.

Montana-Dakota Utilities (Montana-Dakota) - Montana-Dakota has identified its next best alternative to Big Stone Unit II as a lignite-fired plant currently proposed to be built near Gascoyne, North Dakota, referred to as the Lignite Vision 21 (LV 21) project. The LV 21 project is proposed to be a sub-critical, circulating fluidized bed, steam-electric generating station designed for baseload operation, with a nominal net power output of 175 MW.

In addition to the existing demand-side management programs detailed in Appendix K of the Application, for its 2005 IRP Montana-Dakota plans to implement an additional 6.5 MW of demand-side management and conservation measures during the 2006-2010 time period, such as high efficiency residential air-conditioning and commercial lighting retrofit programs. These programs are planned regardless of which baseload alternative, Big Stone Unit II or the LV 21 project, is constructed, and they will be implemented before the expected in-service date of Big Stone Unit II.

Appendix K in the Application details the demand-side management programs in place with Montana-Dakota.

Southern Minnesota Municipal Power Agency (SMMPA) - SMMPA's need for additional resources occurs in 2008. SMMPA's 2003 Integrated Resource Plan (IRP) identified a need for a 53 MW participation in a combined cycle plant in 2008 and a 53 MW participation in a pulverized coal plant in 2013. High gas price sensitivities in that IRP shifted the next resource to the 53 MW participation in the pulverized coal facility in 2008 followed by another 53 MW pulverized coal plant participation in 2013. Subsequent to the acceptance of that plan, SMMPA has been working on the implementation of that strategy. However, because Big Stone Unit II, SMMPA's preferred option, is not expected to come on line until 2011, SMMPA will seek to bridge the gap with an energy and capacity market purchase.

Before committing to participation in Big Stone Unit II, SMMPA developed a series of EGEAS models as a check to Big Stone Unit II participation. That modeling evaluated (1) a 100 MW share of a pulverized coal plant, (2) a 50 MW share of a pulverized coal plant (based on Big Stone Unit II actual numbers), (3) a 50 MW combined cycle plant, and (4) a 50 MW combustion turbine. That modeling also included a 50 MW purchased power agreement, wind power and landfill gas. All models fully accepted available DSM.

For the purposes of responding to the information sought in the Order, SMMPA re-ran the modeling of the units listed above. These new runs included updated fuel costs that were incorporated in November of 2005 in preparation for SMMPA's 2006 budget. Natural gas costs were based upon the New York Mercantile Exchange (NYMEX) adjusted for location, and coal costs reflected a 39% increase in SMMPA's coal costs to be effective January 1, 2006.

The 100 MW share of a pulverized coal plant was the least cost alternative, followed by the 50 MW share of a pulverized coal plant, followed by the 50 MW gas alternatives.

No coal plant projects are currently available that provide a 100 MW share to SMMPA. Although the next lower cost option included a 50 MW share, in reality, SMMPA is only able to acquire 47 MW of Big Stone Unit II. The mix of resources in these alternative futures is shown in the Tables 5 and 6.

Table 5

50 MW PULVERIZED COAL EXPANSION PLAN				
				RETIREMENTS
YEAR	UNIT	MW	UNIT TYPE	MW
2006	Landfill Gas	2.4	Renewable	
2007	Wind	3.3	Renewable	
2008	Wind	3.3	Renewable	
2008	Split Rock		Firm Purchase	45
2008	Split Rock II	50	Firm Purchase	
2009	Wind	3.3	Renewable	
2010	Landfill Gas	2.4	Renewable	
2011	BSII	50	Coal	
2011	Wind	3.3	Renewable	
2013	Wind	3.3	Renewable	
2014	Wind	3.3	Renewable	
2015	Wind	3.3	Renewable	
2018	Split Rock II	50	Firm Purchase	
2023	Split Rock II	50	Firm Purchase	
2028	Split Rock II	50	Firm Purchase	

Table 6

COMBUSTION TURBINE 50 MW EXPANSION PLAN				
				RETIREMENTS
YEAR	UNIT	MW	UNIT TYPE	MW
2006	Landfill Gas	2.4	Renewable	
2007	Wind	3.3	Renewable	
2008	Wind	3.3	Renewable	
2008	Split Rock		Firm Purchase	45
2008	Split Rock II	50	Firm Purchase	
2009	Wind	3.3	Renewable	
2010	Landfill Gas	2.4	Renewable	
2011	CT	50	Combustion Turbine	
2011	Wind	3.3	Renewable	
2013	Wind	3.3	Renewable	
2014	Wind	3.3	Renewable	
2015	Wind	3.3	Renewable	
2018	Split Rock II	50	Firm Purchase	
2023	Split Rock II	50	Firm Purchase	
2028	Split Rock II	50	Firm Purchase	

All of the above alternative expansion plans fully utilized SMMPA DSM programs. SMMPA members were early adopters in cycling technologies and load control and have significant penetration in those programs. Beginning in 1991 SMMPA has been designing and assisting its members with the implementation of conservation initiatives to complement those load control efforts. Although SMMPA members' customer base is relatively small, about 106,000 retail customers in total, SMMPA and its members have been aggressive in designing DSM programming. SMMPA was recognized nationally in 2002 and 2003, winning National Energy Star Awards from the U.S. Environmental Protection Agency and the Department of Energy. ~~Table 7 provides~~ the total DSM savings achieved from SMMPA's members over the past several years. is indicated in the following table:

~~Table 7~~

Total DSM Savings

Year	Demand Savings (MW)	Energy Savings (MWh)
2002	27	12,387
2003	28	13,416
2004	32	19,407

SMMPA continues to look for, evaluate and add new conservation initiatives. Such DSM efforts will be effective at reducing the size and/or delaying the timing of additional SMMPA resources. SMMPA's DSM resources are important in deferring the investment in new generation facilities, but they are not a replacement. The expansion plan outlined in the 2003 IRP included approximately 200,000 MWhs of DSM in 2011. Additionally SMMPA needs approximately another 340,000 MWhs, of energy to be provided by the 50 MW supply side options described above.

Appendix K of the Application details the demand-side management programs in place with SMMPA member utilities.

PART B

Including the environmental cost values adopted by the Commission, compare and contrast the costs of the resulting overall generation and demand-side management alternative (i.e., the combination of all seven sub-alternatives and associated transmission improvements) with the Big Stone projects (i.e., Big Stone Unit II plus the preferred transmission alternative provided in the application).

Revenue Requirements

Each Applicant developed annual revenue requirements from 2011 to 2020 for the resource scenarios that included Big Stone Unit II and their next best alternative. The annual costs provide the fixed and variable costs associated with the capital investment, operations and maintenance, fuel, market purchases, demand-side management programs, transmission interconnection and other costs associated with the two resource scenarios. Annual revenue requirements were determined by some Applicants on a total revenue requirements basis, while others provided an incremental projection of annual revenue requirements. A total revenue requirements approach provides all of the revenue requirements for a utility, including those that are required regardless of the resource scenario selected. An incremental approach provides only those costs that are different between the resource scenarios. Since the comparison of the options includes a subtraction of the two net present values associated with the plans, those costs that are constant become netted out of the difference. As a result, either approach provides the same results when comparing the difference in revenue requirements between the two scenarios (i.e., Big Stone Unit II and the next best alternative).

The assumptions for the different input variables used by each Applicant are based on the Applicant's forecasts for each input variables. Each Applicant developed the projection for the input variables such as fuel and market energy costs. Information about the various input assumptions for each of the Applicant's resource expansion planning models is unique to each Applicant. Annual costs were totaled for both resource scenarios to compare the "with" and "without" scenarios as set forth by the Order.

For the alternatives that include solid fuel resources, costs for SO_2 and mercury emissions have been accounted for in the annual revenue requirements as fixed and variable costs. As recognized by the Commission, these emissions are not considered an externality since the costs for limiting these emissions is internalized in the capital and operating costs. Costs for the Commission's list of externalities are developed separately in the next section. In order to review the revenue requirements of the two resource scenarios without externalities considered, the Applicants' individual revenue requirements with and without Big Stone Unit II were totaled. Table 8 provides the annual revenue requirements for the two resource scenarios for each of the Applicants.

Due to the different capital structures of the Applicants, each Applicant uses a slightly different discount factor when creating a net present value. Therefore, the individual net present values of each Applicant could not be summed and it was necessary to have each Applicant provide the annual revenue requirements associated with its scenarios. In order to arrive at a common net present value of revenue requirements, a common discount factor was applied to the sum of the individual Applicant's annual revenue requirements for the resource scenarios with and without Big Stone Unit II. A discount factor of eight percent was selected as a reasonable basis for calculating the net present value in Table 8 and elsewhere in this submittal. Unless otherwise noted, all NPVs presented in this filing are in 2011 dollars.

Table 8
Annual Revenue Requirements for Futures with and without Big Sto
2011 to 2020
($000s)

	2011	2012	2013	2014	2015	2016	2017	
BSPII OPTION								
CMMPA								
HEARTLAND								
MRES [1]								
OTP								
SMMPA								
MDU								
GRE [2]								
Total Annual Costs	$ 1,073,416	$ 850,795	$ 881,065	$ 926,098	$ 926,735	$ 1,004,143	$ 967,139	$ 1,148
Net Present Value [3]	$6,523,898							
BEST INDIVIDUAL ALTERNATIVE OPTION								
CMMPA								
HEARTLAND								
MRES								
OTP								
SMMPA								
MDU								
GRE [2]								
Total Annual Costs	$ 983,468	$ 953,933	$ 989,313	$ 1,209,486	$ 1,027,284	$ 1,072,944	$ 1,114,205	$ 1,224
Net Present Value [3]	$7,193,039							
Benefit of BSII over Alternate	$669,141							

Notes:
[1] MRES costs provided include the capacity provided for Hutchinson, MN.
[2] GRE costs provided are incremental revenue requirements, while other utilities' costs are total revenue requirements for the two futures.
[3] Net Present Value calculation is based on an 8 percent discount rate in 2011 dollars

As shown in Table 8, using Big Stone Unit II to meet the Applicants' obligations beginning in year 2011 is $669,141,000 less expensive on a net present value basis than the alternative resource scenarios that do not include Big Stone Unit II. This represents a savings of approximately 9 percent below the projected net present values of the scenarios without Big Stone Unit II.

Externality Cost Implications

The Order required that the Applicants examine externalities associated with Big Stone Unit II and the alternative resource scenarios. The externality values for the Big Stone Unit II scenarios were calculated using the expected dispatch of the units involved with the expected emission rates for each externality applied, be they based on liquid, solid, or gas fuel, or on market purchases. The externalities for the alternative resource scenario were developed by using emission rates for alternative solid fuel units, gas units and market purchases. The emission rates for market purchases were derived using the regional average emission factors shown in Table 9.

Table 9
Regional Average Emission Factors
(MPCA/PUC Environmental Disclosure Brochure Data)

Emission Rates	lb/kWh	
NOx (1)	0.0004	(1) PVS 2004 Avg. from Env. Disclosure
CO (2)	0.00075	(2) Used new Natural Gas CT values
PM10 (1)	0.00033	
Lead (2)	0.0000	
CO_2 (1)	1.839	
SO_2 (1)	0.0055	

OTP - The best alternative resource option for OTP included purchases from MHEB. The energy from MHEB is generated primarily from hydro-electric resources for which no externality values presently exist. Therefore, no environmental costs are considered for the energy from the MHEB purchases.

CMMPA – CMMPA's alternative to Big Stone Unit II energy is purchases from the market. For the MISO market, power and energy from the proposed Big Stone Unit II is assumed to displace energy produced by gas and less efficient coal units. Average emissions rates of market resources were used to project the cost of environmental externalities between the two alternatives. For the purposes of preparing this analysis, it was assumed that all of the resources in the alternate resource scenario are located within Minnesota.

GRE - GRE's alternative to Big Stone Unit II included market purchases and the use of a simple cycle combustion turbine until an assumed participation in a coal unit assumed to be operational starting in 2014 became available. All of the resources in the alternative resource scenario are assumed to be located within Minnesota.

Heartland - Heartland's alternative to Big Stone Unit II consists of market purchases for its capacity and energy needs. All of the resources in the alternative resource scenario are assumed to be located within Minnesota.

MRES – The MRES alternative to Big Stone Unit II included coal and natural gas capacity. The 150 MW share of Big Stone Unit II, along with 180 MW of gas turbine units, would be replaced in the alternative option with 90 MW of Resource Coalition coal capacity and associated energy and 225 MW of gas turbine capacity. The next gas turbine addition, of 90 MW in 2016, would need to be moved up by five years to 2011 in the alternative plan.

The alternative option would reduce the available energy from coal, while increasing reliance on natural gas. All of the resources in the alternate future are assumed to be outside of Minnesota, but within 200 miles of the Minnesota border.

Montana-Dakota - Montana-Dakota's alternative to Big Stone Unit II is the construction of the Lignite Vision 21 plant proposed to be built near Gascoyne, North Dakota, which is farther than 200 miles from the Minnesota border. The externalities associated with this project would not normally be considered in an assessment of externalities in Minnesota. However, because the externalities for the combined Big Stone Unit II resource scenario include those for Montana-Dakota's share of Big Stone Unit II, the externalities associated with the LV21 Project are also included for comparative purposes.

SMMPA – SMMPA's analysis shows that the next best alternative to Big Stone Unit II is one that uses approximately 50 MW of combustion turbines and market purchases. The emission rates were based on typical emission rates for the size units considered. All of the resources in the alternative resource scenario are assumed to be located within Minnesota.

Externality Quantity Development

To develop the cost of externalities for addition to the costs of the various resource plans, the weights of the externalities from each resource within each of the Applicants scenarios must first be determined. These externality quantities from each Applicants' resource scenario were then converted to the total weights for the scenarios with Big Stone Unit II and those without Big Stone Unit II for use in the application of the Commission's per unit costs. The externality weight information for the scenarios including Big Stone Unit II and the alternative resource scenarios are summarized in Table 10. Table 10 includes the total estimates of the incremental externality weights for the emissions associated with each of the Applicants' scenarios. Details of the development of the incremental externality weights are included in Appendix A to this report.

Under the Commission's standard approach to valuing externalities, the CO_2 externality is not applied for units outside of Minnesota. However, the Applicants have provided the impact of CO_2 for the incremental units considered in the plans that are outside of Minnesota to provide a more complete picture of the overall impacts across the full range of CO_2 that could be considered connected to the decisions about the scenarios. Weights for this externality are shown for the Applicants' resource scenarios for resources located within and outside Minnesota.

Table 10
Incremental Externality Emissions Summary
(Tons)

CO_2 EMISSIONS INSIDE MN ONLY

Annual Total Emissions		2011	2012	2013	2014	2015	2016	2017	2018
NOx	BSPII Option	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,0
	Alternate	1,389.20	1,574.54	1,533.98	1,510.18	1,610.88	1,538.25	1,492.41	1,4
CO_2	BSPII Option	25,014.93	0.00	0.00	0.00	0.00	0.00	0.00	
	Alternate	1,100,865.02	1,235,387.03	1,220,291.69	1,333,844.93	1,342,325.05	1,326,524.00	1,333,749.72	1,315,4
Pb	BSPII Option	0.17	0.17	0.17	0.17	0.17	0.17	0.17	
	Alternate	0.12	0.12	0.12	0.11	0.12	0.22	0.12	
CO	BSPII Option	2,187.78	2,172.03	2,172.66	2,172.03	2,172.03	2,172.03	2,172.03	2,1
	Alternate	1,953.95	2,126.44	2,092.08	2,683.90	2,806.98	2,787.76	2,802.98	2,8
PM_{10}	BSPII Option	655.27	651.61	651.61	651.61	651.61	651.61	651.61	6
	Alternate	973.76	1,074.00	1,106.44	1,236.40	1,328.42	1,354.65	1,387.58	1,4
Hg	BSPII Option	0.05	0.05	0.05	0.05	0.05	0.05	0.05	
	Alternate	0.20	0.20	0.20	0.21	0.21	0.21	0.21	
SO_2	BSPII Option	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,0
	Alternate	13,273.48	14,630.36	14,476.33	14,316.32	13,129.27	14,260.19	14,412.81	14,4

CO_2 EMISSIONS INSIDE & OUTSIDE OF MN

Annual Total Emissions		2011	2012	2013	2014	2015	2016	2017	2018
NOx	BSPII Option	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,0
	Alternate	1,389.20	1,574.54	1,533.98	1,510.18	1,610.88	1,538.25	1,492.41	1,4
CO_2	BSPII Option	4,482,023.55	4,457,008.61	4,457,008.61	4,474,014.19	4,457,008.61	4,457,008.61	4,473,668.73	4,460,6
	Alternate	3,175,693.50	3,624,434.92	3,552,201.88	3,913,217.38	4,052,892.26	4,006,337.82	4,072,925.69	4,071,6
Pb	BSPII Option	0.17	0.17	0.17	0.17	0.17	0.17	0.17	
	Alternate	0.12	0.12	0.12	0.11	0.12	0.22	0.12	
CO	BSPII Option	2,187.78	2,172.03	2,172.66	2,172.03	2,172.03	2,172.03	2,172.03	2,1
	Alternate	1,953.95	2,126.44	2,092.08	2,683.90	2,806.98	2,787.76	2,802.98	2,8
PM_{10}	BSPII Option	655.27	651.61	651.61	651.61	651.61	651.61	651.61	6
	Alternate	973.76	1,074.00	1,106.44	1,236.40	1,328.42	1,354.65	1,387.58	1,4
Hg	BSPII Option	0.05	0.05	0.05	0.05	0.05	0.05	0.05	
	Alternate	0.20	0.20	0.20	0.21	0.21	0.21	0.21	
SO_2	BSPII Option	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,0
	Alternate	13,273.48	14,630.36	14,476.33	14,316.32	13,129.27	14,260.19	14,412.81	14,4

Externality Cost Development

The per unit costs to be charged against each externality were taken from the Commission's April 27, 2005 "Notice of Updated Environmental Externality Values." (See Appendix B to this report) Table 11 includes the range of externality values using the Commission's most recent updated values, which have been adjusted by the Consumer Price Index (CPI) to 2004. Because the externality cost is adjusted each year by the CPI and the weights for externalities in Table 9 are projected from 2011 to 2020, the 2004 cost values need to be escalated to reflect their future nominal values over the period of 2011 to 2020. In order to estimate these future nominal values, the externality cost values have been escalated from the 2004 values by three percent annually to reflect a nominal adjustment to the CPI.

The values for SO_2 and Hg are included as weights in Table 11 only and are valued in Table 12. In accordance with the Commission's approach to valuing these externalities, the cost of these externalities have been included in the capital and operating costs of the resources for the annual revenue requirements in Table 8.

Table 11 summarizes the NPVs of annual revenue requirements for the individual resource alternative for the Applicants with and without externalities considered. The NPVs for the Base are those developed in Table 8 above. The High Ext, Low Ext and All CO_2 NPVs are taken from the respective NPV results in Table 10.

The results indicate that the use of Big Stone Unit II capacity and energy in the Applicants' resource scenarios provides a lower amount of revenue requirements, ranging from a low of $653,531,000 in the All CO_2 case to a high of $718,185,000 in the High Ext case, than a future without Big Stone Unit II. These values represent NPV savings of from 8.55 to 9.51 percent through use of the Big Stone Unit II in the Applicants' scenarios over the NPV costs without Big Stone Unit II.

Table 11
Incremental Externality Cost Summary

			2004$ [1]	2011	2012	2013	2014	2015	2016	2017	20
Annual Unit Costs of Externalities											
	NOx	High	$ 120.00	$ 147.58	$ 152.01	$ 156.57	$ 161.27	$ 166.11	$ 171.09	$ 176.22	$ 181.
		Low	$ 21.00	$ 25.83	$ 26.60	$ 27.40	$ 28.22	$ 29.07	$ 29.94	$ 30.84	$ 31.
	CO_2	High	$ 3.64	$ 4.48	$ 4.61	$ 4.75	$ 4.89	$ 5.04	$ 5.19	$ 5.35	$ 5.
		Low	$ 0.35	$ 0.43	$ 0.44	$ 0.46	$ 0.47	$ 0.48	$ 0.50	$ 0.51	$ 0.
	Pb	High	$ 526.00	$ 646.91	$ 666.32	$ 686.31	$ 706.90	$ 728.11	$ 749.95	$ 772.45	$ 795.
		Low	$ 472.00	$ 580.50	$ 597.92	$ 615.85	$ 634.33	$ 653.36	$ 672.96	$ 693.15	$ 713.
	CO	High	$ 0.48	$ 0.59	$ 0.61	$ 0.63	$ 0.65	$ 0.66	$ 0.68	$ 0.70	$ 0.
		Low	$ 0.25	$ 0.31	$ 0.32	$ 0.33	$ 0.34	$ 0.35	$ 0.36	$ 0.37	$ 0.
	PM_{10}	High	$ 1,005.00	$ 1,236.02	$ 1,273.10	$ 1,311.30	$ 1,350.64	$ 1,391.16	$ 1,432.89	$ 1,475.88	$ 1,520.
		Low	$ 660.00	$ 811.72	$ 836.07	$ 861.15	$ 886.98	$ 913.59	$ 941.00	$ 969.23	$ 998.
CO2 EMISSIONS INSIDE MN ONLY											
Annual Total Costs of Externalities (High)											
	NOx	BSPII Option		$ 160,279	$ 165,088	$ 170,041	$ 175,142	$ 180,396	$ 185,808	$ 191,382	$ 197,1
		Alternate		$ 205,025	$ 239,349	$ 240,179	$ 243,546	$ 287,581	$ 263,182	$ 262,998	$ 261,5
	CO_2	BSPII Option		$ 111,985	$ -	$ -	$ -	$ -	$ -	$ -	$
		Alternate		$ 4,928,287	$ 5,696,423	$ 5,795,622	$ 6,524,977	$ 6,763,454	$ 6,884,354	$ 7,129,509	$ 7,242,6
	Pb	BSPII Option		$ 111	$ 114	$ 118	$ 121	$ 125	$ 129	$ 133	$ 1
		Alternate		$ 75	$ 78	$ 80	$ 79	$ 87	$ 164	$ 92	$ 1
	CO	BSPII Option		$ 1,292	$ 1,321	$ 1,361	$ 1,401	$ 1,443	$ 1,486	$ 1,531	$ 1,5
		Alternate		$ 1,153	$ 1,293	$ 1,310	$ 1,731	$ 1,865	$ 1,906	$ 1,976	$ 2,0
	PM_{10}	BSPII Option		$ 809,930	$ 829,567	$ 854,454	$ 880,087	$ 906,490	$ 933,684	$ 961,695	$ 990,5
		Alternate		$ 1,203,594	$ 1,367,315	$ 1,450,867	$ 1,669,920	$ 1,848,044	$ 1,941,064	$ 2,047,901	$ 2,129,0
Total Annual Costs for all Externalities		BSPII Option		$ 1,083,598	$ 996,089	$ 1,025,973	$ 1,056,751	$ 1,088,454	$ 1,121,107	$ 1,154,741	$ 1,189,3
		Alternate		$ 6,338,134	$ 7,304,458	$ 7,488,059	$ 8,440,253	$ 8,881,031	$ 9,090,672	$ 9,442,475	$ 9,635,4
NPV of Externalities		BSPII Option		$7,409,451.70							
		Alternate		$56,454,015.22							
Annual Total Costs of Externalities (Low)											
	NOx	BSPII Option		$ 28,049	$ 28,890	$ 29,757	$ 30,650	$ 31,569	$ 32,516	$ 33,492	$ 34,4
		Alternate		$ 35,879	$ 41,886	$ 42,031	$ 42,621	$ 46,827	$ 46,057	$ 46,025	$ 45,7
	CO_2	BSPII Option		$ 8,755	$ -	$ -	$ -	$ -	$ -	$ -	$
		Alternate		$ 473,874	$ 547,733	$ 557,271	$ 627,402	$ 650,332	$ 661,957	$ 685,530	$ 696,4
	Pb	BSPII Option		$ 100	$ 103	$ 106	$ 109	$ 112	$ 115	$ 119	$ 1
		Alternate		$ 67	$ 70	$ 72	$ 71	$ 78	$ 147	$ 82	$ 1
	CO	BSPII Option		$ 673	$ 688	$ 709	$ 730	$ 752	$ 774	$ 797	$ 8
		Alternate		$ 601	$ 673	$ 682	$ 902	$ 971	$ 994	$ 1,029	$ 1,0
	PM_{10}	BSPII Option		$ 531,895	$ 544,790	$ 561,134	$ 577,968	$ 595,307	$ 613,168	$ 631,561	$ 650,5
		Alternate		$ 790,420	$ 897,938	$ 952,808	$ 1,096,864	$ 1,213,641	$ 1,274,729	$ 1,344,890	$ 1,398,1
Total Annual Costs for all Externalities		BSPII Option		$ 569,471	$ 574,471	$ 591,705	$ 609,456	$ 627,740	$ 646,572	$ 665,969	$ 685,9
		Alternate		$ 1,300,841	$ 1,488,301	$ 1,552,865	$ 1,767,859	$ 1,911,649	$ 1,983,884	$ 2,077,558	$ 2,141,5
NPV of Externalities		BSPII Option		$4,221,864.89							
		Alternate		$12,100,460.31							

Table 11
Incremental Externality Cost Summary (Continued)

			2004$	2011	2012	2013	2014	2015	2016	2017	201
Annual Unit Costs of Externalities											
	NOx	High	$ 120.00	$ 147.58	$ 152.01	$ 156.57	$ 161.27	$ 166.11	$ 171.09	$ 176.22	$ 181.5
		Low	$ 21.00	$ 25.83	$ 26.60	$ 27.40	$ 28.22	$ 29.07	$ 29.94	$ 30.84	$ 31.7
	CO_2	High	$ 3.64	$ 4.48	$ 4.61	$ 4.75	$ 4.89	$ 5.04	$ 5.19	$ 5.35	$ 5.5
		Low	$ 0.35	$ 0.43	$ 0.44	$ 0.46	$ 0.47	$ 0.48	$ 0.50	$ 0.51	$ 0.5
	Pb	High	$ 528.00	$ 646.91	$ 666.32	$ 686.31	$ 706.90	$ 728.11	$ 749.95	$ 772.45	$ 795.6
		Low	$ 472.00	$ 580.50	$ 597.92	$ 615.85	$ 634.33	$ 653.36	$ 672.96	$ 693.15	$ 713.9
	CO	High	$ 0.48	$ 0.59	$ 0.61	$ 0.63	$ 0.65	$ 0.66	$ 0.68	$ 0.70	$ 0.7
		Low	$ 0.25	$ 0.31	$ 0.32	$ 0.33	$ 0.34	$ 0.35	$ 0.36	$ 0.37	$ 0.3
	PM_{10}	High	$ 1,005.00	$ 1,236.02	$ 1,273.10	$ 1,311.30	$ 1,350.64	$ 1,391.16	$ 1,432.89	$ 1,475.88	$ 1,520.1
		Low	$ 660.00	$ 811.72	$ 836.07	$ 861.15	$ 886.98	$ 913.59	$ 941.00	$ 969.23	$ 998.3
CO_2 EMISSIONS INSIDE & OUTSIDE OF MN											
Annual Total Costs of Externalities (High)											
	NOx	BSPII Option		$ 160,279	$ 165,088	$ 170,041	$ 175,142	$ 180,396	$ 185,808	$ 191,382	$ 197,12
		Alternate		$ 205,025	$ 239,349	$ 240,179	$ 243,546	$ 267,581	$ 263,182	$ 262,998	$ 261,50
	CO_2	BSPII Option		$ 20,064,858	$ 20,551,459	$ 21,168,003	$ 21,886,231	$ 22,457,134	$ 23,130,848	$ 23,913,829	$ 24,559,65
		Alternate		$ 14,216,757	$ 16,712,426	$ 16,870,737	$ 19,142,894	$ 20,420,949	$ 20,791,970	$ 21,771,672	$ 22,417,98
	Pb	BSPII Option		$ 111	$ 114	$ 118	$ 121	$ 125	$ 129	$ 133	$ 13
		Alternate		$ 75	$ 78	$ 80	$ 79	$ 87	$ 164	$ 92	$ 17
	CO	BSPII Option		$ 1,292	$ 1,321	$ 1,361	$ 1,401	$ 1,443	$ 1,488	$ 1,531	$ 1,57
		Alternate		$ 1,153	$ 1,283	$ 1,310	$ 1,731	$ 1,865	$ 1,908	$ 1,976	$ 2,04
	PM_{10}	BSPII Option		$ 809,830	$ 829,567	$ 854,454	$ 880,067	$ 906,490	$ 933,684	$ 961,695	$ 990,54
		Alternate		$ 1,203,594	$ 1,367,315	$ 1,450,867	$ 1,669,920	$ 1,848,044	$ 1,941,064	$ 2,047,901	$ 2,129,07
Total Annual Costs for all Externalities		BSPII Option		$ 21,036,471	$ 21,547,548	$ 22,193,975	$ 22,942,983	$ 23,545,588	$ 24,251,955	$ 25,068,570	$ 25,749,04
		Alternate		$ 15,626,604	$ 18,320,460	$ 18,563,173	$ 21,058,171	$ 22,538,525	$ 22,998,208	$ 24,084,638	$ 24,810,78
NPV of Externalities		BSPII Option		$158,270,030.33							
		Alternate		$142,660,447.32							

NOTES.
(1) CPI Adjustment estimated at 3 percent annually

2094

Table 12
NPVs of Futures with Externalities
($000s)

	BSUII Future	No BSUII Future	Difference	% Benefit of BSUII Over Alternate
Base	$6,523,898	$7,193,039	$ 669,141	9.30%
High Ext	$ 7,409	$ 56,454	$ 49,045	
Total	$ 6,531,308	$ 7,249,493	$ 718,185	9.91%
Low Ext	$ 4,222	$ 12,100	$ 7,879	
Total	$ 6,528,120	$ 7,205,139	$ 677,019	9.40%
All CO2	$ 158,270	$ 142,660	$ (15,610)	
Total	$ 6,682,168	$ 7,335,699	$ 653,531	8.91%

PART C

To the extent possible, discuss the comparative reliability of the resulting overall generation and demand-side alternative with that of the Big Stone projects.

The alternatives to Big Stone Unit II will have different considerations of reliability due to the variety of approaches used by the individual Applicants in meeting the portion of need – both capacity and energy – that the Big Stone Unit II and associated interconnection facilities would otherwise represent. As the Order recognizes, making comparisons with respect to a project such as Big Stone II, which has undergone extensive transmission study and modeling as part of the MISO interconnection process and a wide variety of alternative and independent resource scenarios that have not been identified or studied in as much detail, is difficult. Notwithstanding this difficulty, the following discusses the relative reliability of the competing resource scenarios.

Alternate Coal Unit Futures

The alternative resource scenarios of Montana-Dakota and MRES included two specific coal-fired resources: the Lignite Vision 21 Project and the Resource Coalition project. From a resource reliability standpoint, the Applicants' analysis assumes that the reliability of these two units would be comparable to Big Stone Unit II.

As alluded to, however, the transmission upgrades necessary for the alternative coal resources have not been as well developed as the proposed interconnection facilities for Big Stone Unit II. As a result, it is not possible to make any direct comparison of the reliability between the transmission interconnection facilities for the resource alternatives to Big Stone Unit II. However, for purposes of this analysis, because federal interconnection procedures apply in the event of any proposed unit, the Applicants assume that the transmission interconnection facilities would be studied and designed to the same general level of rigor of reliability as is the case for the interconnection facilities for the proposed Big Stone Unit II. However, it is not assumed that any transmission interconnection facilities proposed in connection with other coal units would attempt to add incremental transmission capacity to better serve wind resources in western Minnesota or eastern South Dakota, as is the case with the facilities proposed in this proceeding.

Alternate Market Futures

The alternative resource options of Heartland, CMMPA, SMMPA, GRE and OTP all utilize market purchases to replace a portion or all of the applicable need that the Applicants intend the Big Stone Unit II to serve.

For OTP, a market purchase from MHEB is considered the next best resource option to participation in Big Stone Unit II. OTP's preferred resource scenario, which includes the Big Stone Unit II project, is more reliable than its next best case. The MHEB purchase includes receiving energy from hydro facilities located in the far north of Manitoba, being delivered to the OTP service territory over more than 1,000 miles of transmission lines. While hydroelectric facilities are typically more reliable than thermal facilities, the long distance over which the power is required to be transmitted makes this a less reliable alternative overall than the Big Stone Unit II project.

The largest single contingency in the MAPP region is the 500 kV line from Manitoba to the Twin Cities. When this line relays out and interrupts deliveries from MHEB, all other MAPP utilities must provide operating reserves to cover the lost supply. Even though smaller voltage lines remain in service, the export capability from Manitoba is severely reduced and all transactions are impacted. For OTP purchases from MHEB, the loss of the 500 kV line is a double hit. Not only does OTP lose a major resource, it must supply operating reserves. Manitoba Hydro has noted 12 outages of the 500 kV line from April 15, 2000 to February 22, 2006.

In contrast, the Big Stone Unit II power plant and transmission Projects will improve reliability in the region, whereas the purchase from MHEB will not since there are currently no plans to add any new transmission to increase the transfer capability out of Manitoba. Big Stone Unit II and the proposed associated transmission interconnection Projects will improve regional reliability through improved voltage support within the local area, and will positively impact the transient stability performance of the region. These improvements will support the ability of Minnesota to receive additional power through the North Dakota transmission system interface, which extends across Minnesota and South Dakota. The Big Stone Unit II associated transmission Projects have been developed with regional needs in mind. This includes coordination with other anticipated transmission projects being considered in Minnesota. These projects will improve the transmission capacity between a region that is integral to further regional wind energy development and the Twin Cities. At the current time, further wind development is currently constrained by the lack of transmission infrastructure.

Finally, purchases from MHEB have historically contained provisions that require the return of energy to MHEB from OTP during years when the Manitoba Province hydro resources experience water shortages. MHEB currently estimates a probability of slightly less than 10% annually of such shortages taking place. This requirement places an additional energy burden on OTP, its other resources, and the region as a whole when such shortages occur.

Alternative Gas Unit Futures

GRE, SMMPA, and MRES included additional gas-based capacity in their alternative resource options. Gas-based resources in the Midwest United States do not typically operate at the high capacity factors of baseload resources, such as the majority of coal and nuclear units. Because the combustion turbine units typically provide intermediate or peaking power supply and are thus off-line for a considerable amount of time, maintenance can often be performed when they are in an off-line status; thereby minimizing impacts to the availability of the unit.

Maintenance outages for coal units tend to be longer than for gas-based units. Because coal units typically have high dispatch rates (are operated as much as possible), any outage time counts against their availability. As a result, gas units tend to have higher availability than that considered for coal units.

Siting considerations for gas-based units typically allow the units to be closer to the load center than large central station plants. For the above three Applicants, this could provide a slight reliability advantage over Big Stone Unit II, since the delivery path may be shorter for the gas units than for Big Stone Unit II. However, any local transmission projects necessary to connect the gas units are not anticipated to enhance the regional transfer capability into Minnesota such as the improvement that Big Stone Unit II and its associated transmission Projects will provide.

If the gas options were pursued, transmission interconnection studies would be required for each of the units planned. For the above three Applicants, this would require transmission projects to connect each of the planned resources to the grid. It is expected that the transmission projects required for these three resources would not be the same as those considered for Big Stone Unit II. It is assumed that the transmission projects would be more local to the plant and load center and, due to the relatively small size of the units considered, would likely provide less regional transfer capability. Undoubtedly, the benefit would be less likely to provide benefit for the constrained transmission system between the Dakotas and Minnesota, and furthermore, in southwest Minnesota, an area of high priority for the state in terms of future winds energy development.

PART D

To the extent possible, further compare the resulting overall generation and demand-side alternative with the Big Stone projects, considering the elements listed in Minnesota Rules Part 7849.0340(B) (Item B).

The Order required information be provided with regard to Minnesota Rules Part 7849.0340(B) (Item B). Typically, information provided under Item B is available when a project has been developed to a significant level, including a detailed site selection study. The Applicants have provided Item B information in significant detail for the Big Stone Unit II project. However, none of the alternate plans has been developed to the level of completeness that the Big Stone Unit II has achieved. Those Applicants who are looking at gas-fired plants do not have specific sites identified nor have they started the siting and permitting process and little information is available for their alternate plans.

The Amount of Land Required

Big Stone Unit II

Big Stone Unit II would be located on an industrial site adjacent to the existing Big Stone Unit I. The members of Big Stone Unit I own the existing approximately 2,200-acre site. OTP owns a 295-acre parcel adjacent to the existing site and has under option to purchase, on behalf of the Big Stone Unit II owners, an additional 620 acres. The land required to construct Big Stone Unit II is 915 acres.

Alternative Projects

The alternative projects would include property for the:

- Lignite Vision 21 project- 283 acres.
- Resource Coalition project -The size for this project has not been determined since no site has been chosen at this time. The space required can be expected to be more than the Big Stone Unit II because it would be on a new site, rather than adding a second unit to an existing site.
- The property associated with the gas turbines needed for replacement capacity has not been determined due to these options being only considered as an alternate to the Big Stone Unit II project without specific siting studies having been performed. For a typical 50 MW gas turbine approximately 10 – 15 acres would be required. For a typical 50 MW combined cycle approximately 15 – 25 acres would be required.

The property required for transmission improvements associated with the above projects cannot be determined since the transmission studies to determine the necessary improvements also have not been performed.

The property associated with any generation and transmission resources constructed to satisfy market purchases is impossible to approximate.

(1) Induced Traffic

Big Stone Unit II

During the construction phase of the Big Stone Unit I, which came online in 1975, the immediate road infrastructure to and from the facility consisted of a series of gravel roads. Since the construction of Big Stone Unit I, all the local and immediate ingress and egress corridors have been upgraded to hard-surface roadways.

Traffic counts were conducted in 2003 at two locations in Grant County near Big Stone Unit I, specifically on U.S Highway 12 and County Road 109. The average daily traffic counts were 287 vehicles per day at the U.S. Highway 12 location and just 40 vehicles per day at the County Road 109 location.

The Applicants are fully aware of the increased utilization of local roadways by construction workers' private vehicles to get to and from the Big Stone Unit II construction site and will be providing off-road private parking in designated onsite parking areas.

Anticipated truck traffic to the Big Stone Unit II construction site will vary during the various phases of construction. Additional truck traffic during construction would consist of periods of increased traffic over relatively short time periods (days and weeks) rather than the approximately 50 trucks per 24-hour day, seven days per week experienced at the Northern Lights Ethanol plant. Construction timetable deliveries and drop-offs by contractors and vendors will ultimately flow with the progress of the construction project.

At the peak of the construction project (approximately May through June 2009), it is estimated that the worker force will reach 1,400 maximum personnel. One of the project initiatives to mitigate any possible parking impacts is to designate off-road onsite parking facilities to accommodate workers' private vehicles. It is also highly unlikely that 1,400 workers' vehicles would arrive simultaneously at any given time. Work shift schedules will help diffuse traffic and parking problems. It is also likely that the labor force will practice some form of car-pooling, thus further mitigating any traffic or parking impacts.

Law enforcement will be more visible during the construction phase of the Project and will increase patrol activities. Traffic counters could be temporarily installed on corridors that may present some transportation issues and provide law enforcement and other transportation specialists opportunities for proactive solutions to mitigate potential impacts.

Portable radar signs to inform drivers of their speed or the presence of a South Dakota Motor Carrier Enforcement official are among the possible actions that could be taken to mitigate potential traffic problems.

In the unlikely event that worker traffic and parking becomes an issue, an independent private transportation vendor could provide transportation to and from the construction site.

Potential transportation issues or problems do not appear to be significant issues with law enforcement, the Grant County Highway Superintendent, or the Northern Lights Ethanol plant Traffic Facilitator. The transportation corridors are sound and have been significantly improved since the construction of Big Stone Plant unit I in 1975. County corridors have recently been improved, are being improved, and are scheduled for long-term maintenance and improvements.

OTP currently utilizes railroads and the corridor of roads and highways to augment the operation of Big Stone Unit I. Currently, the Burlington Northern Santa Fe (BNSF) railroad provides three to four coal train deliveries per week to the Big Stone Unit I. Each of these coal train deliveries consist of approximately 115 coal cars. Increasing the number of coal cars per train to accommodate the operation of Big Stone Units I and II does not appear to be feasible. Therefore, the number of individual coal train deliveries per week will increase when Big Stone Unit II comes on line in 2011.

The Applicants estimate that there will be an increase from the current coal train deliveries (115 coal cars each) of three to four per week to six to eight deliveries per week to accommodate the additional fuel demands of Big Stone Unit II. The number of trains that pass through Milbank, South Dakota will increase from the current three to four per week to six to eight per week. The overpass and underpass system in Milbank mitigates any train transportation impacts.

Alternative Scenarios

The Applicants' alternative projects would require road and other transportation infrastructure be constructed to support two coal plants, one combined cycle and two simple cycle power plants. The coal projects would have similar impacts to the traffic in the area where they were constructed as described for the Big Stone Unit II. The construction equipment and workforce requirements would be similar as to the Big Stone Unit II for each of the coal plants.

The gas-fired plants would have less of an impact on traffic.

The Lignite Vision 21 project is a mine-mouth plant, and no additional rail or truck traffic would be required for fuel hauling. No specific site has been chosen for the Resource Coalition unit yet, however, it is expected that its rail haul expenses would be less than for Big Stone Unit II because the likely sites would have less rail miles of coal delivery from the Powder River Basin coal fields.

(2) Fuel Requirements

Big Stone Unit II

The maximum expected annual fuel use for the Big Stone Unit II facility is 2.0 – 3.3 million tons per year.

Alternative Scenarios

The Lignite Vision 21 project is estimated to require 1.3 million tons of lignite fuel per year. The Resource Coalition project is expected to require approximately 392,000 tons per year of coal just for the output required by MRES. GRE's alternate coal resource in 2014 would use approximately the same amount of coal as their percentage share of Big Stone Unit II. This would be approximately 250,000 tons of coal per year.

The energy expected to be produced by the gas units in the alternative resource scenarios will require an estimated 7,214,000 MCF of natural gas per year.

(3) Airborne Emissions

The estimated emissions from the scenarios with Big Stone Unit II and the alternate scenarios without Big Stone Unit II are summarized in Table 10 which is repeated here as Table 13.

Table 13
Incremental Externality Emissions Summary
(Tons)

CO_2 EMISSIONS INSIDE MN ONLY

Annual Total Emissions		2011	2012	2013	2014	2015	2016	2017	2018
NOx	BSPII Option	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.0
	Alternate	1,389.20	1,574.54	1,533.98	1,510.18	1,610.88	1,538.25	1,492.41	1,440.7
CO_2	BSPII Option	25,014.93	0.00	0.00	0.00	0.00	0.00	0.00	0.0
	Alternate	1,100,865.02	1,235,387.03	1,220,291.69	1,333,844.93	1,342,325.05	1,326,524.00	1,333,749.72	1,315,456.3
Pb	BSPII Option	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.1
	Alternate	0.12	0.12	0.12	0.11	0.12	0.22	0.12	0.2
CO	BSPII Option	2,187.78	2,172.03	2,172.66	2,172.03	2,172.03	2,172.03	2,172.03	2,172.0
	Alternate	1,953.95	2,126.44	2,092.08	2,683.90	2,806.98	2,787.76	2,802.98	2,814.3
PM_{10}	BSPII Option	655.27	651.61	651.61	651.61	651.61	651.61	651.61	651.6
	Alternate	973.76	1,074.00	1,106.44	1,236.40	1,328.42	1,354.65	1,387.58	1,400.5
Hg	BSPII Option	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.0
	Alternate	0.20	0.20	0.20	0.21	0.21	0.21	0.21	0.2
SO_2	BSPII Option	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.0
	Alternate	13,273.48	14,630.36	14,476.33	14,316.32	13,129.27	14,260.19	14,412.81	14,461.7

CO_2 EMISSIONS INSIDE & OUTSIDE OF MN

Annual Total Emissions		2011	2012	2013	2014	2015	2016	2017	2018
NOx	BSPII Option	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.0
	Alternate	1,389.20	1,574.54	1,533.98	1,510.18	1,610.88	1,538.25	1,492.41	1,440.7
CO_2	BSPII Option	4,482,023.55	4,457,008.61	4,457,008.61	4,474,014.19	4,457,008.61	4,457,008.61	4,473,668.73	4,480,667.0
	Alternate	3,175,693.50	3,624,434.92	3,552,201.88	3,913,217.38	4,052,892.26	4,006,337.82	4,072,925.69	4,071,684.5
Pb	BSPII Option	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.1
	Alternate	0.12	0.12	0.12	0.11	0.12	0.22	0.12	0.2
CO	BSPII Option	2,187.78	2,172.03	2,172.66	2,172.03	2,172.03	2,172.03	2,172.03	2,172.0
	Alternate	1,953.95	2,126.44	2,092.08	2,683.90	2,806.98	2,787.76	2,802.98	2,814.3
PM_{10}	BSPII Option	655.27	651.61	651.61	651.61	651.61	651.61	651.61	651.6
	Alternate	973.76	1,074.00	1,106.44	1,236.40	1,328.42	1,354.65	1,387.58	1,400.5
Hg	BSPII Option	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.0
	Alternate	0.20	0.20	0.20	0.21	0.21	0.21	0.21	0.2
SO_2	BSPII Option	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.0
	Alternate	13,273.48	14,630.36	14,476.33	14,316.32	13,129.27	14,260.19	14,412.81	14,461.7

(4) Water Appropriation and Consumption

Big Stone Unit II

Table 14
Annual Water Appropriation & Consumption

Water Use	
Maximum Groundwater withdrawal rate	0 gpm
Annual Groundwater Appropriation	0 acre-feet
Maximum Surface Water Withdrawal Rate	100 cfs
Annual Surface Appropriation	10,900 acre-feet

Source: Table 2-6 of the Application for Energy Facility Siting Permit, July 2005.

Alternative Scenarios
For the Lignite Vision 21, 224 acre-feet per year is expected to be required. For the Resource Coalition, water usage similar to Big Stone Unit II is expected to be required.

Although the market purchases would be generated from units expected to consume water, no estimation has been developed for these transactions.

(5) Discharges to Water

Big Stone Unit II
Big Stone Unit II will be a zero liquid discharge (ZLD) facility, which utilizes wastewater concentration equipment designed so that no wastewater will leave the facility. (Source: Section 2.2.8 of the Application for Energy Facility Siting Permit, July 2005)

Alternative Scenarios
Lignite Vision 21 and the Resource Coalition plants are expected to be zero discharge facilities.

(6) Reject Heat

Big Stone Unit II
Big Stone Unit II includes a wet cooling system, which uses circulating water to condense turbine-generator exhaust steam in a shell and tube heat exchanger (condenser).

The wet cooling system functions by circulating cool water to the tube side of the condenser where heat is transferred from the shell-side steam. Steam exhausted from the steam-turbine-generator flows into the condenser and is condensed through indirect heat transfer with the cool circulating water. The condensed steam (condensate) is collected in the condenser where condensate pumps return it to the boiler feedwater system.

The warm water is then circulated from the condenser through a wet, multiple cell, mechanical draft cooling tower. The wet mechanical draft cooling tower dissipates heat through evaporation by contacting the warm circulating water with ambient air. Once cooled, the circulating water is returned to the condenser to complete the cooling circuit.

Due to circulating water evaporation, a water vapor plume will be emitted into the atmosphere from the cooling tower. Small droplets of circulating water (drift) will be entrained within the cooling tower plume. The drift will contain both dissolved and suspended solids, which essentially will be converted to particulate matter in the atmosphere, as water within the drift droplets evaporates. As a result, the cooling tower will be a source of particulate emissions. Specially designed drift eliminators will be employed to remove droplets from the cooling tower plume, which will both conserve water, and reduce drift and resultant particulate emissions.

Most of the makeup water entering the Big Stone Unit II circulating water circuit will be consumed by cooling tower evaporation and drift. The remaining makeup water will replace circulating water blowdown, which is required to maintain circulating water chemistry (cycles of concentration). In order to conserve fresh water from the Big Stone Lake, Big Stone Unit I cooling pond water will be reused as makeup to Big Stone Unit II cooling tower.

The Big Stone Unit II circulating water system will operate at approximately 3.7 cycles of concentration. Again, in order to conserve fresh water, a portion of the Big Stone Unit II cooling tower blowdown will be reused as makeup water to the wet flue gas desulfurization system ("FGD System" or "Scrubber"). Blowdown from the circulating water system will be discharged to a new cooling tower blowdown holding pond, which will serve as the makeup water source for the scrubber. Excess water not used by the scrubber, along with blowdown from the scrubber, will be sent to a "Zero Liquid Discharge System" or ZLDS. This system includes brine concentrators and other equipment, necessary to achieve "zero water discharge" from the Big Stone site. Blowdown (wastewater) from the Big Stone Unit I and Big Stone Unit II is evaporated, leaving the previously dissolved solids of the blowdown water in a solid form for disposal. The evaporated water is condensed and reused within the Big Stone Plant or sent to the ethanol plant.

(Source: Section 2.2.2 of the Application for Energy Facility Siting Permit, July 2005)

Alternative Scenarios

The heat rejection systems of the coal and combined cycle alternatives would operate on similar principles to the Big Stone Unit II heat rejection system. Since the alternative projects are not to the level of design as the Big Stone Unit II, details of their systems cannot be provided.

(7) Radioactive Releases

Big Stone Unit II

Big Stone Unit II may use radioactive sources to monitor coal levels or coal flow and wet scrubber slurry density. Those sources will likely contain Cesium 137 and are regulated by the U.S. Nuclear Regulatory Commission. (Source: Section 4.8 of the Application for Energy Facility Siting Permit, July 2005)

Alternative Scenarios

There is no significant source of radioactive elements in the alternative generating units considered in the alternate futures. The LV21 and Resource Coalition coal units may use radioactive sources similar to those considered for Big Stone Unit II. As the detailed designs for these units have been started, it is not certain what type of flow and monitoring systems will be employed.

There may be market purchases that are sourced from existing nuclear units in the region. Although direct contracting with these units is not anticipated, they may have excess energy to provide to the market from time to time which could be acquired by the Applicants as spot market purchases.

(8) Solid Waste Production

Big Stone Unit II

Coal combustion by-products will consist primarily of bottom ash, fly ash, and gypsum from the wet FGD system. Big Stone Unit I has a current permit to operate a Solid Waste Facility. The Big Stone Plant Unit I Co-owners plan to request a permit amendment or other applicable permit revision to allow Big Stone Unit II solid waste disposal in the existing Big Stone Unit I solid waste facility.

The existing landfill will accommodate approximately 10 years of disposal before it will need to be expanded. This projection is based on average coal characteristics, an 88 percent plant capacity factor, and expected average ash content of the coal. The Project does not include any disposal reduction for sales or other possible utilization of Big Stone Unit II coal combustion by-products. Prior to the end of the useful life of the existing facility, a new solid waste facility will be jointly developed for Big Stone Unit I and Big Stone Unit II. (Source: Section 4.8 of the Application for Energy Facility Siting Permit, July 2005)

Table 15
Estimated Annual Coal Combustion By-Product Generation

By-Product	Big Stone Unit II Average	Big Stone Unit I Average	Big Stone Unit II Maximum	Big Stone Unit I Maximum
Bottom Ash	32,000	84,000	73,000	230,000
Fly Ash	127,000	45,000	293,000	124,000
Gypsum	62,000	51,000	183,000	177,000
Total	221,000	180,000	549,000	531,000

Source, Table 2-2 from the Application for Energy Facility Siting Permit, July 2005)

Alternative Scenarios

The Lignite Vision 21 Project is estimated to generate the following solid waste products:

Table 16
Lignite Vision 21 Project Solid Waste Products

Waste Product	Tons per year
Fly Ash	211,000
Bottom Ash	90,000
Sludge	N/A

Since the LV21 project is a circulating fluidized bed unit, the ash and sludge from this facility is not suitable for sales as byproducts and will have to be landfilled. It is anticipated that this waste will be used as fill where lignite has been mined. It is expected that the Resource Coalition project will generate solid waste similar to the Big Stone Unit II amount above.

(9) Audible Noise

Big Stone Unit II

No noise standards have been promulgated in South Dakota. The Minnesota Pollution Control Agency has established standards for environmental noise in Minnesota. While the Minnesota standards do not apply in South Dakota where the Big Stone Unit II is located, the Minnesota standards do provide one benchmark for evaluation on measured noise levels near the residences.

The Minnesota standards apply at the nearest receptor and specific to the type of land use at the receptor location. To establish the audible noise impacts of the Big Stone Unit II unit, Barr Engineering monitored sound levels at four locations at and around the perimeter of the Big Stone Power Plant for use in modeling for the Big Stone Unit II unit. New sources were also simulated in modeling software to calculate the potential noise levels. The software modeling considers noise levels under ideal conditions for noise propagation, yielding appropriately conservative results.

Modeled noise levels expected from Big Stone Unit II will have no significant impact on the noise levels in surrounding areas. The maximum predicted increase is 4 dB. A 3 dB increase is just barely noticeable. Increases from Big Stone Unit II are not predicted to cause any new exceedences of the reference Minnesota noise standards.

(Source: Section 4.5.4 of the Application for Energy Facility Siting Permit, July 2005)

Alternative Scenarios

The Lignite Vision 21 project would produce 90 dbA at three feet horizontal and five feet vertical. The far field noise level has not been determined. Noise emissions from the Resource Coalition and gas fired project would be within the parameters established for the construction and operating permit.

(10) Labor Requirements

Big Stone Unit II

During the construction phase of Big Stone Unit II, the labor force is expected to peak at approximately 1,400 workers onsite. The duration of the peak 1,400 onsite workers could possibly be up to, but probably not exceeding, one year. This projected peak of 1,400 construction personnel is anticipated to occur on about the middle of the third year of construction. This anticipated labor peak of 1,400 workers for the anticipated one-year duration would equate to approximately 3.1 million construction labor-hours and represent about 60 percent of the Project's total labor-hour estimate of 5.1 million labor-hours.

The average number of onsite workers for the duration of the Project (2007-2011) is estimated to be approximately 625. During any phases of the construction project, there is expected to be a heterogeneous profile of the workforce. This profile would include: unskilled labor, skilled labor, technical, and advanced technical. The unskilled labor for the Project will constitute approximately 5 percent of the estimated labor requirement. The projected range for unskilled labor during the various stages of the construction project is from 3.5 to 70 positions.

The proposed construction project would offer opportunities for local contractors and vendors, and new service jobs will be created to support the influx of workers. The local job growth is estimated at 2,550 full time equivalent positions during the construction phase of Big Stone Unit II for the local four counties (1,997 full- and part-time jobs in the communities for an average of 1,378 per year for four years).

In 2008 dollars, the estimated value added by all labor (2,550 jobs) on the Project over a four-year period is $211 million. It is estimated that the labor income for businesses in the four-county area selling goods and services to the Project is $93 million, which will employ 2,059 people either full- or part-time. Assuming 50 percent of estimated induced expenditures are local, $51.9 million and 1,263 full- and part-time jobs is the estimated value added by people providing goods and services to the households of the workers on the construction site and in the local businesses identified as indirectly supporting the construction effort.

The wage scales at this juncture are not determined but typically, the nature of construction work is such that the wage scales are competitive. The Big Stone Unit II construction phase should have a wide range of applicants from which to choose. It is expected that the local labor pool would supply a portion of the semi-skilled and skilled project labor personnel.

Long-term local labor benefits are projected to be 35 full-time equivalents employed in the operations. Twenty-nine full-time and part-time positions are projected to be created in the communities. The operation of the Big Stone Unit II will begin in 2011. OTP estimates that Big Stone Unit II will require an additional 35 employees at a cost in payroll including benefits of approximately $2.5 million at 2004 wage levels. The 35 new power plant jobs are estimated to create another 28.8 jobs locally. The associated $2.5 million payroll for the additional Big Stone Unit II employees is expected to result in a total economic activity increase of $3.1 million as these new households purchase goods and services in the area and the money makes its way through the economy.

Although many of the full-time employees of Big Stone Unit II will be new residents to the area, much of the plant's operation and maintenance labor force will be hired locally. Five facets of the local and county population will be available to meet the plant's employment needs—those who are currently unemployed, those who are currently underemployed, farmers who are in need of additional seasonal income, and those who are currently not in the workforce but, by the nature of the timeline of the construction, may opt to rejoin the workforce or become chronologically eligible to join the workforce.

Other labor contingencies not included in the survey data are those labor personnel available from areas and communities that are not included in the 20-mile Project radius study, four county area. Some of these larger communities would include: Sisseton, South Dakota, Watertown, South Dakota, Webster, South Dakota, Madison, Minnesota, and Benson, Minnesota.

(Source: Section 5.1 of the Application for Energy Facility Siting Permit, July 2005)

Alternative Scenarios

The Lignite Vision 21 project is expected to employ 56 full-time on site employees. It is anticipated that the Resource Coalition project would employ approximately 100 full time staff since this will be the first unit at the site. The gas fired projects are not anticipated to create more than about 10 full time positions at the plants.

PART E

To the extent possible, discuss how changes in demand or changes in the in-service dates of the indicated resources would affect the above comparisons.

The delay of the in-service date of Big Stone Unit II will require the Applicants to acquire capacity and energy to bridge the period between the original date and the revised date. The Applicants have a variety of approaches to meeting this potentiality. The approaches rely on acquisition of the capacity from peaking capacity or market purchases. The energy would be acquired from operation of less efficient resources as well as market purchases. The Applicants have identified the following additional power supply costs for one and two years of delay of the in-service date of the Big Stone Unit II.

OTP - Delays or schedule changes that result in a later commercial operational date for the Big Stone Unit II project would cost OTP and its customers more money. OTP currently has need for the Big Stone Unit II capacity and energy up to one year before the commercial operation date. The following table identifies the approximate costs to OTP for delay for Big Stone Unit II.

Table 17
Costs to OTP for Big Stone Unit II Delay

Implementation of Big Stone Unit II	Otter Tail Power Company Estimated Cost of Delay NPV over the period 2003 – 2034 2005$
On-time	Base
1 year delay	Base + $19,517,000
2 year delay	Base + $32,626,000

In developing its resource plan, OTP developed contingency resource plans under low growth and high growth scenarios. Obviously, the high growth scenario would support even a larger share of the Big Stone Unit II project. Even under the low growth scenario, the resource planning model selected almost all of Big Stone Unit II available to OTP, so changes in demand do not have a material impact on the comparisons between the two plans.

CMMPA - CMMPA has evaluated options for meeting the baseload needs of its members and believes that the economics of adding baseload resources favors coal. Changes in demand or in-service dates would not change need for baseload coal resources like Big Stone Unit II for CMMPA members since their only other coal resource is a 13 MW unit power purchase from Nebraska City #2 scheduled for service in 2009. The table below shows the projected net present value cost impacts to CMMPA from delaying the Big Stone Unit II project by one to three years expressed in 2005 dollars.

Table 18
NPV Costs to CMMPA for Big Stone Unit II Delay

Implementation of Big Stone Unit II	System Production Costs – 15 year NPV
1 year delay	$272,000 Increase
2 year delay	$608,000 Increase
3 year delay	$1,076,000 Increase

GRE - GRE's portion of Big Stone Unit II project represents a small percentage of its projected future needs (about 3 years of forecasted energy growth and a little over one year of forecasted demand growth). Therefore, changes in demand or in-service dates will have only a minimal impact on the above comparisons, most likely only shifting GRE's needs ahead or back by a short period of time. For example, if GRE's energy requirements grow less quickly than expected, GRE's need for baseload capacity and energy might be delayed for a year or two. Conversely, if GRE's demand grows more quickly or if Big Stone Unit II is delayed, GRE will need to find baseload capacity and energy from the market to cover its needs until such time as Big Stone Unit II is available.

Heartland - As shown in the table below, delay of implementation of Big Stone Unit II would result in additional cost to the Heartland system and its customers:

Table 19
Costs to Heartland System for Big Stone Unit II Delay

Implementation of Big Stone Unit II	System Production Costs – 15 year NPV
On-time	Base
1 year delay	Base + $3,393,000
2 year delay	Base + $7,144,000

The above costs are a result of additional market purchases, which are projected to be higher cost than the energy acquired from the Big Stone Unit II source.

Montana-Dakota - Changes in demand would not affect the above comparisons for Montana-Dakota. It has been determined that, under the various load forecast scenarios, baseload coal-fired generation will be the "best-cost" resource option for the company to meet its customer demand for electricity in the future.

On the other hand, delaying Big Stone Unit II would subject Montana-Dakota to having to use rental combustion turbines to meet its capacity requirements and purchase the needed energy from the market to meet its energy requirements. Assuming the needed energy would be available at prices that are comparable to the market prices during April 2005 – January 2006, Montana-Dakota's production costing model PROSYM shows that the company and its customers would have to incur the following incremental costs if the in-service date of Big Stone Unit II is delayed from June 1, 2011 to June 1, 2014:

Table 20
Incremental Costs to Montana-Dakota for Big Stone Unit II Delay

Year	Incremental Cost (million dollars)
2011	15.000
2012	30.495
2013	30.007
2014	14.471

MRES - Delaying Big Stone Unit II would subject MRES to purchasing from the market and to using its peaking resources to meet the energy and capacity requirements of its members. Below are shown the expected net-present-value cost impacts to MRES, in 2005 dollars, from delaying the Big Stone Unit II project by one to two years. These costs assume there is sufficient warning of the Big Stone Unit II delay to allow construction of a peaking resource by 2011 to make up for the capacity shortfall. Otherwise, the cost impact would be larger yet.

Table 21
Expected NPV Costs to MRES for Big Stone Unit II Delay

Implementation of Big Stone Unit II	MRES Production Cost Impacts – 15 year NPV (2005 dollars)
1 year delay	$7,174,000 Increase
2 year delay	$8,037,777 Increase

SMMPA - Delaying Big Stone Unit II would subject SMMPA to having to purchase from the market and use its peaking resources to meet the energy and capacity requirements of its members. Depending upon the length of the delay, the only realistic options open to SMMPA may be to pursue the other resource alternatives outlined previously. While SMMPA's next best alternative to participation in Big Stone Unit II is another approximately 50 MW participation in another pulverized coal plant, or the construction of its own small scale coal facility, the timing makes an alternative coal-based facility by 2011 increasingly unlikely. The result of not having the Big Stone Unit II available in 2011 will be to limit alternative choices to gas combustion turbine and combined cycle options with the increased costs of operation on natural gas or procure the capacity and energy during the time delay from the market.

Below are the expected annual cost impacts to SMMPA from delaying the Big Stone Unit II project by one, two years or three years. Costs were determined by delaying the start of BIG Stone Unit II by one two or three years in the capacity expansion model (EGEAS).

Table 22
Expected Annual Costs to SMMPA for Big Stone Unit II Delay

Implementation of Big Stone Unit II	SMMPA'S Production Costs Impacts- ANNUAL (Millions of Dollars)
1 Year Delay	$16.215
2 Year Delay	$32.790
3 Year Delay	$50.227

PART F

Provide any other information deemed relevant to comparing the Applicants' proposal and the alternative described above.

Economic Impacts: Failure to receive approval and construction of the Big Stone Unit II project would result in the loss of significant economic benefit and development to the northeastern area of SD, the southwestern area of MN, and both states in general. In the case of OTP's resource plan, the Alternate Resource Plan would transfer OTP's share of the economic development and economic benefit and the associated jobs to Manitoba.

Enhanced Transmission for Wind: The construction of the transmission Projects associated with Big Stone Unit II will provide increased transfer capability for wind development in the southwest part of Minnesota and the Twin Cities.

Reduction in SO_2 from Big Stone: The construction of Big Stone Unit II will provide a common scrubber and bag house that will assist in reducing SO_2 emissions for Big Stone Unit I.

Appendix A
Emissions Estimates by Emission Type and by Applicant

BSPII and Alternate Incremental Emission Summary by Emission Type

BSPII OPTION	2011	2012	2013	2014	2015	2016	2017	2018	
Annual SO_2 Emissions									
CMMPA [1]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
HEARTLAND [1]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
MDU [1]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
GRE [1]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
MRES [2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
OTP [2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
SMMPA [2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
BSPII [3]	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,0
BSPI Adjustment [4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total Annual SO_2 Emissions (tons)	**1,086.02**	**1,086.02**	**1,086.02**	**1,086.02**	**1,086.02**	**1,086.02**	**1,086.02**	**1,086.02**	**1,0**
Annual NOx Emissions									
CMMPA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
HEARTLAND	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
MDU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
GRE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
MRES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
OTP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
SMMPA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
BSPII	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,0
Total Annual NOx Emissions (tons)	**1,086.02**	**1,086.02**	**1,086.02**	**1,086.02**	**1,086.02**	**1,086.02**	**1,086.02**	**1,086.02**	**1,0**
Annual CO_2 Emissions									
Inside Minnesota									
CMMPA	0	0	0	0	0	0	0	0	
HEARTLAND	0	0	0	0	0	0	0	0	
GRE	0	0	0	0	0	0	0	0	
OTP - inside MN	25,015	0	0	0	0	0	0	0	
Subtotal Annual CO_2 Emissions (tons)	25,015	0	0	0	0	0	0	0	
Outside Minnesota									
MDU	0	0	0	0	0	0	0	0	
MRES	0	0	0	0	0	0	0	0	
OTP - outside MN	0	0	0	0	0	0	0	0	
SMMPA	0	0	0	17,006	0	0	16,660	3,658	1
BSPII	4,457,009	4,457,009	4,457,009	4,457,009	4,457,009	4,457,009	4,457,009	4,457,009	4,45
Subtotal Annual CO_2 Emissions (tons)	4,457,009	4,457,009	4,457,009	4,474,014	4,457,009	4,457,009	4,473,669	4,460,667	4,47
Total Annual CO_2 Emissions (tons)	**4,482,024**	**4,457,009**	**4,457,009**	**4,474,014**	**4,457,009**	**4,457,009**	**4,473,669**	**4,460,667**	**4,47**
Annual Pb Emissions									
CMMPA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
HEARTLAND	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
MDU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
GRE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
MRES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
OTP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
SMMPA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
BSPII	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	
Total Annual Pb Emissions (tons)	**0.17**	**0.17**	**0.17**	**0.17**	**0.17**	**0.17**	**0.17**	**0.17**	

BSPII and Alternate Incremental Emission Summary by Emission Type

BSPII OPTION	2011	2012	2013	2014	2015	2016	2017	2018	
Annual CO Emissions									
CMMPA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
HEARTLAND	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
MDU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
GRE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
MRES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
OTP	15.75	0.00	0.63	0.00	0.00	0.00	0.00	0.00	
SMMPA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
BSPII	2,172.03	2,172.03	2,172.03	2,172.03	2,172.03	2,172.03	2,172.03	2,172.03	2,1
Total Annual CO Emissions (tons)	**2,187.78**	**2,172.03**	**2,172.66**	**2,172.03**	**2,172.03**	**2,172.03**	**2,172.03**	**2,172.03**	**2,1**
Annual PM_{10} Emissions									
CMMPA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
HEARTLAND	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
MDU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
GRE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
MRES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
OTP	3.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
SMMPA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
BSPII	651.61	651.61	651.61	651.61	651.61	651.61	651.61	651.61	6
Total Annual PM_{10} Emissions (tons)	**655.27**	**651.61**	**651.61**	**651.61**	**651.61**	**651.61**	**651.61**	**651.61**	**6**
Annual Hg Emissions									
CMMPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
HEARTLAND	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
MDU	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
GRE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
MRES	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
OTP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
SMMPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
BSPII	0.054	0.054	0.054	0.054	0.054	0.054	0.054	0.054	
Total Annual Hg Emissions (tons)	**0.054**	**0.054**	**0.054**	**0.054**	**0.054**	**0.054**	**0.054**	**0.054**	

2118

BSPII and Alternate Incremental Emission Summary by Emission Type

	2011	2012	2013	2014	2015	2016	2017	2018	
BEST INDIVIDUAL ALTERNATIVE OPTION [6]									
Annual SO_2 Emissions									
CMMPA	358.34	614.30	614.30	614.30	614.30	614.30	614.30	614.30	6
HEARTLAND	529.98	529.98	529.98	529.98	529.98	529.98	529.98	529.98	5
MDU	310.05	310.05	310.05	310.05	310.05	310.05	310.05	310.05	3
GRE	0.00	0.00	0.00	209.96	209.96	209.96	209.96	209.96	2
MRES	583.58	1,406.04	1,285.77	924.11	777.16	804.59	961.89	1,081.36	1,0
OTP	6,298.00	6,520.47	6,480.35	6,528.57	5,880.51	6,507.04	6,522.09	6,420.41	6,3
SMMPA	765.72	821.84	828.74	772.60	849.22	858.21	837.96	869.84	8
BSPI Adjustment	4,427.80	4,427.68	4,427.14	4,426.75	3,958.09	4,426.07	4,426.57	4,425.81	4,4
Total Annual SO_2 Emissions (tons)	**13,273.48**	**14,630.36**	**14,476.33**	**14,316.32**	**13,129.27**	**14,260.19**	**14,412.81**	**14,461.71**	**14,3**
Annual NOx Emissions									
CMMPA	26.06	44.68	44.68	44.68	44.68	44.68	44.68	44.68	
HEARTLAND	38.54	38.54	38.54	38.54	38.54	38.54	38.54	38.54	
MDU	733.88	733.88	733.88	733.88	733.88	733.88	733.88	733.88	7
GRE	185.73	185.73	185.73	209.96	209.96	209.96	209.96	209.96	2
MRES	87.20	147.21	135.62	259.16	304.82	286.87	317.97	306.35	3
OTP	19.96	119.82	104.89	109.08	115.30	88.15	85.94	18.33	
SMMPA	297.83	304.68	290.65	114.87	163.70	136.18	61.44	88.99	1
Total Annual NOx Emissions (tons)	**1,389.20**	**1,574.54**	**1,533.98**	**1,510.18**	**1,610.88**	**1,538.25**	**1,492.41**	**1,440.73**	**1,4**
Annual CO_2 Emissions									
Inside Minnesota									
CMMPA	119,815	205,398	205,398	205,398	205,398	205,398	205,398	205,398	2(
HEARTLAND	177,206	177,206	177,206	177,206	177,206	177,206	177,206	177,206	1
GRE	803,844	803,844	803,844	896,122	896,122	896,122	896,122	896,122	8
OTP - inside MN	0	48,940	33,844	55,119	63,599	47,798	55,024	36,730	
Subtotal Annual CO_2 Emissions (tons)	1,100,865	1,235,387	1,220,292	1,333,845	1,342,325	1,326,524	1,333,750	1,315,456	1,2
Outside Minnesota									
MDU	1,802,851	1,802,851	1,802,851	1,802,851	1,802,851	1,802,851	1,802,851	1,802,851	1,8
MRES	248,653	523,888	480,268	771,718	874,663	860,969	936,042	951,749	9
OTP - outside MN	5,081	10,521	6,244	4,603	5,525	14	283	1,629	
SMMPA	18,244	51,788	42,547	0	27,529	15,980	0	0	
Subtotal Annual CO_2 Emissions (tons)	2,074,828	2,389,048	2,331,910	2,579,372	2,710,567	2,679,814	2,739,176	2,756,228	2,7
Total Annual CO_2 Emissions (tons)	**3,175,693**	**3,624,435**	**3,552,202**	**3,913,217**	**4,052,892**	**4,006,338**	**4,072,926**	**4,071,685**	**4,0**
Annual Pb Emissions									
CMMPA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
HEARTLAND	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
MDU	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	
GRE	0.00	0.00	0.00	0.08	0.08	0.08	0.08	0.08	
MRES	0.00	0.00	0.00	0.02	0.03	0.03	0.03	0.03	
OTP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
SMMPA	0.10	0.10	0.10	0.00	0.00	0.10	0.00	0.10	
Total Annual Pb Emissions (tons)	**0.12**	**0.12**	**0.12**	**0.11**	**0.12**	**0.22**	**0.12**	**0.22**	

2119

BSPII and Alternate Incremental Emission Summary by Emission Type

	2011	2012	2013	2014	2015	2016	2017	2018
BEST INDIVIDUAL ALTERNATIVE OPTION								
Annual CO Emissions								
CMMPA	48.86	83.77	83.77	83.77	83.77	83.77	83.77	83.77
HEARTLAND	72.21	72.21	72.21	72.21	72.21	72.21	72.21	72.21
MDU	1,256.53	1,256.53	1,256.53	1,256.53	1,256.53	1,256.53	1,256.53	1,256.53
GRE	335.06	335.06	335.06	671.88	671.88	671.88	671.88	671.88
MRES	93.27	205.39	188.13	467.19	567.03	565.83	592.05	602.15
OTP	0.00	9.50	0.00	9.87	15.26	5.71	12.07	9.61
SMMPA	148.02	163.98	156.39	122.44	140.30	131.83	114.46	118.19
Total Annual CO Emissions (tons)	**1,953.95**	**2,126.44**	**2,092.08**	**2,683.90**	**2,806.98**	**2,787.76**	**2,802.98**	**2,814.34**
Annual PM_{10} Emissions								
CMMPA	21.50	36.86	36.86	36.86	36.86	36.86	36.86	36.86
HEARTLAND	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80
MDU	224.38	224.38	224.38	224.38	224.38	224.38	224.38	224.38
GRE	140.92	140.92	140.92	125.98	125.98	125.98	125.98	125.98
MRES	46.58	95.98	88.03	123.83	136.40	132.97	147.40	149.33
OTP	0.00	18.66	16.86	20.60	23.70	19.67	19.44	4.23
SMMPA	508.59	525.41	567.59	672.95	749.31	782.99	801.72	828.00
Total Annual PM_{10} Emissions (tons)	**973.76**	**1,074.00**	**1,106.44**	**1,236.40**	**1,328.42**	**1,354.65**	**1,387.58**	**1,400.57**
Annual Hg Emissions								
CMMPA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
HEARTLAND	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
MDU	0.196	0.196	0.196	0.196	0.196	0.196	0.196	0.196
GRE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
MRES	0.000	0.000	0.000	0.005	0.007	0.007	0.007	0.007
OTP	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001
SMMPA	0.006	0.007	0.006	0.004	0.005	0.004	0.003	0.003
Total Annual Hg Emissions (tons)	**0.202**	**0.203**	**0.203**	**0.206**	**0.209**	**0.208**	**0.207**	**0.207**

NOTES

[1] Emissions for CMMPA, Heartland, MDU, and GRE resources other than BSPII are not provided. The BSPII emissions are included in the BSPII line item for each pollutant.

[2] Emissions provided by MRES, OTP, and SMMPA are the incremental emissions from their respective resources other than BSPII. The BSPII emissions are included in the BSPII line item for each pc

[3] Emissions provided for BSPII are calculated based on a 600 MW plant with an 88 percent capacity factor. The rates at which emissions are generated are shown in Table 10.

[4] Includes BSPI emissions for percentage share ownership held by parties other than Otter Tail Power. BSPI emission for percentage share ownership held by Otter Tail Power is included in Otter Tail Power's emissions estimates.

[5] Total Annual CO2 emissions inside of Minnesota include the incremental emissions from SMMPA and OTP resources inside MN.

[6] Emissions provided by all of the applicants are the incremental emissions for the best individual alternative option.

[7] Total Annual CO2 emissions inside of Minnesota include the incremental emissions from CMMPA, Heartland, GRE, and SMMPA. Emissions for OTP resources inside MN are also included.

2120

BSPII and Alternate Incremental Emission Summary by Applicant

		2011	2012	2013	2014	2015	2016	2017	2018	2019
WITH BSPII OPTION										
CMMPA[1]										
SO2	tons/yr	0	0	0	0	0	0	0	0	0
PM_{10}	tons/yr	0	0	0	0	0	0	0	0	0
CO	tons/yr	0	0	0	0	0	0	0	0	0
NOx	tons/yr	0	0	0	0	0	0	0	0	0
Pb	tons/yr	0	0	0	0	0	0	0	0	0
Hg	tons/yr	0	0	0	0	0	0	0	0	0
CO2	tons/yr	0	0	0	0	0	0	0	0	0
HEARTLAND[1]										
SO2	tons/yr	0	0	0	0	0	0	0	0	0
PM_{10}	tons/yr	0	0	0	0	0	0	0	0	0
CO	tons/yr	0	0	0	0	0	0	0	0	0
NOx	tons/yr	0	0	0	0	0	0	0	0	0
Pb	tons/yr	0	0	0	0	0	0	0	0	[illegible]
Hg	tons/yr	0	0	0	0	0	0	0	0	[illegible]
CO2	tons/yr	0	0	0	0	0	0	0	0	[illegible]
MRES[1]										
SO2	tons/yr	0	0	0	0	0	0	0	0	[illegible]
PM_{10}	tons/yr	0	0	0	0	0	0	0	0	[illegible]
CO	tons/yr	0	0	0	0	0	0	0	0	[illegible]
NOx	tons/yr	0	0	0	0	0	0	0	0	[illegible]
Pb	tons/yr	0	0	0	0	0	0	0	0	[illegible]
Hg	tons/yr	0	0	0	0	0	0	0	0	[illegible]
CO2	tons/yr	0	0	0	0	0	0	0	0	[illegible]
OTP[1]										
SO2	tons/yr	0	0	0	0	0	0	0	0	[illegible]
PM10	tons/yr	3.66	0	0	0	0	0	0	0	[illegible]
CO	tons/yr	15.75	0	0.63	0	0	0	0	0	[illegible]
NOx	tons/yr	0	0	0	0	0	0	0	0	[illegible]
Lead	tons/yr	0	0	0	0	0	0	0	0	[illegible]
Hg	tons/yr	0	0	0	0	0	0	0	0	[illegible]
CO2 - RURAL MN	tons/yr	25014.93	0	0	0	0	0	0	0	[illegible]
CO2 - WITHIN 200 MILES OF MN	tons/yr	0	0	0	0	0	0	0	0	[illegible]
ORE[1]										
SO2	tons/yr	0	0	0	0	0	0	0	0	
PM_{10}	tons/yr	0	0	0	0	0	0	0	0	
CO	tons/yr	0	0	0	0	0	0	0	0	
NOx	tons/yr	0	0	0	0	0	0	0	0	
Pb	tons/yr	0	0	0	0	0	0	0	0	
Hg	tons/yr	0	0	0	0	0	0	0	0	
CO2	tons/yr	0	0	0	0	0	0	0	0	
SMMPA[1]										
SO2	tons/yr	0	0	0	0	0	0	0	0	
PM_{10}	tons/yr	0	0	0	0	0	0	0	0	
CO	tons/yr	0	0	0	0	0	0	0	0	
NOx	tons/yr	0	0	0	0	0	0	0	0	
Pb	tons/yr	0	0	0	0	0	0	0	0	
Hg	tons/yr	0	0	0	0	0	0	0	0	
CO2	tons/yr	0	0	0	17,005.58	0	0	16,660.12	3,658.44	13,063.7

BSPII and Alternate Incremental Emission Summary by Applicant

			2011	2012	2013	2014	2015	2016	2017	2018	201
WITH BSPII OPTION											
MDU[1]											
SO2	tons/yr		0	0	0	0	0	0	0	0	[illegible]
PM_{10}	tons/yr		0	0	0	0	0	0	0	0	[illegible]
CO	tons/yr		0	0	0	0	0	0	0	0	[illegible]
NOx	tons/yr		0	0	0	0	0	0	0	0	[illegible]
Pb	tons/yr		0	0	0	0	0	0	0	0	[illegible]
Hg	tons/yr		0	0	0	0	0	0	0	0	[illegible]
BSPII[2]											
Capacity	MW	600.00									
Capacity Factor	%	88%									
Projected Energy	MWh		4,625,280	4,625,280	4,625,280	4,625,280	4,625,280	4,625,280	4,625,280	4,625,280	4,625,280
SO2	lb/MWh	0.47									
PM_{10}	lb/MWh	0.28									
CO	lb/MWh	0.94									
NOx	lb/MWh	0.47									
Pb	lb/MWh	0.000074									
Hg	lb/MWh	0.000023									
CO2	lb/MWh	1927.24									
SO2	tons/yr		1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.0
PM_{10}	tons/yr		651.61	651.61	651.61	651.61	651.61	651.61	651.61	651.61	651.6
CO	tons/yr		2,172.03	2,172.03	2,172.03	2,172.03	2,172.03	2,172.03	2,172.03	2,172.03	2,172.0
NOx	tons/yr		1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.02	1,086.0
Pb	tons/yr		0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.1
Hg	tons/yr		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.0
CO2	tons/yr		4,457,008.61	4,457,008.61	4,457,008.61	4,457,008.61	4,457,008.61	4,457,008.61	4,457,008.61	4,457,008.61	4,457,008.6
BSPI (41% owned by other than OTP)[3]											
Ownership not held by OTP	%	41%									
Projected Energy	MWh		1,341,117	1,341,464	1,342,993	1,344,105	1,205,053	1,347,510	1,347,510	1,347,510	1,347,51
		2010 and prior	2011 and going forward								
SO2	lb/MWh	7.27	0.70								
PM_{10}	lb/MWh	0.0010	0.0010								
CO	lb/MWh	0.33	0.33								
NOx	lb/MWh	9.44	9.44								
Pb	lb/MWh	0.000000310	0.000000310								
Hg	lb/MWh	0.0000495	0.0000495								
CO2	lb/MWh	2331.0	2331.0								
SO2	tons/yr		469.39	469.51	470.05	470.44	421.77	471.63	471.63	471.63	471.
PM_{10}	tons/yr		0.67	0.67	0.67	0.67	0.60	0.67	0.67	0.67	0.
CO	tons/yr		219.27	219.33	219.58	219.76	197.03	220.32	220.32	220.32	220.
NOx	tons/yr		6,330.07	6,331.71	6,338.93	6,344.18	5,687.85	6,360.25	6,360.25	6,360.25	6,360.
Pb	tons/yr		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.
Hg	tons/yr		0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.
CO2	tons/yr		1,563,071.80	1,563,476.77	1,565,258.60	1,566,554.48	1,404,488.74	1,570,523.10	1,570,523.10	1,570,523.10	1,570,523.
Incremental											
SO2	tons/yr		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.
PM_{10}	tons/yr		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.
CO	tons/yr		0.00	0.00	0.00	0.00	0.02	0.02	0.00	0.03	0.
NOx	tons/yr		0.00	0.00	0.00	0.00	0.66	0.66	0.00	0.98	0.
Pb	tons/yr		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.
Hg	tons/yr		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.
CO2	tons/yr		0.00	0.00	0.00	0.00	161.98	161.98	0.00	242.98	161.

21122

BSPII and Alternate Incremental Emission Summary by Applicant

		2011	2012	2013	2014	2015	2016	2017	2018	201
ALTERNATE OPTION[1]										
CMMPA										
SO_2	tons/yr	358.34	614.30	614.30	614.30	614.30	614.30	614.30	614.30	614.3
PM_{10}	tons/yr	21.50	36.86	36.86	36.86	36.86	36.86	36.86	36.86	36.8
CO	tons/yr	48.86	83.77	83.77	83.77	83.77	83.77	83.77	83.77	83.7
NO_x	tons/yr	26.06	44.68	44.68	44.68	44.66	44.68	44.68	44.68	44.6
Pb	tons/yr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Hg	tons/yr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0
CO_2	tons/yr	119,815.45	205,397.91	205,397.91	205,397.91	205,397.91	205,397.91	205,397.91	205,397.91	205,397.9
HEARTLAND										
SO_2	tons/yr	529.98	529.98	529.98	529.98	529.98	529.98	529.98	529.98	529.9
PM_{10}	tons/yr	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.8
CO	tons/yr	72.21	72.21	72.21	72.21	72.21	72.21	72.21	72.21	72.2
NO_x	tons/yr	38.54	38.54	38.54	38.54	38.54	38.54	38.54	38.54	38.5
Pb	tons/yr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Hg	tons/yr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0
CO_2	tons/yr	177206.04	177206.04	177206.04	177206.04	177206.04	177206.04	177206.04	177206.04	177206.0
MRES										
SO_2	tons/yr	583.58	1406.04	1285.77	924.11	777.16	804.59	961.89	1081.36	1039.0
PM_{10}	tons/yr	46.58	95.98	88.03	123.83	136.40	132.97	147.40	149.33	146.
CO	tons/yr	93.27	205.39	188.13	467.19	567.03	565.83	592.05	602.15	596.1
NO_x	tons/yr	87.20	147.21	135.62	259.16	304.62	286.87	317.97	306.35	302.5
Pb	tons/yr	0.00	0.00	0.00	0.02	0.03	0.03	0.03	0.03	0.0
Hg	tons/yr	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.0
CO_2	tons/yr	248,652.89	523,887.85	480,268.27	771,718.28	874,662.89	860,969.18	936,042.32	951,748.61	936,797.
OTP										
SO_2	tons/yr	6298.00	6520.47	6480.35	6528.57	5880.51	6507.04	6522.09	6420.41	6362.
PM10	tons/yr	0.00	18.66	16.86	20.60	23.70	19.67	19.44	4.23	0.
CO	tons/yr	0.00	9.50	0.00	9.87	15.26	5.71	12.07	9.61	0.
NO_x	tons/yr	19.96	119.82	104.89	109.08	115.30	88.15	85.94	18.33	11.
Lead	tons/yr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.
Hg	tons/yr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.
	tons/yr									
CO_2	tons/yr									
CO_2 - RURAL MN	tons/yr	0.00	48,939.55	33,844.21	55,118.71	63,598.83	47,797.78	55,023.60	36,730.15	14,679.
CO_2 - WITHIN 200 MILES OF MN	tons/yr	5,080.93	10,521.45	6,244.02	4,803.12	5,524.73	14.03	282.60	1,628.55	1,462.
GRE										
(2014 alternate generation)										
Energy	MWh	0.00	0.00	0.00	894,220.80	894,220.80	894,220.80	894,220.80	894,220.80	894,220.
SO_2	lb/MWh	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.
SO_2	tons/yr	0.00	0.00	0.00	209.96	209.96	209.96	209.96	209.96	209.
PM_{10}	tons/yr	140.92	140.92	140.92	125.98	125.98	125.98	125.98	125.98	125.
CO	tons/yr	335.06	335.06	335.06	671.88	671.88	671.88	671.88	671.88	671.
NO_x	tons/yr	185.73	185.73	185.73	209.96	209.96	209.96	209.96	209.96	209.
Pb	tons/yr	0.00	0.00	0.00	0.08	0.08	0.08	0.08	0.08	0.
Hg	tons/yr									
CO_2	tons/yr	803,843.53	803,843.53	803,843.53	896,122.27	896,122.27	896,122.27	896,122.27	896,122.27	896,122.

2123

BSPII and Alternate Incremental Emission Summary by Applicant

			2011	2012	2013	2014	2015	2016	2017	2018	2019
ALTERNATE OPTION [5]											
SMMPA											
SO2	tons/yr		765.72	821.84	828.74	772.60	849.22	858.21	837.96	869.84	871.69
PM_{10}	tons/yr		508.59	525.41	567.59	672.95	749.31	782.99	801.72	828.00	840.64
CO	tons/yr		148.02	163.98	156.39	122.44	140.30	131.83	114.46	118.19	111.41
NOx	tons/yr		297.83	304.68	290.65	114.87	163.70	136.18	61.44	88.99	100.40
Pb	tons/yr		0.10	0.10	0.10	0.00	0.00	0.10	0.00	0.10	0.00
Hg	tons/yr		0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
CO2	tons/yr		18,243.60	51,787.54	42,546.85	0.00	27,528.54	15,979.56	0.00	0.00	0.00
MDU											
SO2	tons/yr		310.05	310.05	310.05	310.05	310.05	310.05	310.05	310.05	310.05
PM_{10}	tons/yr		224.38	224.38	224.38	224.38	224.38	224.38	224.38	224.38	224.38
CO	tons/yr		1,256.53	1,256.53	1,256.53	1,256.53	1,256.53	1,256.53	1,256.53	1,256.53	1,256.53
NOx	tons/yr		733.88	733.88	733.88	733.88	733.88	733.88	733.88	733.88	733.88
Pb	tons/yr		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Hg	tons/yr		0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
CO2	tons/yr		1,802,851.05	1,802,851.05	1,802,851.05	1,802,851.05	1,802,851.05	1,802,851.05	1,802,851.05	1,802,851.05	1,802,851.05
BSPI (41% owned by other than OTP) [4]											
Ownership not held by OTP	%	41%									
Projected Energy	MWh		1,347,232	1,347,232	1,347,232	1,347,232	1,204,914	1,347,371	1,347,510	1,347,302	1,347,371
		All years									
SO2	lb/MWh	7.27									
PM_{10}	lb/MWh	0.0010									
CO	lb/MWh	0.33									
NOx	lb/MWh	9.44									
Pb	lb/MWh	0.000000310									
Hg	lb/MWh	0.0000495									
CO2	lb/MWh	2331.0									
SO2	tons/yr		4,897.19	4,897.19	4,897.19	4,897.19	4,379.86	4,897.89	4,898.20	4,897.44	4,897.6
PM_{10}	tons/yr		0.67	0.67	0.67	0.67	0.60	0.67	0.67	0.67	0.6
CO	tons/yr		220.27	220.27	220.27	220.27	197.00	220.30	220.32	220.28	220.3
NOx	tons/yr		6,358.94	6,358.94	6,358.94	6,358.94	5,687.19	6,359.59	6,360.25	6,359.26	6,359.5
Pb	tons/yr		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Hg	tons/yr		0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.0
CO2	tons/yr		1,570,199.13	1,570,199.13	1,570,199.13	1,570,199.13	1,404,326.75	1,570,361.12	1,570,523.10	1,570,280.13	1,570,361.1
Incremental											
SO2	tons/yr		4,427.60	4,427.68	4,427.14	4,426.75	3,958.09	4,426.07	4,426.57	4,425.81	4,426.0
PM_{10}	tons/yr		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.(
CO	tons/yr		1.00	0.94	0.69	0.51	0.00	0.00	0.00	0.00	0.(
NOx	tons/yr		28.86	27.22	20.01	14.76	0.00	0.00	0.00	0.00	0.(
Pb	tons/yr		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.(
Hg	tons/yr		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.(
CO2	tons/yr		7,127.33	6,722.37	4,940.53	3,644.66	0.00	0.00	0.00	0.00	0.(

NOTES

[1] Emissions for CMMPA, Heartland, MDU, and GRE resources other than BSPII are not provided. The BSPII emissions are included in the BSPII line item for each pollutant.

[2] Emissions provided by MRES, OTP, and SMMPA are the incremental emissions from their respective resources other than BSPII. The BSPII emissions are included in the BSPII line item for each pollutant.

[3] Emissions provided for BSPII are calculated based on a 600 MW plant with an 88 percent capacity factor. The rates at which emissions are generated are shown in Table 10.

[4] Includes BSPI emissions for percentage share ownership held by parties other than Otter Tail Power. BSPI emission for percentage share ownership held by Otter Tail Power is included in Otter Tail Power's emissions estimates

[5] Emissions provided by all of the applicants are the incremental emissions for the best individual alternative option.

Appendix B
Minnesota Public Utilities Commission Externality Values

RECEIVED

STATE OF MINNESOTA PUBLIC UTILITIES COMMISSION

April 27, 2005

To: Service List

From: Burl W. Haar
Executive Secretary

Re: In the Matter of the Investigation into Environmental and Socioeconomic Costs

Docket Nos. E-999/CI-93-583
E-999/CI-00-1636

NOTICE OF UPDATED ENVIRONMENTAL EXTERNALITY VALUES

In its May 3, 2001 ORDER UPDATING EXTERNALITY VALUES AND AUTHORIZING COMMENT PERIODS ON CO_2, $PM_{2.5}$, AND APPLICATION OF EXTERNALITY VALUES TO POWER PURCHASES, the Commission used the Gross National Product Price Deflator Index to update the externality values adopted in its July 3, 1997 Order in Docket No. E-999/CI-93-583, and indicated that the values will continue to be updated as data becomes available from that index.

The values have been updated through 2004. A copy of the updated values has been attached to this notice and can be found on the Commission's Website.

Questions regarding this matter may be directed to David Jacobson at 651-297-4562, or Clark Kaml at (651) 297-4563.

This information can be made available in alternative formats (i.e., large print or audio tape) by calling (651) 297-4596 (voice), or 1-800-627-3529 (TTY relay service).

Enc.

ENVIRONMENTAL EXTERNALITIES VALUES
UPDATED THROUGH 2004

URBAN

	Original (1995 $/ton)		INFLATION ADJUSTED GDPI (2004 $/ton)	
SO_2	112	189	0	0
PM_{10}	4462	6423	5243	7548
CO	1.06	2.27	1.25	2.67
NO_x	371	978	436	1149
Pb	3131	3875	3679	4554
CO_2	0.3	3.1	0.35	3.64

METROPOLITAN FRINGE

	Original (1995 $/ton)		INFLATION ADJUSTED GDPI (2004 $/ton)	
SO_2	46	110	0	0
PM_{10}	1987	2886	2335	3391
CO	0.76	1.34	0.89	1.57
NO_x	140	266	165	313
Pb	1652	1995	1941	2344
CO_2	0.3	3.1	0.35	3.64

RURAL

	Original (1995 $/ton)		INFLATION ADJUSTED GDPI (2004 $/ton)	
SO_2	10	25	0	0
PM_{10}	562	855	660	1005
CO	0.21	0.41	0.25	0.48
NO_x	18	102	21	120
Pb	402	448	472	526
CO_2	0.3	3.1	0.35	3.64

WITHIN 200 MILES OF MINNESOTA

	Original (1995 $/ton)		INFLATION ADJUSTED GDPI (2004 $/ton)	
SO_2	10	25	0	0
PM_{10}	562	855	660	1005
CO	0.21	0.41	0.25	0.48
NO_x	18	102	21	120
Pb	402	448	472	526
CO_2	0	0	0	0

Note: In the January 3, 1997 Order Establishing Environmental Cost Values the Commission found that SO_2 damages would be internalized after 2000 and applying externality costs would be unwarranted.