



414 Nicollet Mall
Minneapolis, MN 55401

April 19, 2010

— VIA E-MAIL & U.S. MAIL —

Darrell Nitschke
Director of Administration and Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

**Re: IN THE MATTER OF AN APPLICATION FOR ADVANCE DETERMINATION
OF PRUDENCE FOR TWO PRAIRIE ISLAND NUCLEAR PLANT PROJECTS:
NEW UNIT 2 STEAM GENERATORS AND UNITS 1 AND 2 EXTENDED POWER
UPDATES, CASE NO. PU 10-_____**

Dear Mr. Nitschke:

In accordance with Section 69-02-09-02 of the North Dakota Administrative Code, enclosed is one copy of Northern States Power Company's, a Minnesota Corporation operating in North Dakota ("Xcel Energy," "NSP-M" or the "Company") filing in the above referenced application.

This application requests an Advanced Determination of Prudence ("ADP") on two significant investments the Company is making at our Prairie Island Nuclear Generating Plant ("Prairie Island") located in Red Wing, Minnesota. The significant investments are for new steam generators for Unit 2 and the 164 megawatt capacity expansion project referred to as an extended power uprate. The new steam generators are one component of a larger effort to extend the operating life of Prairie Island an additional 20 years.

To provide context to these efforts, the application contains a comprehensive review of all our nuclear investments necessary to extend the operating life and increase the generating capacity at both our Monticello and Prairie Island nuclear generating plants. However, for reasons explained in the application, we are only requesting an ADP on the two specific components of our overall nuclear investments.

Darrell Nitschke

April 19, 2010

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We believe this approach is consistent with the recent rate case settlement and our on-going commitment to fully inform the Commission of facilities that will affect future electric rates of our North Dakota customers.

Included with this application is our filing fee of \$125,000 and a signed affidavit supporting the truthfulness of our statements. All information contained in this filing is public information.

We look forward to working with the Commission in the review of this filing and respectfully request that the Commission make a determination that the new Prairie Island Unit 2 steam generators and the extended power uprates at Unit 1 and 2 meet the Advance Determination of Prudence requirement of N.D.C.C. § 49-05-16.

SINCERELY,

/s/

JAMES R. ALDERS
DIRECTOR, REGULATORY ADMINISTRATION

Enclosures

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN APPLICATION FOR)
ADVANCE DETERMINATION OF PRUDENCE)
FOR TWO PRAIRIE ISLAND NUCLEAR PLANT)
PROJECTS: NEW UNIT 2 STEAM)
GENERATORS AND UNITS 1 AND 2)
EXTENDED POWER UPRATES)

CASE No. PU-_____

**AFFIDAVIT OF
Brian R. Zelenak**

I, the undersigned, being first duly sworn, on oath depose and say that I am a Manager in Regulatory Administration for Northern States Power Company, a Minnesota corporation (the "Company") operating in North Dakota, and the applicant herein; that I have read the foregoing request For Advance Determination of Prudence for the Prairie Island Nuclear Generating Plant Projects: New Unit 2 Steam Generators and Unit 1 and 2 Extended Power Uprate, and I believe all statements therein to be true and correct; and that said filing is submitted and signed on behalf of said Company with the consent and authority of the Company.

/s/

Brian R. Zelenak

Subscribed and sworn to before me, this 16th day of April 2010.

/s/

Notary Public

My Commission Expires:

**STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION

CASE No. PU-_____

IN THE MATTER OF AN APPLICATION
FOR ADVANCE DETERMINATION OF
PRUDENCE FOR THE PRAIRIE ISLAND
NUCLEAR PLANT LIFE EXTENSION
AND EXTENDED POWER UPRATE
PROJECTS

I. INTRODUCTION

Northern States Power Company, a Minnesota Corporation operating in North Dakota (“Xcel Energy,” “NSP-M” or the “Company”), respectfully submits to the North Dakota Public Service Commission (the “Commission”) this Application for an Advance Determination of Prudence (“ADP” or “Application”) pursuant to North Dakota Century Code (“N.D.C.C.”) § 49-05-16 (also herein referred to as the “ADP Statute”). In this application the Company seeks the Commission’s determination that it is reasonable and prudent to replace, as part of our program of investments to extend the life of the Prairie Island Nuclear Generating Plant (“Prairie Island”), the Unit 2 steam generators at the plant and our planned investments to increase the production capacity of Prairie Island by approximately 164 megawatts.

As discussed more fully below, the life extension and increase in capacity of Prairie Island (also referred to herein as an extended power uprate (“EPU”)) will provide benefits to our customers, fully meet the requirements of the ADP Statute, and, therefore, warrant the issuance of an ADP. In particular, the two projects:

- Provide a safe and reliable source of base load electric energy;
- Are the least-cost options to provide additional generation necessary to meet our customers’ needs; and

- Ensure and expand the diversity of the Company's electric generation portfolio.

II. OVERVIEW

Xcel Energy operates two nuclear power plants. The Monticello Nuclear Generating Plant ("Monticello") is a 600 MW facility located in Monticello, Minnesota. It began operation in 1970. Prairie Island is a 1,100 MW facility located in Red Wing, Minnesota. The two units at Prairie Island began operating in 1973 and 1974. Our nuclear plants are among the most reliable, economical and efficient base load generating resources on our system. Together they produce approximately 28 percent of all the electrical energy used by our customers across the five states we serve in the Upper Midwest.

Nuclear power plants are initially licensed to operate by the federal Nuclear Regulatory Commission ("NRC") for a term of 40 years. Before the plants can continue to operate beyond their original licensed life, the NRC must grant extensions to operating licenses, for up to 20 year terms.

Over the last several years, as part of our Resource Planning efforts, Xcel Energy has evaluated the performance of Monticello and Prairie Island; including the determination of what investments are necessary to keep the plants operating safely and efficiently. From these analyses we have concluded that the cost of power to our customers will be much more economical if we extend the lives of the nuclear plants. Furthermore, we have determined that modifications can be made to safely increase production capacity at both plants. Extending the lives of the plants and increasing their production are much more economical solutions to reliably produce electricity than the alternatives.

Our program of life extension and increased production capacity at Monticello is well underway. On November 8, 2006 the NRC granted an extension of 20 years (to 2030) to the Monticello operating license. In the fall of 2006, state and federal regulators authorized the construction of an Independent Spent Fuel Storage Installation ("ISFSI") to accommodate an additional 20 years of operation. Construction of the ISFSI has been completed and ten containers of spent fuel have been moved to the on site dry storage facility. Some of the improvements necessary to increase Monticello's production capacity, by

approximately 71 MW, were made during the 2009 refueling outage and the remainder are scheduled for the 2011 refueling outage.

The ADP Statute allows the utility the ability obtain the Commission's view of major projects prior to the utility making substantial commitments. The significant investments we are making in our nuclear plants fit well with the intent of the statute. In this petition we are not requesting an ADP for investments at Monticello since much of the initial capital investment associated with life extension and EPU have been made or are well underway.¹ Nonetheless, in order to provide the Commission with a complete overview of our nuclear investment program, we have included a discussion of life extension and capacity increases at Monticello, as well as the analysis that demonstrates the Monticello projects are cost effective. (Section II, Attachment C)

Both the Unit 2 steam generator replacement component of the Prairie Island life extension and the capacity improvements at Prairie Island are at earlier stages that better lend themselves to the ADP review process. The steam generator replacements are scheduled for 2013. Without replacing the steam generators, the plant's life cannot be extended and the associated benefits cannot be realized. Replacement of the Unit 2 steam generators will cost an estimated \$259 million.² Increases in generating capacity at the plant, amounting to 164 MW, are currently scheduled for 2014 and 2015 and represent investments of \$330 million.

Federal and state approvals necessary for life extension at Prairie Island are currently pending. The NRC's consideration of our operating license renewal request is underway, but not yet complete. Minnesota regulators have authorized the spent fuel storage necessary to extend the life of the plant, but the approval is stayed until June 1, 2010, when the state legislative session ends. Once the NRC approves an extension to the operating license, we plan to file for the approvals necessary to increase the plant's generating capacity.

¹ We note that the investments related to Monticello were either made or planned prior to the settlement of our last electric rate case, Case No. PU-07-776, which was approved by the Commission on December 31, 2008.

² The Unit 1 steam generators were replaced in 2004.

In determining whether to continue to operate Prairie Island for an additional 20 years and increase its capacity, we performed comprehensive analyses that included estimates of costs associated with life extension - not just the steam generator costs - and all the capacity expansion costs. The analyses demonstrate power production costs will be significantly lower with continued and increased generation at Prairie Island compared to the alternatives, which results in cost savings to our customers when compared to other generation alternatives.

In addition to the economic benefits, the projects also utilize existing generating plants and utility infrastructure, thereby minimizing the incremental environmental footprint. The projects ensure continued diversity in the Company's generation portfolio, and diversification of resources promotes price stability for customers by providing a hedge against fossil fuel price volatility and the possibility of future environmental regulations.

Based on the above, the life extension and generation increases at Prairie Island are reasonable and prudent because they allow us to maintain reliable, least cost generating resources in our fleet and produce greater amounts of cost-effective electrical power well into the future.

III. DESCRIPTION OF APPLICANT

Northern States Power Company (Xcel Energy) is a Minnesota corporation duly authorized to conduct business in the State of North Dakota as a public utility subject to the jurisdiction and regulation of the Commission pursuant to Title 49 of the N.D.C.C. The full name and address of the Company is:

Northern States Power Company,
414 Nicollet Mall
Minneapolis, Minnesota 55401

The Company also operates in North Dakota from the following address:

Northern States Power Company
2302 Great Northern Drive
Fargo, ND 58102

Xcel Energy's Certificate of Incorporation and amendments were filed with the Commission on September 30, 2009 and are incorporated herein by reference.

The Company presently serves approximately 87,000 retail electric customers in and around Fargo, Grand Forks, and Minot, North Dakota and owns approximately 250 miles of transmission lines and 12 substations in North Dakota. Xcel Energy and its affiliate, Northern States Power Company, a Wisconsin corporation (“NSP-W”), operate an integrated utility system and service territory in five Upper Midwest states including North Dakota.

IV. DESCRIPTION OF NUCLEAR INVESTMENTS

In this section of our filing we provide a brief background discussion that describes the Monticello and Prairie Island power plants, a discussion of the investments necessary to extend the life of the two power plants, and a description to the changes necessary to capture the benefits of increased generating capacity at both plants. Our purpose is to provide information about the particular projects related to our ADP request and the context within which those projects occur. However, this ADP request is limited to two major discrete investments related to Prairie Island.

A. Background

Prairie Island and Monticello provide highly reliable and low-cost base load service, operating at full capacity around the clock for extended periods of time. These two nuclear plants produce over 28 percent of the electric energy used by our customers in the Company’s NSP System which serves five states in the Upper Midwest.

1. Monticello Nuclear Generating Plant

Monticello is located on approximately 2,150 acres and is within the city limits of Monticello, Minnesota, approximately 50 miles northwest of Minneapolis/St. Paul. Part of the property is on the eastern bank of the Mississippi River in Sherburne County and part is on the western bank in Wright County.

Monticello uses nuclear fuel in a single-unit boiling water reactor to produce 600 MW of electrical power. Its generating capacity is enough to serve about 500,000 homes, and during the years 2005 through 2009, the plant maintained an average capacity factor of 90.9 percent. In January 2006, Monticello reached 637 consecutive days of operation, the longest run in plant history, and

generated a record 5,070,000 megawatt-hours of electricity, eclipsing its prior record set in 2004. For 2008, the actual capacity factor was 95.0 percent.

Monticello received its initial operating license from the NRC in September 1970. The initial license was for a period of 40 years and was to expire in 2010. In March 2005 the Company filed to renew the operating license and in the fall of 2006 the NRC renewed the initial license for an additional 20 years, to September 2030.

In January 2005, the Company filed a Certificate of Need application with the Minnesota Public Utilities Commission (“MPUC”) to build an ISFSI to store 30 dry storage casks to support an additional 20 years of operation (Docket E002/CN-05-123). After a contested case proceeding, the MPUC granted the Certificate on October 23, 2006. After legislative review, the MPUC’s decision became effective June 1, 2007.

The ISFSI was constructed in 2007/2008. Ten casks were loaded and placed in the ISFSI in 2008. The next 10 casks are scheduled to be loaded and placed on the ISFSI in 2013 and the last 10 are scheduled for 2016.

The Monticello ISFSI consists of a lighted area, approximately 460 feet long and 200 feet wide, roughly 3½ acres in size, located adjacent to the reactor and turbine building. Two fences surround the facility with a monitored clear zone between. Within the storage area, spent fuel canisters are stored in modular concrete vaults, placed on a reinforced concrete pad, 18 to 24 inches thick. Concrete approach pads surround the support pad to accommodate vault placement and spent fuel canister transfer traffic. A small concrete building approximately 20 by 20 feet is located within the ISFSI to house electrical equipment. The site and storage vaults are monitored with cameras, other security devices and temperature sensors. An access road connects the ISFSI to the rest of the plant. The ISFSI currently contains ten loaded casks as shown in Figure 1 below.

Figure 1: Monticello Plant and ISFSI



In November 2008 we filed an application with the NRC to amend the renewed operating license to allow operation at an increased generating capacity of approximately 71 MW. We are currently working with the NRC on the application and expect a decision in late 2010 or early 2011.

2. Prairie Island Nuclear Generating Plant

Prairie Island is located within the city limits of Red Wing, Minnesota, approximately 30 miles southeast of Minneapolis/St. Paul. The Prairie Island site consists of approximately 560 acres. A perimeter fence and other barriers restrict access to Prairie Island.

Prairie Island uses nuclear fuel in two, two-loop pressurized water reactors to produce approximately 550 MW of electrical power per unit.

Prairie Island has performed well during its 36 years of operation and is a highly reliable generation resource. Over the past 5 years (2005 through 2009) Prairie Island has maintained an average capacity factor of 86.9 percent. In 2007, Prairie Island's capacity factor was 93.85 percent and generated a record of nearly 9 million megawatt-hours of electricity, eclipsing its prior record set in 2003.

Unit 1 was granted its initial operating license by the NRC in August 1973 and Unit 2 received its initial operating license in October 1974. Unit 1 began commercial operation in December 1973, and Unit 2 began operation in December 1974. Units 1 and 2 are currently licensed by the NRC to operate until August 9, 2013 and October 29, 2014, respectively.

On April 15, 2008, the Company filed a request with the NRC to renew Prairie Island's operating licenses for an additional 20 years (to 2033 for Unit 1 and 2034 for Unit 2). We anticipate that the NRC will approve renewal of the Prairie Island operating licenses in late 2010. We intend to file an application with the NRC for an amendment to the operating license to implement the extended power uprate following the NRC's renewal of the plant's operating license.³

Inside the plant, spent fuel is stored in a 38-foot deep pool for approximately 10 to 12 years in order to allow it to cool before being loaded into dry storage casks. In 1995, a dry storage facility or ISFSI was built on the plant site to provide adequate dry storage capacity to allow the plant to continue to operate. The Prairie Island ISFSI, which consists of a lighted area approximately 720 feet long and 340 feet wide, roughly 5½ acres in size, is located west of the Prairie Island Plant cooling towers within the 560-acre site. Within the ISFSI, the dry storage casks are currently stored on two reinforced concrete pads, which are 36' x 216' x 3'. A 17-foot high earthen berm surrounds the ISFSI. See Figure 2 below.

The Prairie Island ISFSI is currently licensed by the NRC for 48 TN-40 casks. However, Minnesota statutes restricted the number of casks. In 2003 the Minnesota legislature authorized the use of dry casks to support operation until the end of the current plant operating licenses in 2013 and 2014. The estimated number casks needed to support operation until 2013 and 2014 is 29 casks.

³ A decision on the license renewal is necessary before the Company may file for a license amendment for the EPU.

Figure 2: Prairie Island Plant and ISFSI



In order to ensure that Prairie Island can continue to operate through the 20-year license renewal period, through 2033 for Unit 1 and 2034 for Unit 2, an additional 35 casks are necessary, for up to a total of 64 dry storage casks in the ISFSI.⁴ In May 2008, the Company filed a Certificate of Need application with the MPUC to add up to 35 additional casks to the existing ISFSI and in December, 2009, the MPUC approved the request. The MPUC's decision is stayed through the state legislative session, but will become effective June 1, 2010 when the legislative session ends, in absence of further action.

B. Life Extension

1. Assessment Process

Nuclear plants are the most highly regulated facilities in the nation, with NRC inspectors on-site around the clock. Nuclear plants must be maintained in a condition that continues to evaluate any potential erosion of design and safety margins, regardless of how long the facility operates.

⁴ When the Prairie Island Plant shuts down and ceases operation, the inventory of assemblies in the reactors and pool must be removed to facilitate decommissioning. Assuming operation of the plant through 2033/2034, it will take a total of 98 casks to store all the spent fuel generated at the Prairie Island Plant in order to accommodate decommissioning if the federal government has not begun to remove spent fuel.

In considering whether to extend the operating licenses of the nuclear plants, we identified the status of plant components by reviewing the industry experiences of other nuclear plant operators, conducting and reviewing aging studies of system components, monitoring the performance of system components, participating in industry collaborations, undertaking risk assessments and incorporating the results of ongoing regulatory reviews to determine an estimate of the investments needed through the extended operating license period. The ongoing investments necessary to continue to safely and reliably operate the plants at the high capacity levels are referred to as “life cycle management” costs. Life cycle management includes: the routine operating and capital costs necessary to continue to safely and reliably operate the plant and the large capital investments, such as the steam generator replacements at Prairie Island Unit 2.

A number of aging management tools were used to assess whether the Monticello and Prairie Island plants could continue to operate safely and reliably for another 20 years. The following is a summary of the aging management tools used to ensure the Plants would continue to meet the NRC standards.

- A. Experience Reviews - Experience gained from the operation of other plants is entered into central data banks. The relevant events occurring at other similarly designed plants are continuously monitored by the plants to search for potentially applicable occurrences which may be precursors to future events at Monticello and Prairie Island. This provides an opportunity to look for signs of similar behavior and to implement preventive actions prior to failure. For instance, if piping corrosion or erosion is detected in one plant, other plants are alerted to proceed with additional inspection and testing to verify the absence of similar degradation and if found, implement early remedies to avoid failure, resulting in a possible plant shutdown and lost electric production.
- B. Aging Studies - The industry and NRC have conducted comprehensive aging studies for all major plant components to predict the degradation type, location and rate. With this knowledge, the plants adjust their maintenance practices to look for the initiation of degradation to discover any indication of aging and to repair or mitigate the effects. Areas of uncertain degradation are monitored periodically to detect the

- start of degradation, such as frequent wall thickness measurement of piping subject to corrosion thinning.
- C. Performance Monitoring - Plant systems are also monitored for performance with respect to reliability (standby safety systems), availability (continuous operating systems) and functional failures, as required by relevant NRC rules such as the Maintenance Rule (10 C.F.R. Part 50.65). Acceptance standards are established for each system and when exceeded, immediate corrective action must be taken to bring the system performance back into compliance. Through this process, equipment problems are caught early to allow timely corrective or preventive actions.
 - D. Industry Collaboration - Some of the equipment aging mechanisms affect many other plants with identical or similar equipment. In these instances, the affected plants join in efforts to find solutions to reduce or eliminate the degradation. These projects may be undertaken through Owners Groups (such as the Boiling Water Reactor Vessel and Internals Project) or the Electric Power Research Institute (such as the Materials Research Program). Monticello and Prairie Island frequently utilize industry programs to reduce individual plant costs and assure consistent implementation of fixes.
 - E. Risk Assessments - The Probabilistic Risk Assessment for the plants consists of a detailed model to reflect the current plant configuration. Using the model to analyze the risk associated with a variety of accident scenarios provides an insight as to the most important systems and components necessary to operate the plant in the safest way. Maintenance and reliability of these critical systems components is prioritized to assure that they remain functional under the different postulated accidents.
 - F. Regulatory Review - Ongoing regulatory review identifies operating events at other plants that can trigger new NRC mandates to replace equipment, implement new safety measures or enhance inspections. These mandates are not unique to license renewal and will apply to all plants affected by the new requirements and will maintain or improve the operating margins for all plants.

After conducting the rigorous investigations of the status of plant systems and equipment described above, the Company concluded that both nuclear power plants could continue to operate with a limited number of key investments and continuation of the ongoing capital program that has been part of plant maintenance since the beginning of operation.

In order to operate Monticello beyond its current operating license of 2010, the Company had to:

- Renew the operating license for an additional 20 years, until 2030;
- Replace or refurbish critical plant equipment to ensure that it is capable of performing safely and reliably through the next 20 years of its operating life; and
- Obtain the necessary state and federal approvals for the ISFSI and dry storage casks and construct the ISFSI and load ten casks (casks 11 through 30 will be loaded in the future).

To operate Prairie Island beyond its current operating licenses, which expire in 2013 and 2014, the Company must:

- Renew the operating licenses for Units 1 and 2 for an additional 20 years (until 2033 and 2034 for Units 1 and 2 respectively);
- Replace the steam generators at Unit 2 and replace or refurbish critical plant equipment to ensure that it is capable of performing safely and reliably through the next 20 years of its operating life; and
- Obtain the necessary state and federal approvals for the additional dry storage casks at the Prairie Island ISFSI to support 20 additional years of operating life.

Attachment A provides a listing of the various approvals necessary for the life extension and EPU projects at Prairie Island and Monticello and the status of each. Attachment B contains the estimated costs associated with each of the major components. The activities listed in Attachment B cannot be viewed in isolation: each activity is necessary to continue to operate the plants. The collective implementation of the activities listed under the Prairie Island and Monticello life extension headings in Attachment B are the foundation of the

economic analysis we performed that resulted in the decision to pursue the continued operation of the plants.

2. Monticello Life Extension

As noted above, in the case of Monticello's life extension project, many of the project activities have already taken place. The filing to renew the operating license was prepared, filed, and approved by the NRC. The state Certificate of Need filing to construct an ISFSI was filed in January 2005, approved in October 2006, and the ISFSI was constructed during 2007 and 2008, and ten casks were loaded in 2008. The main activities not already undertaken for Monticello's life extension project are the additional 20 casks that are scheduled to be loaded and placed in the ISFSI in 2013 and 2016 (ten each year) and other miscellaneous life cycle management projects.

The only other costs contained in Attachment B for the Monticello life extension project are capital costs for routine capital projects. It is estimated that approximately \$10 million will be spent annually on routine capital projects. The costs are based on past actual expenditures at Monticello and were included in the analysis when we evaluated the life extension. We include them in the economic analysis for an accurate comparison to the alternatives and acknowledge them here so the Commission becomes familiar with them.

3. Prairie Island Life Extension

The Prairie Island life extension project began in earnest with the preparation of a number of regulatory filings in 2006 and 2007. However, as Attachment B indicates, life extension is an ongoing process throughout the life of the plant and the actual costs incurred will span the next 25 years, until 2033 and 2034.

Steam generator replacements are one component of Prairie Island life extension.

Steam generators are large vessels that separate high-pressure water that has circulated through the reactor from the steam cycle used to power turbine generators at the plant. In the steam generator vessels, heat is transferred from the primary reactor water cycle to the secondary steam cycle by passing water through and around 3,388 steel alloy tubes.

Through an aggressive program of inspection and maintenance, Prairie Island has been able to operate its steam generators longer than other plants of similar

vintage. Steam generators on Unit 1 were replaced in 2004 after 31 years of operation. Replacement of the Unit 1 steam generators was cost-justified even had the plant only operated until 2013.

Unit 2 steam generators have experienced less overall degradation than the Unit 1 steam generators allowing them to remain in service until 2014, which is the end of Unit 2’s current license. However, it will be necessary to replace the Unit 2 steam generators in order to keep the plant operating economically beyond the current license period. Installation of the new steam generators is currently scheduled for Unit 2’s 2013 refueling outage (the last refueling outage prior to the current license expiration). Steam generator replacement is estimated to cost approximately \$259 million. The estimates of the project costs by year as required by N.D.C.C. § 49-05-16(1)(a) are contained in Attachment B.

Since we would not install new steam generators on Unit 2 unless we were going to continue to operate the plant another 20 years, all the costs for the continued operation of the Prairie Island must be included in the economic analysis – not just those of the steam generator. (See Attachment B) The annual levelized cost and estimated North Dakota allocation of the entire Prairie Island life extension project are listed below in Table 1.

Table 1: Prairie Island Life Extension Levelized Revenue Requirements

	Levelized Annual Revenue Requirements (thousands)
System Revenue Requirements	\$136,834,000
Allocation Factor	4.6449%
North Dakota Allocation	\$6,356,000

C. Generating Capacity Increases (or “EPUs”)

Several decades of reactor safety improvements, plant performance feedback, and improved fuel and core designs have shown that nuclear reactors throughout the country can operate at higher thermal output than allowed under the original NRC license while still remaining well within NRC calculated safe operational levels. Under NRC terminology, a power uprate of more than

seven percent (up to a maximum of 20 percent) over the original licensed thermal power (“OLTP”), and which requires significant balance-of-plant upgrades, is called an extended power uprate.

The Prairie Island EPU consists of a 164 MW (82 MW per unit) increase in generating capacity (approximate 10% increase in OLTP), and the Monticello EPU consists of a 71 MW increase in capacity (120% of the OLTP)⁵. Both EPUs will be accomplished by increasing the thermal power of the reactors -- resulting in an increase in steam production -- and improving the balance-of-plant equipment that converts the steam into electricity.

The EPU’s at the plants are multi-year projects that have both been divided into two implementation phases. This was due to the fact that the installations must be completed during refueling outages.

In 2008, we applied for and received the necessary state approvals to implement the EPU at Monticello and we expect to have the necessary NRC approvals by late 2010 or early 2011. We installed portions of the equipment necessary to gain the increase in capacity during the 2009 refueling outage and will install the remaining equipment during the 2011 outage.

EPUs in a pressurized water reactor like Prairie Island generally do not require significant modifications to the reactor or the nuclear steam supply system of the emergency core cooling system. However, the balance-of-plant systems that convert the steam produced in the steam generators to produce electricity will need significant modifications.

The generating capacity at Prairie Island will be expanded by: (1) increasing the thermal power produced by the reactors, which will increase the amount of steam produced in the steam generators; and (2) improving the balance-of-plant equipment that converts the steam into electricity. A higher thermal power level is achieved by increasing the amount of uranium in the reactor core, which will be accomplished by using fuel assemblies that contain slightly larger diameter uranium pellets than are currently used.

⁵ A power uprate was implemented at Monticello in 1998 which increased the reactor thermal power to 106% of the OLTP and resulted in an increase of 35 MWe capacity.

The modifications necessary will be completed on Unit 1 during the 2014 refueling outage and on Unit 2 during the 2015 refueling outage. In making the required changes, the following features have been incorporated to optimize thermal cycle efficiency under the new steam conditions and, therefore maximize gross megawatt output:

1. Upgrade High Pressure Turbines
2. Main Generator Rewinds
3. Replace Generator Step-Up Transformers
4. Upgrade Moisture Separator Reheaters
5. Upgrade Isophase Bus Duct Cooling

General operation of Prairie Island will not change after implementation of the EPU. The EPU costs are estimated at approximately \$330 million. Estimates of the project costs by year as required by N.D.C.C. § 49-05-16(1)(a) are contained in Attachment B.

The Prairie Island EPU annual levelized cost and estimated North Dakota allocation are listed in Table 2.

**Table 2: Prairie Island Extended Power Uprate
Levelized Revenue Requirements**

	Levelized Annual Revenue Requirements
System Revenue Requirements	\$36,702,000
Allocation Factor	4.6449%
North Dakota Allocation	\$1,705,000

D. Schedules and Cost Estimates

The individual activities in Attachment B are organized into a life extension and an EPU at each plant. Table 3 below identifies the four main components that encompass our nuclear investment decisions to extend the operation and increase the capacity of the plants. Each of the four project areas was the subject of extensive economic analysis. The time period is the period over which the projects will be implemented and the estimated capital dollars for the

projects (2007 dollars).⁶ Table 3 also indicates the portion of each project included in this ADP and its estimated allocation to North Dakota.

Table 3: Project Timeline and Cost (millions)

Project	Timeframe	Project Cost	Included in ADP	ND Allocation of ADP Capital Costs (4.6449%)
Prairie Island Life Extension	2007-2034	\$1,313	\$259	\$12
Prairie Island Extended Power Uprate	2007-2015	\$330	\$330	\$15
Monticello Life Extension	2005-2030	\$401	\$0	
Monticello Extended Power Uprate	2006-2011	\$130	\$0	
Total Nuclear Investments for Life Extension and EPU		\$2,274	\$589	\$27

E. Benefits of Nuclear Investments

Continuing to maintain a nuclear component to our generation resource mix provides significant benefits to our customers and the region. We provide the analysis and resulting benefits discussions for the life extension and EPU projects at both Prairie Island and Monticello to provide a comprehensive review of our nuclear asset management plan. As previously explained, while we are only seeking an ADP determination for the steam generator replacements and the EPU at Prairie Island, all the projects and their individual components should be considered when assessing the prudence and reasonableness to implement the nuclear asset management plan.

⁶ Some dollars already spent were not escalated; instead the actual dollars spent were included. See Attachment B notes for details.

- *Economic benefits.* Extending the operating life of Monticello and Prairie Island an additional 20 years and increases in generating capacity helps the Company meet our customers' growing energy needs in the most cost-effective manner. The projects provide a safe and reliable source of low-cost, base load electric energy to serve our customers' needs. The projects could only be reliably replaced by more expensive sources. Several alternatives for replacing Monticello and Prairie Island and expanding generating capacity were considered and found to be more expensive. The continued operation of Monticello and Prairie Island and increasing generating capacity will assist in maintaining diversity in the Company's generation portfolio. Diversification of resources provides price stability for customers by providing a hedge against exposure to increases in fossil fuel prices.
- *Environmental benefits.* The continued operation of Monticello and Prairie Island and increasing generating capacity will occur within the existing plant and ISFSI footprints, thereby utilizing the existing generation sites and electric transmission infrastructure. The continued and increased use of existing resources and their sites provide environmental benefits over new construction. The continued operation of Monticello and Prairie Island will provide carbon-free base load power and the implementation of the EPU's will lead to reduced carbon emissions compared to the alternatives.⁷ Moreover, maintaining diversification of resources provides a hedge against exposure to the possibility of future carbon regulation.

The economic assessments of continuing to operate Prairie Island and implementing the extended power uprate at Prairie Island are found in the Assessment of Prudence and Reasonableness, Section VI. The economic assessments of life extension and implementing the extended power uprate at Monticello, which are not directly related to the projects included in this ADP request, are contained in Section 2 of Attachment C

⁷ Externality values were not included in the economic analyses in conformity with N.D.C.C. § 49-02-23. However, the potential for future environmental regulations was considered qualitatively. This issue is discussed in more detail in Attachment C.

V. STANDARD OF REVIEW

North Dakota law provides that the Commission may issue an Order granting an Advance Determination of Prudence if “the [C]ommission determines that the resource addition is reasonable and prudent.” Specifically, North Dakota law provides:

49-05-16. Advance Determination of Prudence.

A public utility proposing to construct, lease, or make improvements to an energy conversion facility, renewable energy facility, transmission facility, or proposed energy purchase contract from another entity or person for the purpose of ensuring reliable electric service to its customers may file an application with the commission for advance determination of prudence regarding the proposal....

This standard is similar to the “honestly and prudently invested” standard that the Commission uses for ratemaking. N.D.C.C. § 49-06-02. The general prudence standard calls for determining whether the utility action was reasonable at the time it was taken under all relevant circumstances. *See* Charles F. Philips, Jr., *THE REGULATION OF PUBLIC UTILITIES – THEORY AND PRACTICE* at 292 (Public Utility Reports 1988); *see also* David. J. Muchow, William A. Mogel, *ENERGY LAW AND TRANSACTIONS* at § 4.02[3][b] (2009). Under N.D.C.C. § 49-05-16, the Commission may issue an order approving the prudence if three conditions are met:

- a. The public utility files with its application a projection of costs to the date of the anticipated commercial operation of the facility addition;
- b. The commission provides notice and holds a hearing, if appropriate, in accordance with section 49-02-02; and
- c. The commission determines that the facility is reasonable and prudent.⁸

The Commission’s standard for issuing an ADP is similar to the determination that is made in a rate case: the difference is the timing of the decision. Rather

⁸ N.D.C.C. § 49-05-16, subd. 1(b) also requires an application fee of one hundred twenty-five thousand dollars, which is being provided in connection with our Application.

than wait to consider the prudence of a particular investment in a rate case after construction, the ADP process considers prudence at the time of the decision to invest in the resource.

In this Application the Company provides estimates of costs for steam generator replacement and generation capacity increases at Prairie Island up to the date of commercial operation. We also provide our analysis of the cost of energy from our system with these improvements along with the rest of our nuclear management program compared to the alternatives, which demonstrates our steam generator replacement and generation capacity increases at Prairie Island as well as the nuclear investment plan is prudent and reasonable.

The two projects for which we are requesting an ADP are part of a much larger program of investments designed to prudently manage our nuclear assets for the benefit of our customers. The specific requests for an ADP in this Application are for two elements of our nuclear asset management program, which represent large capital investments that are prerequisites to capturing the benefits for our customer and have not yet been fully implemented. In our judgment they represent the elements of the nuclear investments that best lend themselves to an ADP proceeding.

It is our primary purpose, regardless of how the ADP request has been structured, to provide the Commission the opportunity to comprehensively review our plant life extension and capacity increase programs at both nuclear plants. If the Commission believes the way we have structured our ADP request in any way restricts review and discussion of our nuclear program, we are certainly willing to work with the Commission in such a manner as the Commission directs. We have not included testimony in support of this application with our initial filing, but can provide it if the Commission wishes.

VI. ASSESSMENT OF PRUDENCE AND REASONABLENESS

The assessments supporting the Prairie Island life extension and EPU are presented below. As discussed, the Prairie Island steam generator replacement is one component of the life extension project, but the collective project must be included in the economic analysis and assessment. Therefore, the assessment to the ADP requirements was performed based on the entire life

extension project, which includes all components and their respective costs listed in Attachment B.

A. Continued Operation of Prairie Island Provides Significant Economic Benefits

Xcel Energy has conducted extensive analysis to evaluate the impact of continuing to operate Prairie Island. If Prairie Island is closed at the end of its original licensed life, its output would have to be replaced. Our analysis indicates that Prairie Island is the least cost resource each time we have conducted such comparisons. We can save customers hundreds of millions of dollars over the next two to three decades by continuing to operate Prairie Island.

1. System Performance Analysis using the Strategist Model

To evaluate and compare the economic costs and benefits of our nuclear projects and alternatives, Xcel Energy utilizes the Strategist resource-planning model. Strategist models the load and generation resources for the entire NSP System in order to develop a long-range forecast of total system costs of proposed projects and alternatives, under a range of assumptions and sensitivities. This approach allows for an apples-to-apples comparison of alternatives.

Strategist calculates a “total system cost” for each proposed project, alternative and sensitivity, including fuel consumption, fuel costs, O&M costs, emission rates, capital costs and total revenue requirement. Each total system cost is reported as the net present value of revenue requirements or “PVRR.” This value is the sum of all operating, depreciation, return on rate base, and tax costs, less any revenues, discounted using a weighted after tax cost of capital of 7.42%.

The inputs used in Strategist represent the Company’s best estimate of future conditions. By their nature, forecasts are imprecise and can be the subject of reasonable disagreement. To mitigate forecast and assumption uncertainty, the Company employs sensitivity analyses to test the impacts of input assumptions. Each of the major inputs and how the Company employed them in the analysis are discussed next. Section 1 of Attachment C contains an overview of the strategist model and its major assumptions.

In conformity with N.D.C.C. § 49-02-23, environmental externality values have been removed from our analyses performed for this ADP Application. We included two coal replacement alternatives to the continued operating of Prairie Island; one with carbon sequestration and one without. The inclusion of the capital costs for emission reduction measures for comparative purposes without the quantification of externalities is consistent with N.D.C.C. § 49-02-23.

2. *Prairie Island Life Extension Alternatives Analysis*

We selected three primary alternatives to extending operations at Prairie Island:

Coal Facility without Sequestration: The Prairie Island life extension project was compared to replacing Prairie Island’s energy and capacity with a 1260 MW super critical pulverized coal plant with no carbon sequestration;

Coal Facility with Partial Sequestration: The Prairie Island life extension project was compared to replacing Prairie Island’s energy and capacity with a 1260 MW super critical pulverized coal plant with 50% carbon sequestration; and

Natural Gas Facility: The Prairie Island life extension project was compared to replacing Prairie Island’s energy and capacity with two natural gas combined cycle units with a total capacity of 1,254 MW.

While all of these alternatives would provide our system with the needed capacity and energy that are currently provided by Prairie Island, all are more expensive alternatives than continued operation of Prairie Island.

Table 4: Prairie Island Life Extension vs. Alternatives – Base Case Analysis

Present Value of Revenue Requirements (PVRR) Base Case Assumptions		
	PVRR (\$ millions)	Difference (\$ millions)
Prairie Island Life Extension	\$55,526	
Super Critical Pulverized Coal without Sequestration	\$55,840	+ \$314
Super Critical Pulverized Coal with 50% Sequestration	\$56,557	+ \$1,031
Natural Gas Combined Cycle	\$55,999	+ \$473

As set out in Table 4 above, the life extension alternative is over \$300 million dollars more economical than the next best alternative, a SCPC coal generation facility with no carbon sequestration.

To test the robustness of our assumptions, we also performed numerous sensitivity analyses. As shown in Table 5 below, the finding that the Prairie Island life extension project is the least cost alternative holds true across a broad range of sensitivities. In only one sensitivity case, i.e., the natural gas combined cycle scenario with a 20 percent decrease in the long-term projection of the price of natural gas, does an alternative have a lower PVRR than extending the life of Prairie Island.

Table 5: Prairie Island Life Extension vs. Alternatives –Sensitivity Analysis

PVRR Sensitivities (\$ Millions)				
	Prairie Island Life Extension	SCP Coal w/ No CO ₂ Seq	SCP Coal w/ 50% CO ₂ Seq	Natural Gas Combined Cycle
	PVRR	PVRR Difference		
Base Case	\$55,526	\$314	\$1,031	\$473
Low Load	\$53,220	\$232	\$922	\$335
High Load	\$58,085	\$330	\$1,061	\$604
Coal + 20	\$56,611	\$499	\$1,223	\$544
Gas + 20	\$57,769	\$552	\$1,334	\$1,103
Nuke + 20	\$55,937	\$137	\$854	\$296
Coal – 20	\$54,449	\$129	\$841	\$403
Gas – 20	\$54,449	\$59	\$709	(\$182)
Nuke – 20	\$55,115	\$490	\$1,207	\$649
MISO On	\$55,034	\$447	\$1,200	\$727
Capital Cost Escalation 3%	\$56,971	\$255	\$980	\$381
Capital Cost Escalation 5%	\$59,499	\$78	\$790	\$277

Table 6 provides the estimated levelized system and customer impacts for the Prairie Island life extension project. The monthly residential customer impact, calculated assuming 850 kilowatt-hours per month usage will result in over

\$36.00 in savings per year per customer for the additional 20 years of plant operation.

Table 6: Prairie Island Life Extension

	\$/MWH	Monthly Rate Impact Assuming 850 kWh/month
Prairie Island Life Extension	\$70.25	\$10.99
SCPC without Sequestration (Next Best Alternative)	\$89.48.	\$14.00
Difference	\$19.23	\$3.01

3. Prairie Island Extended Power Uprate Alternatives Analysis

We selected three primary alternatives to compare to the Prairie Island extended power uprate project:

164 MW Coal PPA: The Prairie Island EPU was compared to a generic PPA purchase of 164 MW of capacity and associated energy from a generation facility that uses coal as its primary fuel source. The hypothetical coal PPA price was modeled to have the same cost, performance and emission characteristics of a new conventional coal facility.

164 MW Biomass Facility: The Prairie Island EPU was compared to a new 164 MW biomass generation facility. The hypothetical biomass facility was modeled to have the similar capital costs to other base load steam plants, with fuel costs and operating characteristics based on our existing plants and fuel forecasts.

Unconstrained Scenario -- Natural Gas Combustion Turbine: To select the third alternative, we allowed Strategist to select the most cost-effective combination of resources from the resources made available to the model, including coal, natural gas combined cycle and natural gas combustion turbine. In this “unconstrained” analysis, Strategist selected a generic natural gas combustion turbine to fill the capacity need, and energy needs were filled using new and existing energy resources.

As can be seen from the summary table below (Table 7), the Prairie Island EPU project is the most cost-effective resource for this capacity and associated energy, with a PVRR of \$185 million less than the closest alternative – the coal PPA.

Table 7: Prairie Island Extended Power Uprate vs. Alternatives –Base Case Analysis

Present Value of Revenue Requirements (PVRR) Base Case Assumptions		
(\$ millions)	PVRR	Difference
Prairie Island Extended Power Uprate Project	\$55,240	
Coal PPA 164 MW	\$55,425	+\$185
Biomass Facility 164 MW	\$55,714	+\$473
Unconstrained (Natural Gas CT)	\$55,526	+\$285

Further, this finding holds across all sensitivities performed (see Table 8). Under each and every alternative and sensitivity tested, the Prairie Island EPU project is the most cost effective alternative.

Table 8: Prairie Island Extended Power Uprate vs. Alternatives – Sensitivity Analysis

	Extended Power Uprate Project	Coal PPA 164 MW	Biomass facility 164 MW	Unconstrained Natural Gas CT
	PVRR	PVRR Difference from PI Uprate Project		
Base Case	\$55,240	\$185	\$473	\$285
Low Load	\$52,847	\$307	\$619	\$373
High Load	\$57,852	\$43	\$364	\$233
Coal + 20	\$56,312	\$226	\$473	\$299
Gas + 20	\$57,392	\$167	\$472	\$377
Nuke + 20	\$55,666	\$170	\$458	\$271
Coal – 20	\$54,178	\$143	\$474	\$272
Gas – 20	\$54,178	\$211	\$474	\$192
Nuke – 20	\$54,815	\$200	\$488	\$300
MISO On	\$54,687	\$155	\$471	\$346

	Extended Power Uprate Project	Coal PPA 164 MW	Biomass facility 164 MW	Unconstrained Natural Gas CT
	PVRR	PVRR Difference from PI Uprate Project		
Capital Cost Escalation 3%	\$56,698	\$180	\$485	\$273
Capital Cost Escalation 5%	\$59,230	\$191	\$490	\$269

While the capital costs to implement the EPU at Prairie Island are significant, the overall cost to customers is less when compared to the “next best alternative”, i.e., the coal PPA. This is due to the significantly lower fuel and O&M costs. Table 9 provides the estimated levelized system and customer impacts for the Prairie Island EPU Project. The monthly residential customer impact is calculated assuming 850 kilowatt-hours per month usage. Implementing the EPU will result in approximately \$3.60 in savings per year versus the next best alternative, which was the hypothetical Coal PPA.

Table 9: Prairie Island Extended Power Uprate

	\$/MWH	Monthly Rate Impact Assuming 850 kWh/month
Prairie Island Extended Power Uprate	\$39.48	\$.79
Coal PPA “Next Best Alternative”	\$54.68	\$1.10
Difference	\$15.20	\$0.30

B. Continued Operation and Increased Capacity at Prairie Island Provides Environmental Benefits

1. Existing Infrastructure Benefits

Prairie Island is an existing facility, and the continued and increased operation of the plant will take full advantage of existing plant infrastructure. The plant and ISFSI footprints will not be expanded, and no greenfields will be affected by the projects. Although the additional dry cask storage involves the

construction of two concrete storage pads within the ISFSI, we will not need to construct or modify any building footprint, access roads, parking areas, or lay down areas to support the additional dry cask storage for the life extension project and the modification necessary to implement the extended power uprate will be confined to the existing plant footprint and largely to within the existing buildings.

2. Air Emission Benefits

Prairie Island is an existing generation source with negligible emissions. Replacing Prairie Island with a fossil fueled generation resource would significantly increase air emissions. Continued operation of Prairie Island as compared to the replacement alternatives prevents millions of tons of NO_x, SO₂, mercury, and particulates from being released over the next 20 years. Table 10 demonstrates the air emission benefits associated with continuing to operate Prairie Island an additional 20 years versus the alternatives and Table 11 demonstrates the environmental benefits of increasing the capacity of the plant via the extended power uprate versus the alternatives.

Table 10: Prairie Island Life Extension vs. Alternatives – Emissions Comparison

Emission	Prairie Island Life Extension	SCP Coal w/ No CO ₂ Seq	SCP Coal w/ 50% CO ₂ Seq	Natural Gas Combined Cycle
	Tons Emitted	Additional Tons of Emissions		
SO _x	413,962	67,201	72,624	51,025
NO _x	306,050	43,573	47,825	32,325
CO ₂	462,757,348	125,287,414	98,014,242	94,205,370
CO	76,866	59,978	59,859	12,043
PM ₁₀	51,022	10,714	11,342	7,607
VOC	12,064	2,080	2,234	1,524

Table 11: Prairie Island Uprate Project vs. Alternatives – Emissions Comparison

	Coal PPA – 164 MW	Biomass facility – 164 MW	Unconstrained – Natural Gas CT
	Additional Tons Emitted		
SO ₂	36,799	19,711	9,571
NO _x	22,062	99,454	6,738
CO ₂	29,415,864	61,526,018	14,475,312
CO	4,300	17,619	1,974
PM10	2,889	4,401	1,244
VOC	505	776	283

While the North Dakota externalities statute prohibits the use of externality values in planning resource deployment or ratemaking,⁹ the Commission has interpreted this statute to mean that it cannot consider environmental externality costs quantitatively, but that it can consider them qualitatively.¹⁰ When making this qualitative assessment, the Commission has considered, for example, the potential for future environmental regulation to affect fuel costs in the future, including natural gas costs.¹¹ We present the increases or decreases in emission amounts of the various alternatives from Strategist above for qualitative consideration: None of the PVRR analyses discussed above (or those included in Section 2 of Attachment C regarding Monticello’s life extension or EPU projects) included the monetization of environmental externalities.

⁹ N.D.C.C. § 49-02-23.

¹⁰ See *Otter Tail Corporation Advance Determination of Prudence Application*, Findings of Fact, Conclusions of Law, and Order, Case No. PU-06-481 at ¶¶ 36-9 (N.D. P.S.C. August 27, 2008) (“Big Stone ADP Order”).

¹¹ *Id.*

Considerable discussion and public policy debate is occurring around the possibility of regulations to address the issue of global climate change and the impact of green house gas emissions. If carbon regulation occurs at sometime in the next two or three decades, the cost of the fossil fueled alternatives to Monticello and Prairie Island would be more expensive than the results presented herein. Nuclear power maintains system diversity and represents a significant risk mitigator of added cost associated with possible future emission regulations.

VII. CONCLUSION

As presented in this ADP Application, the Company's proposal for life extension and capacity increases at each of the Prairie Island and Monticello nuclear plants are complex, multi-component and inter-related projects that when implemented, will provide significant benefits to customers. A comprehensive analysis of our nuclear investment strategy is necessary to fairly and accurately determine the economics of the nuclear investments. The life extension and EPU projects are all at a different stages of implementation. Since the life extension and EPU projects at Monticello are further along in the approval and implementations stages, and were well underway prior to our commitment to file an ADP, we have not included them in this Application.¹² Therefore, we are only seeking ADP determinations for: (1) the Unit 2 steam generator replacement at Prairie Island; and (2) the Prairie Island EPU.

The Prairie Island life extension and extended power uprate projects meet the standard for the Commission to make an advance determination of prudence and reasonableness.

Numerous analyses confirm that the projects are the most cost-effective option to provide reliable electric generation in order to meet our customers' needs and will also provide a hedge against future fuel price increases and the possibility of future environmental regulations. The continued use and expansion of Prairie Island will occur within the existing plant and ISFSI footprints, thereby utilizing the existing generation sites and electric transmission infrastructure.

¹² The Company will seek recovery of costs related to Monticello as a part of a future rate case.

Therefore, we respectfully request the Commission make a determination that the life extension and EPU projects at Prairie Island meet the Advance Determination of Prudence requirements under N.D.C.C. § 49-05-16.

VIII. COMMUNICATION AND SERVICE LIST

We respectfully request that the following persons be placed on the Commission's official service list for all official communications in this case:

Brian R. Zelenak
Manager Regulatory Administration
Xcel Energy Services Inc.
414 Nicollet Mall, 7th Floor
Minneapolis, MN 55401

SaGonna Thompson
Records Specialist
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David Sederquist
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Xcel Energy Services Inc.
2302 Great Northern Drive Fargo, ND
58102

Dated: April 19, 2010

Northern States Power Company,
a Minnesota Corporation

RESPECTFULLY SUBMITTED,

/s/

BRIAN R. ZELENAK
MANAGER, REGULATORY ADMINISTRATION

ATTACHMENT A

Project	Filed	Agency	Approval Status
Prairie Island Life Extension & Dry Cask Storage			
TN40 Transportation License	Filed: August, 2006	NRC	Anticipated: Mid 2010
TN40-HT Storage License	Filed: March 28, 2008	NRC	Anticipated: March 1, 2010
Plant Relicensing/Operating Extension	Filed: April 15, 2008	NRC	Anticipated: October 31, 2010
Certificate of Need for Additional Spent Fuel Storage Capacity	Filed: May 16, 2008	MN-PUC	Approved: December 18, 2009
Report to Legislature for additional casks	Filed: January 15, 2010	State Legislature	Legislative Stay Ends: June 1, 2010
TN40-HT Transport License	Anticipated: 2010	NRC	Anticipated: 2011
ISFSI License Renewal	Anticipated: September 29, 2011	NRC	Anticipated: October 30, 2013
License to Increase the Number of Casks at ISFSI	Anticipated: December 15, 2018	NRC	Anticipated: September 30, 2019
Prairie Island Extended Power Uprate			
Larger Diameter Fuel	Filed: April 15, 2008	NRC	Approved: July 1, 2009
EPU Certificate of Need Application	Filed: May 16, 2008	MN-PUC	Approved: December 18, 2009
Site Permit Application	Filed: August 1, 2008	MN-PUC	Approved: December 18, 2009; Decision Issued: December 21, 2009
EPU License Amendment	Anticipated: October 31, 2010	NRC	Anticipated: 4th Qtr. 2013
Monticello Life Extension & Dry Cask Storage			
Certificate of Need for Additional Spent Fuel Storage Capacity	Filed: January 18, 2005	MN-PUC	Approved: October 23, 2006
Plant Relicensing/Operating Extension	Filed: March 24, 2005	NRC	Approved: November 2006
Report to Legislature for additional casks Minn. Stat. Section 116 ended 6-2-08	Filed: October 23, 2006	State Legislature	Approved: June 2, 2008
Monticello Extended Power Uprate			
EPU Certificate of Need Application	Filed: February 14, 2008	MN-PUC	Approved: January 8, 2009
EPU Site Permit Application	Filed May 2, 2008	MN-PUC	Approved: December 23, 2008
EPU License Amendment	Filed: November 5, 2008	NRC	Final Approval Anticipated: Late 2010

**Attachment B
Projection of Costs
N.D.C.C. § 49-05- 16(i)(a)**

ADP Application
Nuclear Projects
PU-10-____
April 19, 2010

Estimated Nuclear Project Costs By Year		(In Millions of Dollars)																												Total				
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034		
Corporate Escalation Rate >>>		2.54%	2.37%	2.15%	2.10%	2.20%	2.31%	2.40%	2.59%	2.72%	2.78%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%			
Prairie Island Life Extension																																		
PI Dry Storage (Casks 30 through 64) (2008\$)	2007 \$'s	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 4.0	\$ 6.9	\$ 9.6	\$ 6.7	\$ 3.9	\$ 6.1	\$ 7.4	\$ 7.0	\$ 6.1	\$ 7.3	\$ 6.1	\$ 5.4	\$ 7.2	\$ 6.8	\$ 6.2	\$ 7.4	\$ 7.0	\$ 6.2	\$ 7.4	\$ 5.1	\$ 4.1	\$ 4.0	\$ 3.1	\$ 1.6	\$ 1.6	\$ 3.3	\$ 147.5	
PI Dry Storage (1)	escalated \$'s	\$ -	\$ -	\$ 4.0	\$ 7.1	\$ 10.1	\$ 7.2	\$ 4.3	\$ 6.9	\$ 8.6	\$ 8.4	\$ 7.5	\$ 9.2	\$ 7.8	\$ 7.1	\$ 9.7	\$ 9.4	\$ 8.8	\$ 10.8	\$ 10.4	\$ 9.5	\$ 11.6	\$ 8.2	\$ 6.8	\$ 6.8	\$ 5.4	\$ 2.8	\$ 2.9	\$ 6.1	\$ 197.4				
Life Cycle Management	2007 \$'s	\$ -	\$ -	\$ -	\$ -	\$ 4.3	\$ 8.1	\$ 21.1	\$ 34.2	\$ 40.6	\$ 29.0	\$ 12.4	\$ 29.3	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Life Cycle Management Escalated	escalated \$'s	\$ -	\$ 4.4	\$ 8.4	\$ 22.6	\$ 37.6	\$ 45.8	\$ 33.6	\$ 14.8	\$ 35.7	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -			
Unit 2 Steam Generator Replacement	2007 \$'s	\$ -	\$ -	\$ -	\$ 4.3	\$ 4.8	\$ 6.1	\$ 22.6	\$ 34.7	\$ 36.1	\$ 149.7	\$ 0.6	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Operating License Renewal	2007 \$'s	\$ -	\$ -	\$ -	\$ 6.7	\$ 7.0	\$ 4.9	\$ 1.2	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Operating License Renewal	escalated \$'s	\$ -	\$ -	\$ -	\$ 6.7	\$ 7.2	\$ 5.1	\$ 1.3	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Routine Capital Projects	2007 \$'s	\$ -	\$ -	\$ -	\$ 20.3	\$ 23.3	\$ 23.6	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 20.0	\$ 10.0	\$ 10.0	\$ 5.0	\$ 5.0	\$ 5.0	\$ 5.0		
Routine Capital Projects	escalated \$'s	\$ -	\$ -	\$ -	\$ 20.3	\$ 23.8	\$ 24.7	\$ 21.4	\$ 22.0	\$ 22.6	\$ 23.2	\$ 23.8	\$ 24.4	\$ 25.0	\$ 25.6	\$ 26.2	\$ 26.9	\$ 27.6	\$ 28.3	\$ 29.0	\$ 29.7	\$ 30.4	\$ 31.2	\$ 32.0	\$ 32.8	\$ 33.6	\$ 17.2	\$ 17.6	\$ 9.0	\$ 9.3	\$ 9.5	\$ 9.7		
Prairie Island Life Extension Subtotal	escalated \$'s	\$ -	\$ -	\$ -	\$ 31.3	\$ 40.2	\$ 48.3	\$ 75.0	\$ 104.3	\$ 111.7	\$ 210.8	\$ 46.1	\$ 68.7	\$ 33.3	\$ 33.1	\$ 35.4	\$ 34.7	\$ 34.7	\$ 38.0	\$ 38.4	\$ 38.5	\$ 41.2	\$ 41.6	\$ 41.5	\$ 44.4	\$ 41.8	\$ 24.0	\$ 24.4	\$ 14.4	\$ 12.1	\$ 12.4	\$ 15.9	\$ 1,336.1	
Prairie Island Extended Power Uprate																																		
Extended Power Uprate	2007 \$'s	\$ -	\$ -	\$ -	\$ 9.5	\$ 6.0	\$ 28.2	\$ 47.4	\$ 47.9	\$ 56.9	\$ 35.8	\$ 14.0	\$ 49.1	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Extended Power Uprate	escalated \$'s	\$ -	\$ -	\$ -	\$ 9.5	\$ 6.1	\$ 29.5	\$ 50.8	\$ 52.6	\$ 64.2	\$ 41.5	\$ 16.7	\$ 59.8	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Prairie Island EPU Subtotal	escalated \$'s	\$ -	\$ -	\$ -	\$ 9.5	\$ 6.1	\$ 29.5	\$ 50.8	\$ 52.6	\$ 64.2	\$ 41.5	\$ 16.7	\$ 59.8	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -			
Prairie Island Total	escalated	\$ -	\$ -	\$ -	\$ 40.8	\$ 46.3	\$ 77.8	\$ 125.7	\$ 156.9	\$ 175.9	\$ 252.4	\$ 62.8	\$ 128.5	\$ 33.3	\$ 33.1	\$ 35.4	\$ 34.7	\$ 34.7	\$ 38.0	\$ 38.4	\$ 38.5	\$ 41.2	\$ 41.6	\$ 41.5	\$ 44.4	\$ 41.8	\$ 24.0	\$ 24.4	\$ 14.4	\$ 12.1	\$ 12.4	\$ 15.9	\$ 1,666.8	
Monticello Life Extension																																		
ISFSI Construction and Casks (3)	2007 \$'s	\$ 1.7	\$ 3.1	\$ 10.1	\$ 13.0	\$ 11.9	\$ 0.4	\$ 2.0	\$ 6.7	\$ 7.1	\$ 11.8	\$ 4.1	\$ 9.3	\$ 8.0	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Monticello ISFSI and Casks (3)	escalated \$'s	\$ 1.7	\$ 3.1	\$ 10.1	\$ 13.0	\$ 11.9	\$ 0.4	\$ 2.0	\$ 7.0	\$ 7.7	\$ 13.1	\$ 4.7	\$ 10.8	\$ 9.6	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Operating License Renewal (4)	2007 \$'s	\$ -	\$ -	\$ -	\$ 26.3	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Operating License Renewal	escalated \$'s	\$ -	\$ -	\$ -	\$ 26.3	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Routine Capital Projects	2007 \$'s	\$ 7.3	\$ 9.0	\$ 6.6	\$ 7.0	\$ 9.8	\$ 9.6	\$ 9.8	\$ 9.5	\$ 10.0	\$ 9.7	\$ 10.0	\$ 9.7	\$ 10.0	\$ 10.0	\$ 10.0	\$ 10.0	\$ 10.0	\$ 10.0	\$ 10.0	\$ 10.0	\$ 10.0	\$ 10.0	\$ 10.0	\$ 5.0	\$ 5.0	\$ 5.0	\$ 5.0	\$ 2.5	\$ 2.5	\$ -	\$ -	\$ -	\$ -
Routine Capital Projects	escalated \$'s	\$ 7.3	\$ 9.0	\$ 6.6	\$ 7.0	\$ 10.0	\$ 10.0	\$ 10.5	\$ 10.0	\$ 10.8	\$ 10.8	\$ 11.4	\$ 11.3	\$ 12.5	\$ 12.8	\$ 13.1	\$ 13.4	\$ 13.8	\$ 14.1	\$ 14.5	\$ 14.8	\$ 15.2	\$ 7.8	\$ 8.0	\$ 8.2	\$ 8.4	\$ 4.3	\$ 4.4	\$ -	\$ -	\$ -	\$ -	\$ -	
Monticello Life Extension Subtotal	escalated \$'s	\$ 9.0	\$ 12.1	\$ 16.7	\$ 46.3	\$ 21.9	\$ 10.4	\$ 12.5	\$ 17.0	\$ 18.5	\$ 23.8	\$ 16.0	\$ 22.1	\$ 22.0	\$ 12.8	\$ 13.1	\$ 13.4	\$ 13.8	\$ 14.1	\$ 14.5	\$ 14.8	\$ 15.2	\$ 7.8	\$ 8.0	\$ 8.2	\$ 8.4	\$ 4.3	\$ 4.4	\$ -	\$ -	\$ -	\$ -	\$ 401.4	
Monticello Extended Power Uprate																																		
Extended Power Uprate	2007 \$'s	\$ 0.9	\$ -	\$ 6.2	\$ 11.8	\$ 23.6	\$ 26.3	\$ 30.1	\$ 19.3	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Extended Power Uprate	escalated	\$ 0.9	\$ -	\$ 6.5	\$ 13.4	\$ 25.7	\$ 28.6	\$ 32.6	\$ 22.6	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Monticello Extended Power Uprate Subtotal	escalated	\$ 0.9	\$ -	\$ 6.5	\$ 13.4	\$ 25.7	\$ 28.6	\$ 32.6	\$ 22.6	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Monticello Total		\$ 9.9	\$ 12.1	\$ 23.2	\$ 59.7	\$ 47.6	\$ 39.0	\$ 45.1	\$ 39.7	\$ 18.5	\$ 23.8	\$ 16.0	\$ 22.1	\$ 22.0	\$ 12.8	\$ 13.1	\$ 13.4	\$ 13.8	\$ 14.1	\$ 14.5	\$ 14.8	\$ 15.2	\$ 7.8	\$ 8.0	\$ 8.2	\$ 8.4	\$ 4.3	\$ 4.4	\$ -	\$ -	\$ -	\$ -	\$ 531.7	
Estimated Total Nuclear Projects		\$ 9.9	\$ 12.1	\$ 23.2	\$ 100.4	\$ 93.9	\$ 116.8	\$ 170.8	\$ 196.6	\$ 194.4	\$ 276.2	\$ 78.8	\$ 150.7	\$ 55.4	\$ 45.9	\$ 48.5	\$ 48.2	\$ 48.5	\$ 52.1	\$ 52.9	\$ 53.3	\$ 56.4	\$ 49.4	\$ 49.4	\$ 52.6	\$ 50.2	\$ 28.3	\$ 28.8	\$ 14.4	\$ 12.1	\$ 12.4	\$ 15.9	\$ 2,198.5	
(1) Escalated in 2010 and beyond																																		
(2) Life Cycle Management (LCM) Costs for EPU are included in Life Extension also. These costs are assigned to the EPU project and the LCM are reduced by same amount in the EPU analysis.																																		
(3) Costs Included are Actual Costs Incurred through 2009. Future costs are estimates for cask loading campaigns in 2013 and 2016.																																		
(4) 2007 Actual Dollars Spent																																		

ATTACHMENT C

Section 1: Strategist Overview

To evaluate and compare the economic costs and benefits of our proposed projects and alternatives, Xcel Energy utilizes the Strategist resource-planning model. Xcel Energy uses Strategist to model the load and generation resources for the entire NSP System in order to develop a long-range forecast of total system costs of proposed projects and alternatives, under a range of assumptions and sensitivities. This approach allows for an apples-to-apples comparison of alternatives.

The Strategist model consists of four primary components:

Load Module: This module contains the NSP System load forecast, load management resources, and conservation programs. It produces long-range estimates of the NSP System's hourly load, net energy requirements, and annual peak load.

Generation Module: This module contains the operating costs and performance characteristics for our thermal units, renewable resources, and energy transactions. It uses an hourly dispatch simulation to estimate how customer demand will be met and what the associated costs and emissions will be.

Capital Project Module: This module estimates the revenue requirements for capital projects. It keeps track of rate base, depreciation, taxes, and rate of return.

Expansion Planning Module (Proview TM): This module uses a dynamic programming algorithm to derive the least-cost combination of possible new generation resources. It calculates the ratepayer and societal costs for thousands of different resource combinations to arrive at a least-cost plan.

As noted above, Strategist calculates a "total system cost" for each proposed project, alternative and sensitivity, including fuel consumption, fuel costs, O&M costs, emission rates, capital costs and total revenue requirement. Each total

system cost is reported as the net present value of revenue requirements or “PVERR.” This value is the sum of all operating, depreciation, return on rate base, and tax costs, less any revenues, discounted using a weighted after tax cost of capital of 7.42%.

a. Strategist Input Assumptions

The inputs used in Strategist represent the Company’s best estimate of future conditions at the time of the filing(s). By their nature, forecasts are imprecise and can be the subject of reasonable disagreement. To mitigate forecast and assumption uncertainty, the Company employs sensitivity analyses to test the impacts of input assumptions. Each of the major inputs and how the Company employed them in the analysis are discussed next.

The analyses and underlying assumptions of those analyses contained in this filing are consistent with the filings made with the Minnesota Public Utilities Commission regarding the projects. The Strategist model was updated with demand and energy forecasts, fuel forecasts, cost estimates and corporate assumptions as discussed below for the 2008 Resource Plan (“Resource Plan”) (Docket No. E002/RP-07-1572) that was filed in December 2007.¹ The Strategist model containing the same underlying assumptions was also then used for the analysis supporting the Monticello Extended Power Uprate Certificate of Need Application in February 2008 (Docket No. E002/CN-08-185) and the Prairie Island Additional Dry Casks Storage/Life Extension and Extended Power Uprate Certificates of Need Applications filed in May 2008 (Docket Nos. E002/CN-08-510 and E002/CN-08-509 respectively).

In September 2008, the Company filed Reply Comments in our Resource Plan filing in Minnesota that laid out a summary of actions the Company had taken to implement our five-year Action Plan contained in the Resource Plan and also provided an update regarding a number of major assumptions (modeling) that had been made since the initial filing. These assumption changes were necessary to reflect the changing economic and regulatory conditions, including the Office

¹ Monticello Life Extension analysis for Docket E002/CN-05-123 was conducted in 2004/2005 and uses Strategist assumptions consistent with the 2004 Resource Plan, not the 2007 Resource Plan.

of Energy Security's comments on our Strategist assumptions used in the Resource Plan. (A copy of the Company's Reply Comments is contained in Schedule 1. Schedule 1 outlines the major assumption changes made in Strategist.)

In November of 2008, the Company filed an electric rate increase in Minnesota. A newer, slightly lower demand and energy forecast was available and used in the rate case filing. In March of 2009, the Company filed a Supplement in the Prairie Island Additional Dry Cask Storage and Extended Power Uprate dockets in Minnesota. The supplement contained an updated analysis of the two projects utilizing the forecast from the rate case and containing the updated assumptions discussed in the Resource Plan Reply Comments and discussed in Schedule 1.

For consistency between jurisdictions and their respective regulatory bodies, the analyses contained in this filing are consistent with the analyses submitted in the respective filings discussed above – with two exceptions. Per NDCC § 49-02-23, the externality values have been removed for this ADP. Additionally, the Prairie Island Life Extension analysis included a coal alternative with 50% carbon sequestration. For this ADP filing, we also included a coal analysis without carbon sequestration. Below is a brief description of the major assumption areas in Strategist.²

(1) Generation Resources

In Strategist, the Company models all the generation resources in the NSP System. The operating characteristics are based on historical data and modified to reflect any planned changes to the units.

Inputs for each unit include: maximum dependable capacity, firm capacity (URGE), heat rate profiles, emission profiles, maintenance schedules, forced outage rates, fuel cost, variable O&M, and fixed O&M.

² Examples primarily relate to the analyses performed for the Prairie Island Life Extension and the Monticello and Prairie Island Extended Power Uprates.

(2) Load Forecast

The load forecast used in the Company's analysis is based on historical data but also integrates the expected impact of the recent economic contraction on consumer demand. Both a low load growth and a high load growth scenario were used to test the sensitivity of the model results to the load forecast.

The base forecast (unadjusted for DSM) has an average energy growth rate of 1.14 percent. The energy growth rate was adjusted down to average 1 percent and was also adjusted up to average 1.3 percent.

As with previous resource plan modeling, the median or 50 percent probability forecast for energy (50 percent of the time the forecast would be over, and 50 percent of the time the forecast would be under, the 50/50 forecast), and the 90 percent probability for peak demand were used. The 90 percent probability forecast of peak demand was used to ensure that we have sufficient generation capacity to meet energy demand under most plausible circumstances.

(3) Fuel Cost Forecasts

The Company uses a variety of resources to develop our long-range fuel cost forecast, including both publicly available data and competitively sensitive information not available to the public. The cost of natural gas, coal, and nuclear fuel were all independently adjusted up and down by 20 percent, to test the sensitivity of the analysis to these factors.

(4) Other Input Assumptions

We modeled the various alternatives under different assumptions regarding fuel, environmental and capital costs. The resulting total system costs and emission levels were compared to evaluate the alternatives for cost-effectiveness and environmental impacts.

In order to determine how changes in our assumptions impact the costs or characteristics of proposed projects and alternatives, we examine these under a number of sensitivities. For these modeling runs, we tested a number of sensitivities, including:

- MISO – The Company’s resource planning philosophy is to plan for future needs as if the NSP System were a stand-alone system. This approach ensures that the Company will meet the needs of our customers regardless of developments elsewhere in the market. Since the launch of the MISO energy market, the operation and costs of the NSP System have been intertwined with all of the NSP System’s neighboring utilities. To model a stand-alone NSP system, all interactions in Strategist with the MISO market were turned off, and only NSP units and firm bilateral transactions were used to meet customer demand. As a further sensitivity, market interactions were turned on and the model was allowed to purchase energy from or sell excess energy to the market.
- Capital Cost Escalation – The base assumption in Strategist is that the cost of capital projects will increase at 1.88 percent. 3 percent and 5 percent cost escalation scenarios were also run to evaluate expansion plan sensitivity to escalation assumptions.

(5) Screening and Selection of Alternatives

The process for selecting and evaluating alternatives for each proposed project is a multi-step process. First, we performed a qualitative screening of a wide range of approaches and technologies to identify alternatives that have similar energy and capacity characteristics to the proposed project. Alternatives that were not reasonably applicable to the need or that were deemed to be excessively risky or costly were screened out from further consideration. From the qualitative screening, we selected options to model in Strategist for a more thorough quantitative assessment and compare them against the relevant proposed project.

In conformity with N.D.C.C. § 49-02-23, environmental externality values have been removed from all analyses contained in this application: the Prairie Island Life Extension; the Prairie Island Extended Power Uprate; the Monticello Life Extension; and the Monticello Extended power Uprate.

Section 2: Monticello Economic Assessment

A. Monticello Life Extension – Alternatives Analysis^{3,4}

Three alternatives were used to compare to the Monticello life extension project:

540 MW Coal Plant: The Monticello life extension project was compared to a 540 MW Super Critical Pulverized Coal (SCPC Coal) plant without carbon sequestration.

Two 270 MW Natural Gas Combined Cycle Plants: The Monticello life extension project was compared to adding two 270 MW natural gas combined cycle plants in 2010. Capital operating costs were based on the same data used to develop the proxy intermediate resources.

Wind and Natural Gas Combined Cycle plants: The Monticello life extension project was compared to adding the two 270 MW natural gas combined cycle plants and 240 MW of nameplate capacity wind generation.

While these alternatives would provide our system with the needed capacity and energy currently provided by Monticello life extension, all three alternatives were considerably more expensive as Table C-1 indicates.

³ The analysis for the life extension project at Monticello was performed in 2004 to support the Certificate of Need filing with the Minnesota Public Utilities Commission (*Supplement to Application to the Minnesota Public Utilities Commission for a Certificate of Need to Establish an Independent Spent Fuel Storage Installation at Monticello Generating Plant*, Docket No. E002/CN-05-123, June 5, 2005). Since that filing significantly predates our commitment to provide the Commission with ADP's, and was discussed in our last rate case (Case No. PU-07-776), the analysis is outdated in relation to the other three economic analyses presented in this Application. The base analysis performed for the Certificate of Need filing did not include externality values and thus the results presented represent the most recent analysis performed and what our decision to pursue life extension for Monticello was based upon without environmental externalities.

⁴ The analysis was performed prior to the adoption of renewable energy standards and goals and based on the assumption wind would not exceed 15% penetration.

**Table C-1: Monticello Life Extension vs. Alternatives –
 Base Case Analysis**

Present Value of Revenue Requirements (PVRR) Base Case Assumptions	
(\$ millions)	Difference
Monticello Life Extension Project	
SCPC Coal 540 MW	+ \$395
Natural Gas Combined Cycle 540 MW	+ \$560
Natural Gas Combined Cycle 540 MW and 240 MW Nameplate Wind	+ \$610

B. Monticello Extended Power Uprate – Alternatives Analysis

Three alternatives were used to compare to the Monticello EPU project:

71 MW Coal PPA: The Monticello EPU was compared to a generic power purchase of 71 MW of capacity and associated energy from a generation facility that uses coal as its primary fuel source. The hypothetical coal PPA price was modeled to have the same cost, performance and emission characteristics of a new conventional coal facility.

71 MW Biomass Facility: The Monticello EPU was compared to a new 71 MW biomass generation facility. The hypothetical biomass facility was modeled to have the similar capital costs to other base load steam plants, with fuel costs and operating characteristics based on our existing plants and fuel forecasts.

Unconstrained Scenario -- Natural Gas Combustion Turbine: To select the third alternative, we allowed Strategist to select the most cost-effective combination of resources from the resources made available to the model, including coal, natural gas combined cycle and natural gas combustion turbine. In this “unconstrained” analysis, Strategist selected a generic natural gas combustion turbine to fill the capacity need, and energy needs were filled using new and existing energy resources.

While these alternatives would provide our system with the needed capacity and energy that would be provided by the Monticello EPU project, all three alternatives were more expensive than the project. As Table C-2 indicates, the hypothetical coal PPA and the natural gas combustion turbine chosen in the unconstrained scenario are very similar in costs, with both PVRR's at about \$75 million. However, both cost more than implementing the Monticello EPU.

**Table C-2: Monticello Extended Power Uprate vs. Alternatives –
 Base Case Analysis**

Present Value of Revenue Requirements (PVRR) Base Case Assumptions		
(\$ millions)	PVRR	Difference
Monticello Extended Power Uprate Project	\$55,240	
Coal PPA 71 MW	\$55,315	+ \$74
Biomass Facility 71 MW	\$55,404	+ \$163
Natural Gas Combustion Turbine	\$55,316	+ \$75



414 Nicollet Mall
Minneapolis, Minnesota 55401

September 5, 2008

- VIA ELECTRONIC FILING -

Burl W. Haar
Executive Secretary
Public Utilities Commission
121 East Seventh Place, Suite 350
St. Paul, MN 55101-2147

RE: RESOURCE PLAN REPLY COMMENTS
DOCKET NO. E002/RP-07-1572

Dear Dr. Haar:

Northern States Power, a Minnesota corporation, is pleased to submit this Reply to Comments filed by Parties in our 2007 Resource Plan proceeding. We appreciated the participation of many, varied Parties to this proceeding and welcome this opportunity to reply.

In this Reply, we respond to issues raised by the Parties and present an updated analysis to reflect changes that occurred since we filing our Application on December 14, 2007.

Please contact either me at (612) 330-6732 or Betsy Engelking, Manager, Resource Planning and Bidding at (612) 330-7987 if you have any questions regarding this filing.

Sincerely,

JAMES ALDERS
DIRECTOR, REGULATORY ADMINISTRATION

Enclosures
c: Service List

**STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION**

Dr. David Boyd	Chair
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
Phyllis Reha	Commissioner
Betsy L. Wergin	Commissioner

IN THE MATTER OF AN APPLICATION
BY NORTHERN STATES POWER
COMPANY, A MINNESOTA
CORPORATION, FOR RESOURCE PLAN
APPROVAL 2008-2022

DOCKET NO. E-002/RP-07-1572

REPLY COMMENTS

INTRODUCTION

Northern States Power Company, a Minnesota corporation (“Xcel Energy” or the “Company”) offers this reply to comments submitted regarding our 2008 – 2022 Resource Plan. On June 16, 2008, several parties submitted comments in response to our plan including the Minnesota Office of Energy Security (the “Office” or “OES”), Izaak Walton League of America-Midwest Office, the Union of Concerned Scientists, Fresh Energy, the Minnesota Center for Environmental Advocacy (“MCEA”), Minnesota Chamber of Commerce, Excelsior Energy, and the Prairie Island Indian Community. We appreciate the comments provided by the Parties, who have raised issues regarding our resource acquisition strategy and the interplay between our strategy and the state’s requirements for renewable energy and conservation.

Our December 14, 2007 filing provided a framework for meeting significant policy goals that were established by the Minnesota Legislature while continuing to meet our customers’ needs in a reliable, cost-effective and environmentally sound manner. Our Action Plan proposes a diverse mix of resources including coal, nuclear, hydro, wind, biomass and natural gas and results in a 22% reduction in carbon dioxide emissions from 2005 levels by 2020.

Since our filing, we have proceeded with steps to obtain formal approval for many of the resources that were proposed in our Action Plan. In February we filed for a Certificate of Need for an extended power uprate at the Monticello Nuclear Generating Station. We also filed a Certificate of Need application for additional dry cask storage to support life extension and an extended power uprate at our Prairie Island facility. We have issued requests for proposals ("RFPs") for both Company-owned and Community Based Energy Development ("C-BED") wind resources, and are working to complete power purchase agreements for other resources that will be filed with the Commission for approval. These proceedings, in conjunction with the Resource Plan docket, will allow the Commission to consider our proposals in a broader context and ensure that our Action Plan is in the public interest.

Based on parties' comments, we are proposing a change to our DSM goals. Both the OES and the MCEA recommended that we increase our DSM goals in this plan. We have updated our DSM goals in the plan to 1.3% of retail energy savings. However we continue to believe that the market changes necessary to achieve these stretching goals will take time. As the result we propose a transition to the 1.3% goal by 2012.

In these reply comments we have also taken the opportunity to examine some of the changes that have occurred since we filed our plan last December to test the plan's robustness. The last year has brought higher fuel and construction costs and slowing economic indicators. As a result, our forecasts of energy and demand over the 15-year planning period have been updated. We have provided a discussion of our most recent forecast information in these reply comments and have incorporated it into our Strategist analysis. We have also performed additional analyses to examine the effects of escalating capital costs and fuel prices on our plans. We are pleased to report that our plan is robust, does not change significantly, and provides a solid foundation for responding to the dynamic market conditions we face in the next several years. The analysis indicates we may be able to defer one peaking resource during the first five years of the plan and we have more time to refine plans regarding the conversion of the remaining coal fired units at Black Dog. The rest of our action plan remains unchanged, including our environmental leadership position.

Many of the comments we received were similar in nature or addressed similar topic areas. Rather than address each comment separately, we have organized

our Reply to Resource Plan Comments into topic areas. The remainder of our reply filing is organized as follows:

- Planning in a Dynamic Environment,
- Updated Modeling & Need Assessment,
- Update on Resource Acquisition Activities,
- OES Strategist Analysis,
- DSM,
- Renewable Energy Standard (“RES”),
- Nuclear Energy,
- Mid-Continent Area Power Pool (“MAPP”),
- Excelsior Energy’s Resource Option,
- Northern Flood Agreement Monitoring, and
- Conclusion.

I. PLANNING IN A DYNAMIC ENVIRONMENT

Since we filed our Resource Plan in December of 2007, we have seen changes in the economics affecting the electric utility industry. As a result of a nationwide economic downturn, we have seen a drop in our current sales, with further reductions projected in our demand and energy forecasts. The sluggish economy and a worldwide run-up in oil prices have also resulted in instability in the equipment and fuel markets, which has in turn increased the expected cost of new generating resources. As a result of these changes, we have revisited the major assumptions made at the time of our Resource Plan filing.

One of these assumptions is our load forecast. We decided to revisit our load forecast sooner. We have just completed this process and the revised forecast shows an approximate 300 MW reduction in projected demand growth over the next five years. While this change may sound significant, because of the flexibility of our plan, we are able to accommodate this change without disrupting plans that are already in process. We find that we can delay potentially the implementation of our Black Dog repowering project and in the near term use fewer combustion turbines and flexible short-term purchases to meet the smaller growth in customer needs.

The revised load forecast also affects the timing and magnitude of the Company’s renewable resource needs in the longer term. Because the renewable requirements in each jurisdiction are based upon a percentage of

retail sales, as projections of those sales decline we need to acquire fewer resources to comply. In addition, in 2008, South Dakota passed a renewable energy objective that has since been incorporated into our projected needs. With the addition of a South Dakota objective and the revised load forecast, the Company's total projected wind resource need in 2020 is now approximately 3,400 MW, about 500 MW lower than was proposed in our December filing.

Shortly after we filed our Resource Plan in December 2007, natural gas prices started an upward trend that peaked in early July 2008 with an approximate 75% increase over the period. Prices have since fallen nearly as dramatically. Current long-term indicators have led us to increase projected natural gas prices by 10% in this update.

Capital costs of new resources also have continued to rise. The projected cost of generic gas-fired combustion turbines and combined cycle plants as well as generic wind generating facilities have increased 20% to 30% over what was assumed in the original analysis. Adding to the uncertainty of wind costs is the fact that Congress has yet to extend the Federal Production Tax Credits ("PTC") for renewable resources. To better evaluate the potential costs of complying with our renewable energy requirements, we have developed an expanded analysis that examines both additional assumptions for the PTC expiration and the impacts of installing lower levels of wind than required to meet our RES requirements.

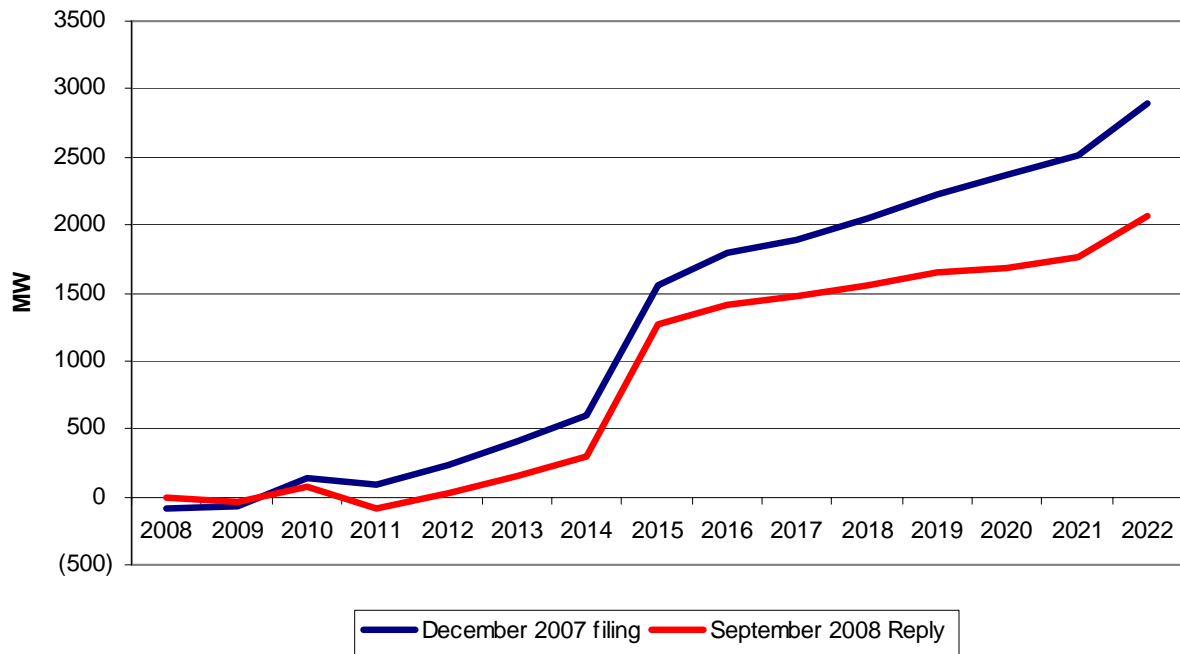
Additional uncertainties exist on the policy side. For example earlier this summer, the D.C. District Court of Appeals struck down the Clean Air Interstate Rule ("CAIR"), causing the market value of Sulfur Dioxide (" SO_2 ") and Oxides of Nitrogen (" NO_x ") allowances to decline. While the Environmental Protection Agency has until September 24, 2008 to appeal this ruling, the fact remains that there is at minimum a short-term delay in the implementation of additional environmental regulations.

The result of our additional modeling efforts indicates that we have developed a modular, flexible plan that can respond well under a variety of conditions. Our updated modeling efforts demonstrate that only small changes are needed in the size and timing of various resource additions, and that our proposed upgrades to existing units and the extension of the Manitoba Hydro contract are still cost effective. This update demonstrates that our Action Plan is robust under a number of assumptions, and its approval and implementation will serve our customers well for many years to come.

II. UPDATED MODELING AND NEED ASSESSMENT

In our December filing, we projected a resource deficit that began at 387 MW in 2012 and grew to 2,800 MW by 2022. This deficit was based on a forecast that was conducted in September 2007 and proposed DSM savings of 1.1% of retail energy. Our updated model includes both a lower forecast and a higher level of DSM savings, resulting in a lower resource deficit throughout the planning period.

Resource Needs 2008-2022



A. FORECAST

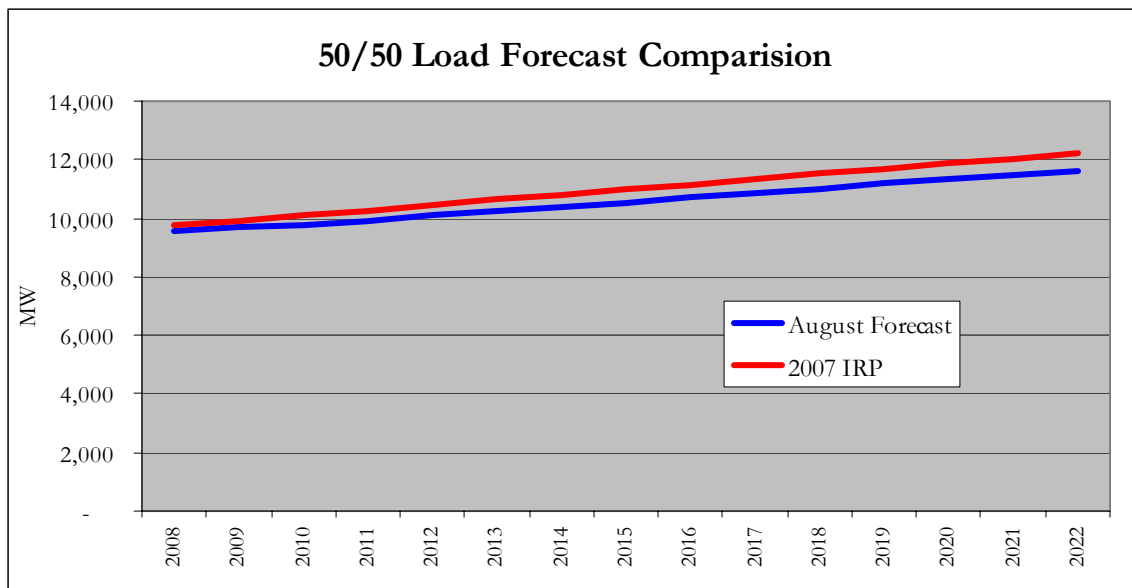
Our September 2008 forecast reflects updated assumptions about economic activity and energy loss factors. The latest energy forecast is 2,347 GWh lower in 2012 and 3,888 GWh lower in 2023 than the energy forecast developed for our December 2007 filing. The peak demand forecast is 374 MW lower in 2012 and 613 MW lower in 2023 than the previous forecast.

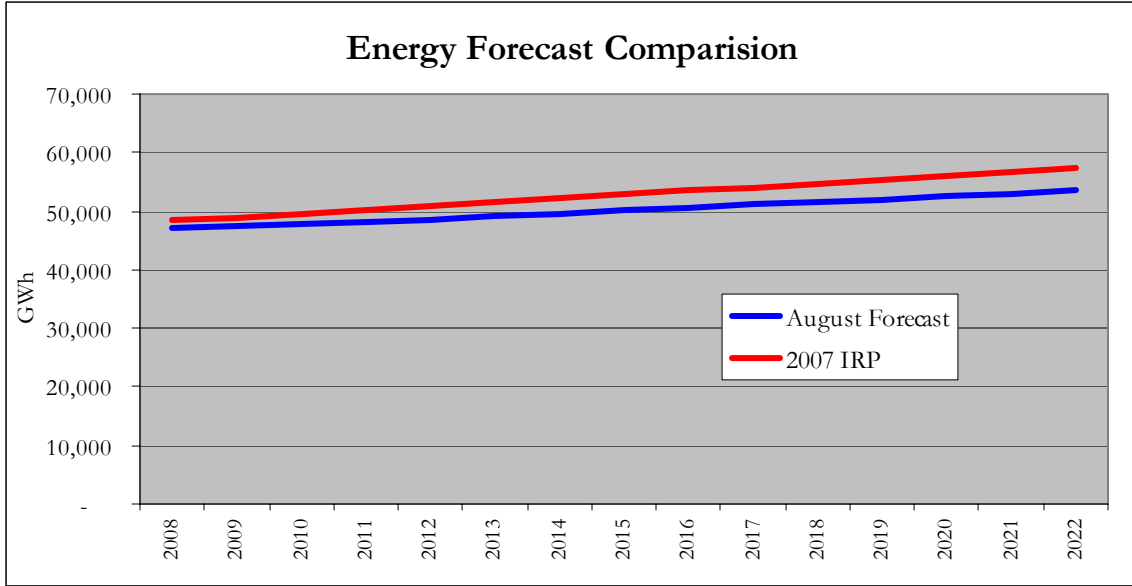
Economic activity in the Company’s service territory currently is weaker than was forecasted for our December 2007 filing and the recovery from this economic slowdown is forecasted to occur later than previously expected. The 2007 forecast of total employment in the Minneapolis-St. Paul metropolitan

area projected employment growth in 2007 to equal 1.1 percent, followed by 1.5 percent growth in 2008 and 1.7 percent growth in 2009. Actual employment growth in 2007, however, reached only 0.6 percent, while employment in 2008 is now predicted to show a 0.3 percent decline, followed by growth of only 0.7 percent in 2009. Other economic indicators such as population and real Gross Metropolitan Product also show reduced rates of growth for 2008 and 2009. This weaker economic outlook results in a lower energy and peak demand forecast than that filed in our December 2007 Resource Plan.

The revised forecast reflects the fact that current levels of energy sales and peak demand are growing at a slower rate than previously forecasted. In addition to the present economic weakness that is contributing to this slowdown in sales and peak demand growth, we believe that customers may be implementing additional conservation measures to help lower their energy consumption.

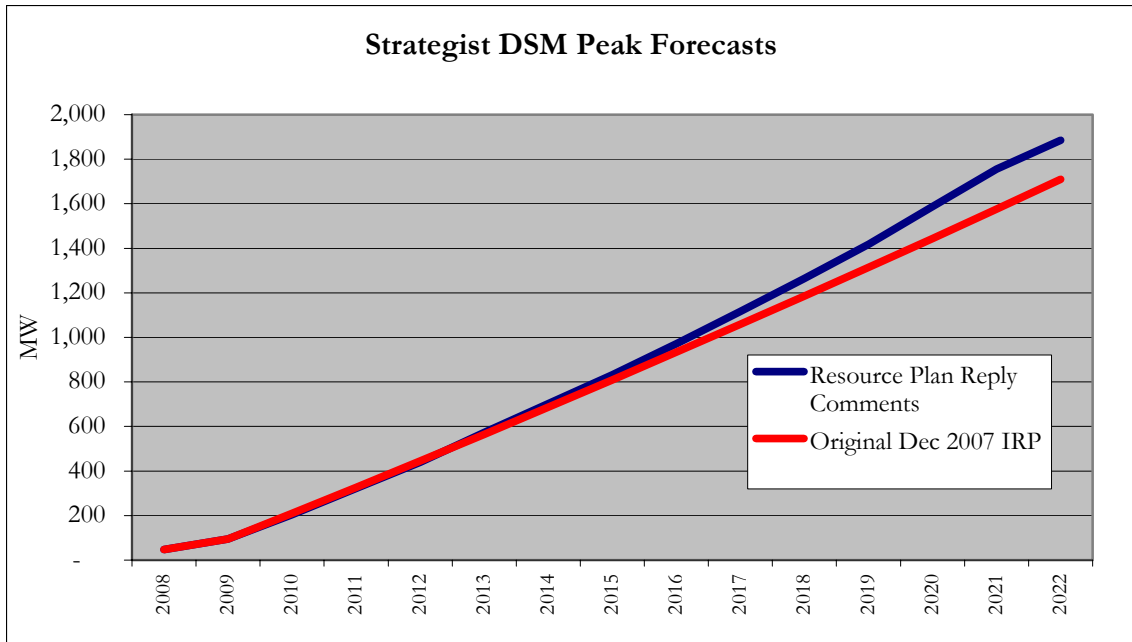
The energy loss factors used to calculate the losses associated with the sales forecast have also been re-estimated based on the five-year historical average loss factor for the time period 2003-2007. These new loss factors are lower than the factors previously used, resulting in a lower forecast of losses and, therefore, a lower forecast of total energy sales. The updating of the loss factors accounts for one-fourth to one-third of the overall change in the forecast of total energy.

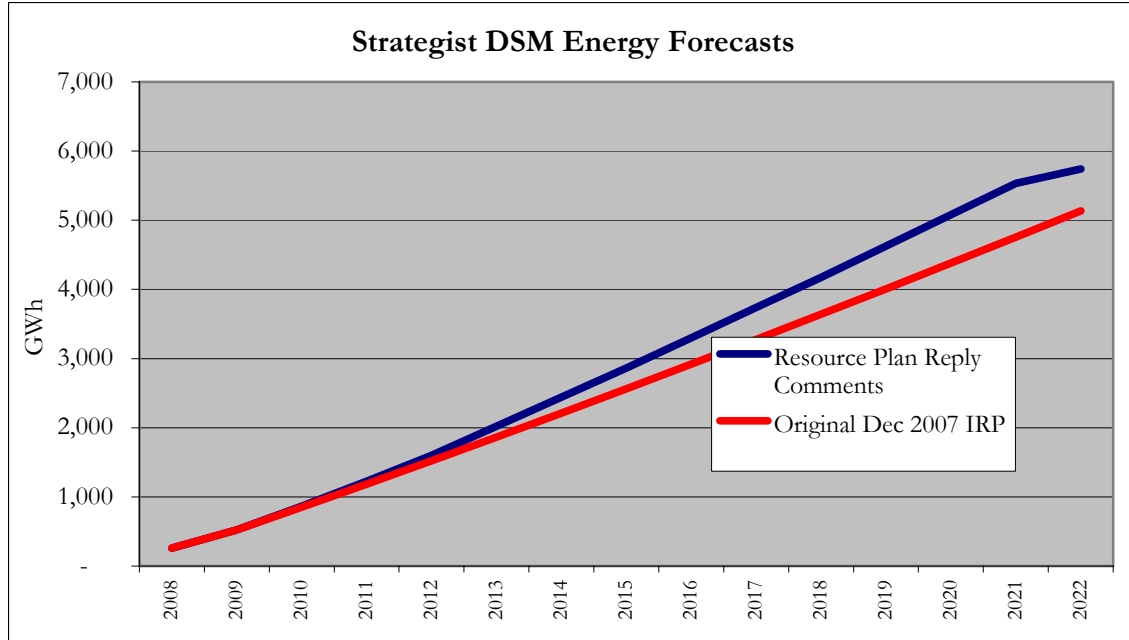




B. DSM

As discussed below, our updated DSM proposal in this filing starts at 1.15% savings in 2010 and grows to 1.3% annual savings by 2012. This results in a 1,880 MW (15%) reduction in peak load in 2022 and an energy reduction of 5,740 GWh.



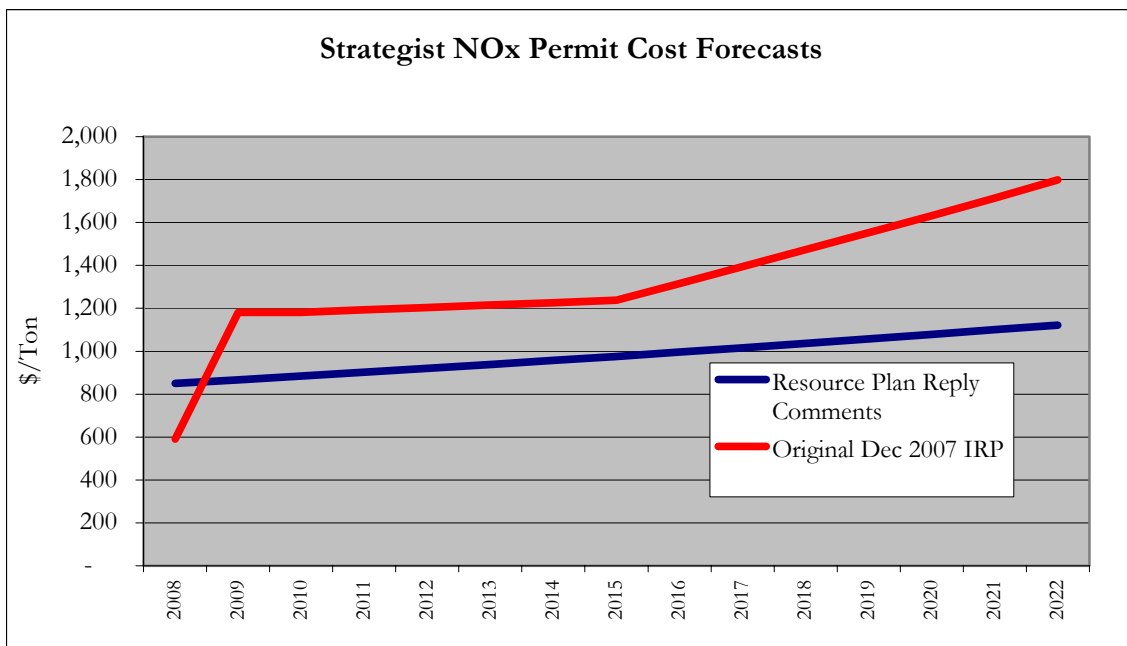
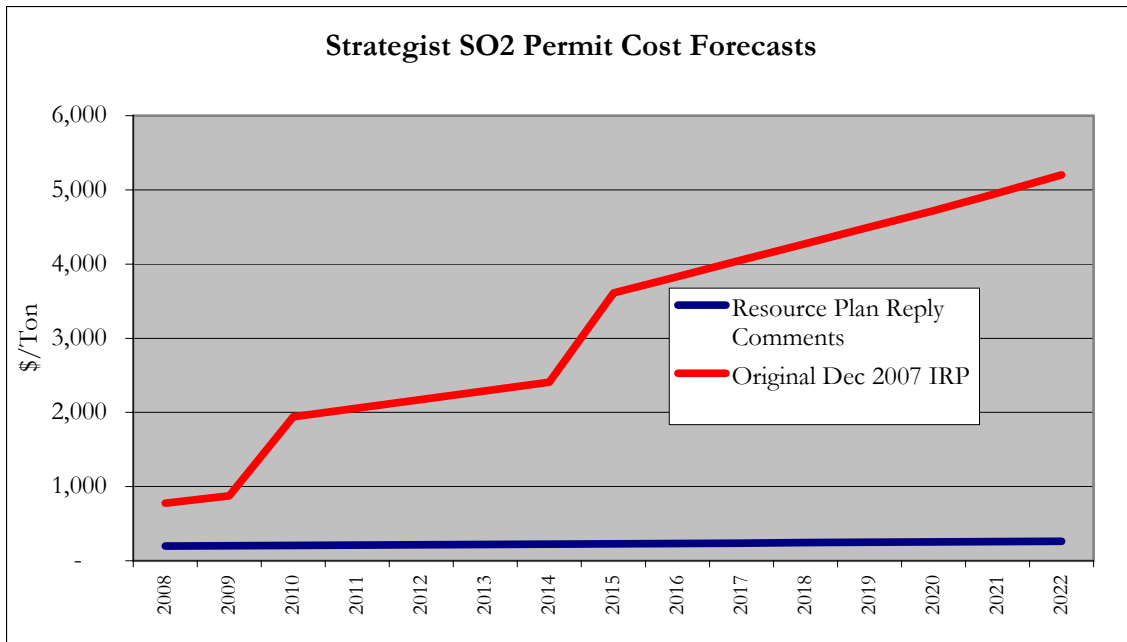


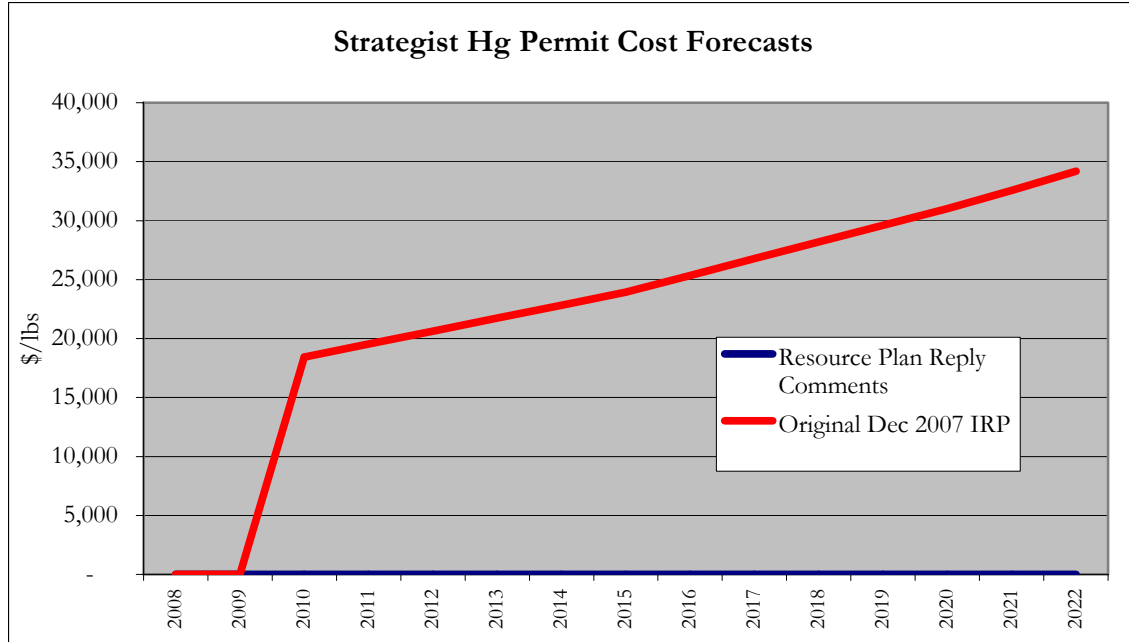
C. CAIR & CAMR

The recent rejection of the CAIR and the Clean Air Mercury Rule (“CAMR”) has changed our emissions regulation framework. In our December 2007 filing, we modeled SO₂, NO_x, and Mercury (“Hg”) allowances and allowance prices based on the CAIR and CAMR framework. Without these regulations there is uncertainty about costs associated with emission allowances.

For these response comments, the Strategist model was updated with recent market prices for SO₂ and NO_x and the current allocations under Title IV of the Clean Air Act. Costs for Hg allowances were completely eliminated from the model, although our models still include the capital and operating costs of complying with the Minnesota Mercury Emissions Reduction Act (“MMRA”). Although we have made these changes, we expect that CAIR and CAMR will eventually be replaced with new regulations that could contain a similar allowance framework as the rules that were recently vacated. There appears to be renewed interest in a multi-pollutant utility emission reduction bill in Congress as well as a targeted legislative reinstatement of CAIR. As a result, we have retained the emission allowances and allowance prices used in our December 2007 filing as a sensitivity analysis.

Attachment C Schedule 1
2007 IRP Reply Comments_9-5-08





D. BLACK DOG REPOWERING

In our December 2007 filing, we indicated our intention to study repowering options at our Black Dog Generating Plant and report back to the Commission. For purposes of that filing, we modeled the retirement of Black Dog units 3 and 4, which are fueled with coal, and replacing them with a 300 MW 1x1 combined cycle (“CC”) unit.

We have been conducting an extensive study of Black Dog options. Results indicate that a larger plant, up to 700 MW, may be more cost effective than the 300 MW option. However, with the uncertainty surrounding our load forecast and the future of natural gas prices, we believe it may be reasonable to delay such a large addition to 2015 or 2016. This delay will not impact our long term carbon reduction goals and replaces a generic 600 MW CC unit added in 2015 in our December 2007 filing.

E. OTHER STRATEGIST MODIFICATIONS

As discussed in our June comments, the Company has moved from the MAPP reserve-sharing group to the Midwest/MISO groups. This move changed our reserve planning standards. Since our June comments we have continued to refine our evaluation of reserve margins and our strategy for compliance. We have made some small modifications to our estimates of accredited capacity

and have revised our strategy for short-term capacity purchases, allowing them to float between 0 and 400 MW to help optimize the size and timing of larger resource additions.

We also updated the model to include revised in-service dates for some wind projects and a slightly reduced total wind expansion plan. The lower forecasts have reduced the amount of wind necessary to meet the Minnesota RES. While our December 2007 filing included approximately 2,900 MW of wind additions, the revised plan includes only 2,600 MW.

Finally the Company used the OES's suggested \$17/ton for CO₂ and performed a sensitivity analysis using \$4/ton and \$30/ton to comply with the Commission's December 2007 Order establishing estimates of the future cost of CO₂ regulations.

F. IMPACTS ON OUR PREFERRED PLAN

A lower demand forecast, increased DSM, and the prospect of a revised Black Dog project timing shifts the need for resources identified in our original filing. The updated preferred plan eliminates two CTs that were proposed for 2012 and instead adds a single peaking unit in 2014. The larger combined cycle unit at Black Dog replaces the proposed 2015 CC, and defers the need for additional new capacity until 2019. In 2019 Strategist now selects a CT instead of the CC that was selected in the December preferred plan

The total present value of revenue requirements ("PVRR") for the updated expansion plan is slightly lower than our December 2007 plan. Lower emission costs, a lower load forecast, and more DSM offset the cost increases in fuel and capacity. Our proposed upgrades at the Sherco and nuclear facilities as well as the Manitoba Hydro contract extension continue to be cost effective and integral to the updated plan.

Attachment C Schedule 1
 2007 IRP Reply Comments_9-5-08

**Aug 2008 Reply Comments Preferred Plan -
 August Forecast**

PVRR \$59,456,063 (\$000)

	Planned Additions	Combined Cycle	Combustion Turbine	Coal With CO2 Seq	Wind Additions
2008		High Bridge CC 624MW			
2009	RAHR 12MW	Riverside CC 511MW			250 MW
2010					260 MW
2011	Monticello 68MW		160MW		400 MW
2012	Sherco 2 25MW Sherco 3 10MW				250 MW
2013	Sherco 1 44MW PI 1 79MW				100 MW
2014			160 MW		100 MW
2015	Manitoba Hydro 375MW Manitoba Hydro DIV 350 PI 2 79MW	Black Dog Repowering 750 MW			100 MW
2016					100 MW
2017					100 MW
2018					100 MW
2019			160 MW		200 MW
2020					200 MW
2021	Manitoba Hydro 125MW				100 MW
2022		600 MW			100 MW

Original Dec 2007 IRP Preferred Plan

PVRR \$60,054,763 (\$000)

	Planned Additions	Combined Cycle	Combustion Turbine	Coal With CO2 Seq	Wind Additions
2008		High Bridge CC 624MW			
2009	RAHR 12MW	Riverside CC 508MW			409 MW
2010					200 MW
2011	Monticello 68MW		160MW		400 MW
2012	Sherco 2 30MW Sherco 3 10MW		320 MW		200 MW
2013	Sherco 1 44MW PI 1 83MW	Black Dog Repowering 300 MW			200 MW
2014					200 MW
2015	Manitoba Hydro 375MW Manitoba Hydro DIV 350 PI 2 87MW	600 MW			200 MW
2016					200 MW
2017					200 MW
2018		600 MW			200 MW
2019					200 MW
2020					200 MW
2021	Manitoba Hydro 125MW				
2022		600 MW			100 MW

Attachment C Schedule 1
 2007 IRP Reply Comments_9-5-08

Expansion Plan Changes		PVRR		-\$598,700 (\$000)	
	Planned Additions	Combined Cycle	Combustion Turbine	Coal With CO2 Seq	Wind Additions
2008					
2009	0 MW	0 MW	0 MW	0 MW	-159 MW
2010	0 MW	0 MW	0 MW	0 MW	-99 MW
2011	0 MW	0 MW	0 MW	0 MW	-99 MW
2012	0 MW	0 MW	-320 MW	0 MW	-49 MW
2013	0 MW	-300 MW	-320 MW	0 MW	-149 MW
2014	0 MW	-300 MW	-160 MW	0 MW	-249 MW
2015	0 MW	-150 MW	-160 MW	0 MW	-349 MW
2016	0 MW	-150 MW	-160 MW	0 MW	-449 MW
2017	0 MW	-150 MW	-160 MW	0 MW	-549 MW
2018	0 MW	-750 MW	-160 MW	0 MW	-649 MW
2019	0 MW	-750 MW	0 MW	0 MW	-649 MW
2020	0 MW	-750 MW	0 MW	0 MW	-649 MW
2021	0 MW	-750 MW	0 MW	0 MW	-549 MW
2022	0 MW	-750 MW	0 MW	0 MW	-549 MW

G. LOAD SENSITIVITIES

With lower forecasts there is some risk of demand increasing faster than predicted and resource additions being inadequate to meet demand. Under the base assumptions of our revised forecast peak demand and energy have average growth rates of 1.41% and 0.91% respectively during the 15-year planning period. In a high load sensitivity analysis we have varied these growth rates by 20% to 1.69% and 1.09%. In the high load scenario the expansion plan includes an additional CT in 2012. In order to adequately respond to this contingency we may need to begin this resource acquisition process in 2009. We will continue to monitor developments and inform the Commission immediately if it appears that resources will be needed earlier than is indicated in our updated action plan.

**Aug 2008 Reply Comments Preferred Plan -
 August Forecast - High Load Growth Sensitivity PVRR \$62,355,907 (\$000)**

	Planned Additions	Combined Cycle	Combustion Turbine	Coal With CO2 Seq	Wind Additions
2008		High Bridge CC 624MW			
2009	RAHR 12MW	Riverside CC 511MW			250 MW
2010					260 MW
2011	Monticello 68MW		160MW		400 MW
2012	Sherco 2 25MW Sherco 3 10MW		160 MW		250 MW
2013	Sherco 1 44MW PI 1 79MW				100 MW
2014			160 MW		100 MW
2015	Manitoba Hydro 375MW Manitoba Hydro DIV 350 PI 2 79MW	Black Dog Repowering 750 MW			100 MW
2016					100 MW
2017		600 MW			200 MW
2018					100 MW
2019					100 MW
2020					200 MW
2021	Manitoba Hydro 125MW				200 MW
2022			160 MW		100 MW

III. UPDATE ON RESOURCE ACQUISITION ACTIVITIES

Resource Planning is not the only regulatory venue in which our resource acquisition program is judged. Since our December filing, we have proceeded with steps to obtain formal approval for many of the resources that were proposed in our Action Plan. In February we filed for a Certificate of Need for

an extended power uprate at the Monticello Nuclear Generating Station. We also filed a Certificate of Need application for additional dry cask storage to support life extension and an extended power uprate at our Prairie Island facility. We have issued RFPs for both Company-owned and Community Based Energy Development ("C-BED") wind resources, and are working to complete power purchase agreements ("PPA") for other resources that will be filed with the Commission for approval. These proceedings, in conjunction with the Resource Plan docket, will allow the Commission to consider our proposals in the broader context and ensure that our Action Plan is in the public interest.

As we look beyond these acquisitions to the resources we have not yet identified other than by type and size, we note that we are pursuing opportunities to locate resources in particular, additional renewable resources, in all of our jurisdictions: Minnesota, Wisconsin, North Dakota, South Dakota and Michigan. Regulators and stakeholders in our other jurisdictions have strongly encouraged us to increase our investments in their states. As is the case with investments in Minnesota, this desire is driven by increased interest in energy reliability and economic development. We will seek to achieve a balance with regard to investment in all of our jurisdictions such that our customers across the system continue to receive reliable and low-cost energy.

The sections that follow provide an update for the Commission and interested parties.

A. 2011 PEAKING RFP

We issued our RFP for 160 MW of peaking capacity in November 2007. In response to the RFP, we received 11 proposals from eight developers. In early June 2008 we reaffirmed the need for this resource and began due diligence on the best three proposals. In August 2008 we selected two proposals for further negotiation and we expect to bring a completed PPA to the Commission before the end of this year.

B. ADDITIONAL DRY CASK STORAGE AND POWER UPRATES AT OUR NUCLEAR FACILITIES

We filed our Certificate of Need application for an extended power uprate at our Monticello Nuclear Generating Station on February 14, 2008 (Docket No. E002/CN-09-185). Parties have pre-filed testimony in this proceeding, which

is scheduled for hearings in October. On May 16, 2008 we filed two Certificate of Need (“CON”) applications for Prairie Island. Docket No. E002/CN-08-509 is for our extended power uprate and Docket No. E002/CN08-510 is for additional dry cask storage to support extending operation through 2034. Both filings have been accepted as complete and referred to the Office of Administrative Hearings.

C. C-BED ACQUISITION

Our 2007 C-BED solicitation was disappointing, yielding no contracts from over 400 MW of proposals that we selected for negotiation. The lack of success was due to a number of factors, including turbine availability and interconnection queue position. In June 2008 we issued another C-BED RFP, in this case focusing proposals on those that already have interconnection agreements or are in the MISO interconnection study group 5. On July 11, 2008 we received proposals totaling 739 MW. After screening these proposals for price and interconnection status, we have selected 340 MW with which to negotiate contracts. In addition to projects with favorable queue positions, we have also selected a project that will benefit from MISO queue reform and one that may be interconnected pursuant to the Minnesota Distributed Generation Survey. We hope to file completed contracts with the Commission by the end of October.

D. COMPANY OWNED WIND ACQUISITIONS

We have received several proposals in response to our solicitation for 500 MW of wind for Company ownership through a build-transfer process. We have completed due diligence on the proposals and have selected a number of projects for negotiation. We expect to file for appropriate regulatory approvals of our selections in October 2008.

E. MANITOBA HYDRO CONTRACT EXTENSION

We have narrowed our issues with Manitoba Hydro on our contract extension and have exchanged several versions of a draft contract. We expect to initiate a proceeding for approval of the contract extension by the end of 2008.

IV. OES Strategist Analysis

In their June 16, 2008 Comments on our 2007 Resource Plan the OES presented their Strategist analysis. This is the first docket in which the OES has used Strategist to evaluate our resource plan. We believe the OES's use of Strategist will provide more transparency to the resource planning and acquisition process and may enhance the collaboration between the Company and regulators in developing a sound energy plan.

A. LOAD AND DSM FORECASTS

The OES recommends approval of our peak demand forecast and a higher level of DSM in their comments. We arrived at our revised forecast used in these reply comments using the methodology as suggested by the OES in their comments.

B. STRATEGIST ISSUES AND ASSUMPTIONS

The OES identified several issues when reviewing the Company's Strategist model. With literally thousand of inputs it is inevitable that errors will occur and we appreciate their thorough review of the model. Based on the OES analysis, we have corrected four errors in the model:

- Calculation of the real discount rate,
- Mercury emission rates at Black Dog,
- Dispatch cost for CO₂, SO₂, NO_x and Hg, and
- Emergency energy costs in 2042-2047.

In addition the OES suggested the use of some alternative inputs for externalities, CO₂ costs, the peak forecast, and accredited capacity.

The OES used the Commission's high externality values as the base assumption in their analysis. We also used these values, but as a sensitivity rather than a base assumption, and presented the results in our analysis. We believe that either approach is acceptable as long as externalities are quantified. However it should be noted that the forecasted cost of emission regulation is currently far greater than the externality costs calculated in Strategist. In the modeling for the December 2007 filing the forecast NPV for CO₂, SO₂, NO_x and Hg emissions were \$6.8 billion based on predicted allowance prices at that

time. The NPV of PM10, CO, and Pb were \$168 million using the externality costs established by the Commission.

The OES also used a base CO₂ value of \$17/ton and ran sensitivities at \$4/ton and \$30/ton based on the Commission's December 2007 order establishing estimates of future carbon regulation. This Order was issued after we filed our plan in December 2007. We have included these values in the analysis we have developed for these reply comments.

Finally, the OES adopted the use of a 50th percentile peak demand forecast and maximum dependable capability ("MDC") accreditation values for thermal units to be consistent with the expected standards for the MPRSG. We used the MAPP standards of the 90 percent peak forecast and uniform rating of generation equipment ("URGE") in our December 2007 filing. At the time we filed our resource plan in December 2007, there was still a great deal of uncertainty regarding the MPRSG standards. As noted in our June 2008 comments, much of that uncertainty has now been resolved and we have also adopted the 50th percentile peak and MDC accreditation as base inputs.

C. OES'S PREFERRED PLAN

The OES's preferred plan is almost identical to ours. The small discrepancies are likely due to the OES's use of the 1.3% DSM standard as a base input. We believe that the similarities in the two plans demonstrate the robustness of our expansion plan and the reasonableness of the modeling techniques and assumptions used.

V. DSM

A. WE PLAN TO PURSUE THE 1.3% CONSERVATION GOAL RECOMMENDED BY THE OES

Both the OES and the MCEA commented that our DSM goals fell short of the Minnesota Legislature's requirements. In addition, the OES noted that our 1.3% scenario appeared to be more cost effective than the 1.1% goal we proposed. As a result, the OES recommended that we adopt the 1.3% goal.

The Company is committed to achieving the aggressive savings goals established in the Next Generation Energy Act of 2007. We accept the OES's recommended 1.3% energy savings scenario. However, we respectfully request to increase our annual savings to this level over a few years in order to allow

time to ramp up program activities, promote market changes, develop indirect program savings methodologies and evaluate program results. Under this timeline, the Company will strive to achieve a 1.15% savings goal in 2010, 1.2% in 2011 and 1.3% in 2012. In contrast to previous resource plan proceedings, we will set annual percent savings goals for the resource plan period, as opposed to overall savings targets for the fifteen year period. Specific annual savings targets will be set in our CIP Triennial Plans. The savings at these goal levels will be calculated by applying the percent savings goal established in this proceeding to the average of the most recent three-year weather normalized sales less CIP exempt customers. The energy savings goals used in this response are estimates based on the current sales forecast. As with previous resource plan filings, we set annual forecasted percent savings goals for the resource plan period. Specific annual savings targets will be set in our CIP Triennial Plans.

In these Reply Comments, we will provide a context for our goals, outline factors that limit the speed and extent with which we can increase program achievements, and discuss the contribution of indirect programs, electric utility infrastructure improvements and our strategies for meeting these goals.

B. THE GOALS IN CONTEXT

When discussing the savings goals as a percent of sales, it is easy to think that each increment of 0.1% of sales represents a small number and small increase to the savings goal. However, with approximately 1.2 million electric customers in Minnesota and annual retail sales of over 32 billion kWh, a 0.1% increase to the goal equals 32 million kWh or 32 GWh. This is approximately 15% of our total 2007 DSM program achievements, and is equivalent to the achievements of one of our most successful programs, CEE One Stop Shop for Lighting. Our 2007 achievements represent our best efforts to bring in energy savings, requiring an investment of over \$47 million and achieved savings of approximately 0.83% of retail sales.

The 2010 DSM goal requires an additional 99 GWh per year over our reported 2007 DSM savings, representing a 38% increase and total annual savings of approximately 358 GWh. The additional 99 GWh savings are greater than the savings achieved by our most successful 2007 program, the Energy Design Assistance Program. It is also greater than the combined savings achieved by our Lighting Efficiency, Custom Efficiency and Motor Efficiency programs, which are some of our best performing and longest running programs. To meet

the expanded goal, we will have to add the equivalent of an Energy Design Assistance and Custom Efficiency program every single year.

A 1.3% goal requires an additional 146 GWh annually, representing a 56% increase over our reported 2007 DSM savings and total annual savings of approximately 405 GWh. The additional 146 GWh goal is over ten times the savings achieved by the entire residential program portfolio in 2007. It is approximately equal to the savings achieved by our three most successful programs—Energy Design Assistance, Lighting Efficiency and the CEE One Stop Shop for Lighting program. To meet the goal, we will have to add the equivalent of Energy Design Assistance, Lighting Efficiency and the CEE One Stop Shop programs every single year.

New programs take time to become established and productive. For example, our Vending Efficiency Program was launched in 2007. It achieved 0 kWh in 2007 and is projected to achieve 0.5 GWh of savings in 2008. Our Segment Efficiency Program was also launched in 2007 and achieved 0.2 GWh savings and is projected to achieve 8 GWh in 2008. This is typical of new programs. It normally takes three to six months to develop a new program and over a year for the program to become established. While the Company plans to add several new programs in 2010, our experience shows that we cannot expect the new programs to contribute significant savings in their first and second years.

Further, we are anticipating challenges to expanding the amount of savings achieved in the residential sector due to the national phase out of standard incandescent bulbs and increasing market penetration of compact fluorescent light bulbs (“CFL’s”). The phase out will reduce the amount of savings we can capture in our Home Lighting program, which comprises approximately 75% of total savings from our residential sector. The program’s success is due to the large energy differential between incandescent bulbs and CFL’s and the low cost and widespread availability of CFL’s, making it easy and cost effective for residential customers to participate. We expect to meet approximately half of the overall savings gap in the 2010-2011 period through an aggressive CFL campaign. However, there is no commercially available and cost effective high efficiency alternative to the CFL on the near horizon, meaning that we will have to find other measures or programs to fill that gap after the federal standard becomes effective. Beyond CFL’s, the common residential electric conservation measures, such as appliance and air conditioner replacements are more expensive, which can be a barrier to participation and limit achievements from the residential sector.

As we discussed in our December 2007 filing, the 1.1% savings goal we proposed aligns very closely with our most recent DSM Potential Study, completed in 2004 with updates in 2006 and 2007. While the Company recognizes that potential studies have limitations, we believe that our study continues to be current and valid. The OES is considering doing a statewide potential study. Thus, we will review the OES study assumptions for future applicability.

MCEA argues that when DSM is allowed to compete as a discrete resource with generation or a forward capacity market in a planning model, higher levels of DSM are selected and should therefore serve as the basis for higher DSM goals. However, there are three differences in DSM to consider:

1. A model may select very high levels of DSM, but that does not mean that the DSM is achievable with an in-service date like a generating facility.
2. The forward capacity market is seeking capacity or kW resources, not energy or kWh resources. Therefore, the DSM resources being bid in the ISO-NE forward capacity market are largely demand response, load management and distributed generation measures, which do not necessarily contribute energy savings, which is the metric for the Minnesota goal.
3. Comparing energy efficiency potential across states and regions is complex. For example, during the 1990s, DSM activity in the Northeast was minimal, which means that there may be a greater number of cost-effective savings opportunities still available in that market. In contrast, Minnesota's programs have operated uninterrupted since the mid 1980's, continuously capturing the available savings potential.

C. CHALLENGES

The new goals will require a comprehensive retooling of our conservation programs. There are several factors that make meeting the 1.3% goal challenging. We will work hard to address and overcome these factors, but believe that it will take a few years to bring about the needed changes in the marketplace to make this possible.

History of DSM

We have been offering DSM programs since the mid-80's. This means that we have already captured a significant share of the most cost-effective and easiest

to achieve opportunities. For example, we estimate that approximately 70% of the commercial lighting in our service territory has already been retrofitted with energy efficient equipment (e.g. T-8 light bulbs and electronic ballasts). Absent significant technological advances in lighting, there is limited potential to capture additional savings in the commercial lighting market.

Lack of Significant Technological Advances in Energy Efficient Technologies

New technologies and measures refresh the portfolio and create new savings potential, which is critical to meeting savings goals. For example, the introduction of T-8 lighting and compact fluorescent light bulbs (“CFLs”) in the mid-1990’s created significant and cost-effective savings potential in almost every commercial and residential building. However, subsequent technological advancements in lighting and other end-uses have been slower to develop and represent only marginal gains. For example, switching from a 65-watt incandescent bulb to a 15-watt CFL saves 50 watts, while switching from a CFL to an LED may only save 5-10 watts.

Multi-Year Program Sales Cycles

Many of our programs, including Custom Efficiency, Energy Design Assistance, Industrial Efficiency and Segment Efficiency, have sales cycles of up to five years due to the size and complexity of the project and customers’ operations and budgeting cycles. It can take well over a year to identify, study, pre-approve, implement, and measure and verify projects. For example, the average Custom Efficiency project takes nine months from project preapproval to payment of the final rebate. Prior to preapproval, we often spend a year or longer working with the customer to identify, solidify and budget for the energy-efficiency improvements with actual project completion often subject to economical and budget changes that can affect the actual completion date.

Our segment-specific programs such as Industrial Efficiency and Commercial Real Estate are designed to support 3-5 year implementation plans. Realizing achievements in these programs is a long-term process, requiring extensive customer contact and project scoping. While we have a number of projects already identified and in the scoping phase, these projects are not sufficient to close the gap between our historical level of achievement and the new goals.

Contractor/ Vendor Infrastructure

There must be an adequate pool of skilled contractors/vendors available across our service territory to perform the work. To successfully participate in our programs, contractors must be trained in our program offerings and program rules. They must actively promote our programs as well as be willing to work

within our program requirements. Thus, we may need to improve incentives to encourage further participation.

Market Barriers

Market barriers limit the implementation of energy efficiency actions. Our ability to meet the savings goals is dependent on overcoming these barriers.

Customers are often unaware that energy efficient options are available. For example, a customer purchasing a central air conditioner may not understand that air conditioner efficiency is represented by the Seasonal Energy Efficiency Ratio (“SEER”) rating with a base SEER of 13 and more efficient models at 14, 15 and 16 SEER. If the customer is only presented with direct cost information, he or she may not understand the benefits of the energy efficient equipment relative to the incremental cost.

We anticipate that meeting the new goals will require a dramatic increase in the volume of energy efficient equipment sales. It is critical that local vendors and suppliers maintain an adequate supply of high efficiency equipment. Even if a customer wants to purchase the most energy efficient equipment, it needs to be conveniently available for this to occur. In the central air conditioner example, a customer seeks to purchase a 15 SEER unit. If the contractor only has 13 SEER units available and convinces the customer that the 13 SEER unit is an efficient choice, there is no gain.

Sometimes customers hold strong preferences that will take time to change. For example, we currently offer CFLs at discounted prices or for free depending on the promotion. CFLs are easily installed, the customer makes little or no financial investment and they will save on their energy bills. However, customers don’t always like the color of the light, the amount of light or that they have to wait several seconds for the light to reach full power. Customers may choose to pay more on their electric bills if they prefer incandescent bulbs.

Occasionally the right energy efficiency choice does not match the customer’s business requirements or lifestyle preferences. For example, a family may find the available energy efficient refrigerator models are not the desired size, look, or color, or may lack features such as in-door water and ice. Many customers will not sacrifice these items for energy efficiency. Similarly, many businesses are not willing to trade off what they perceive to be the requirements of their business in order to achieve greater energy efficiency.

For many customers, particularly residential and small business customers, completing an energy efficiency upgrade seems like a hassle unworthy of their time. They do not have the time or resources to learn about and investigate energy efficiency options, find contractors, evaluate bids, manage the installation and complete rebate forms or make sure their contractor completes the rebate forms.

Even when cost-effective savings are identified, our experience is that customers will not adopt every energy efficiency measure that passes a simple payback test or other cost-effectiveness measures. There are financial factors that affect the willingness of customers to adopt energy efficiency measures.

Property Management firms that own or manage office or retail space make many of the decisions around building maintenance and equipment installation but frequently are not directly responsible for paying the energy bills. The tenants are responsible for the energy bills but are reluctant to pay for equipment upgrades for buildings they don't own. Although many retrofits such as lighting upgrades have short paybacks, the financial model is complicated because the party who is responsible for paying for the investment may not be the party who receives the financial benefit.

Customers have a limited amount of capital and therefore prioritize their capital spending. A common decision customers make is whether to invest in an energy efficiency measure that will save them operating dollars or to invest in an expansion that will increase revenue. If the profit from the revenue increase is larger than the reduction in costs resulting from energy savings, the customer's choice will likely be to expand. For the residential customer it might be a choice between adding extra insulation or a granite countertop. The granite countertop will generally increase the value of the home more than the unseen insulation.

We are committed to doing everything we reasonably can to overcome market barriers. We offer this information as a reminder that changes in behavior take time. It is important to recognize that energy savings require a customer to choose and implement energy efficiency in spite of market barriers. Influencing customers requires extensive marketing and advertising. We plan to dramatically increase marketing and advertising and strengthen and expand our partnerships with our trade allies, contractors and retailers, but expect that it will take time to change the way customers think and make decisions.

It is a commonly held belief that higher energy prices will result in higher levels of energy efficiency. However, it is uncertain to what degree customers, particularly residential customers, will pursue energy efficiency in response to higher electricity prices. Market research shows that electricity bills are generally not a major household expense and that the majority of residential customers are not certain where their electricity comes from or how their homes use electricity. If residential customers are aware, they tend to think about natural gas and home heating. A recent study by the Rand Corporation and the National Renewable Energy Laboratory found that over the past twenty years energy has been relatively inelastic to price, meaning that the response to price signals has been relatively small.¹

Business customers have a long history of implementing energy efficiency measures but will need to invest larger amounts to get to the next level of energy efficiency. Unfortunately, the next level of efficiency will result in lower efficiency gains per dollar spent than the first level. This impacts our ability to achieve greater savings, as the largest energy efficiency gains have historically come from business customers.

D. ELECTRIC UTILITY INFRASTRUCTURE PROJECTS

As part of the debate leading to new conservation goals it was anticipated that significant savings could be achieved by reducing losses in the production and transmittal of electric energy to supplement customer conservation efforts. While still preliminary there are some indications that the magnitude of improvements that wouldn't otherwise occur on the system may not be as great as anticipated. For example our Electric Utility Infrastructure project team has completed additional analysis on the Distribution Line Loss Reduction project cited on page 9-15 of our Resource Plan. While we are still researching and analyzing the issues, at this point, we believe that the initial savings estimates per feeder and the number of eligible feeders that could be added each year are lower than our original projections.

The Company will continue to work to identify additional projects that could qualify as electric utility infrastructure conservation projects. We are active participants in national initiatives dedicated to researching strategies to improve the efficiency of transmission and distribution systems, including Green

¹ "Regional Differences in the Price-Elasticity of Demand for Energy"
<http://www.nrel.gov/docs/fy06osti/39512.pdf>

Circuits and other initiatives managed by the Electric Power Research Institute (“EPRI”). We are optimistic that this research may identify future system efficiency opportunities.

E. SAVINGS FROM INDIRECT PROGRAMS

The Next Generation Energy Act of 2007 also allows utilities to include indirect savings from such things as improved energy codes and appliance standards, programs designed to transform the market or change consumer behavior, and other indirect efforts to promote energy efficiency and energy conservation. The Company welcomes this flexibility. However, methodologies have not yet been established to quantify savings and thus the contribution of these programs to our DSM goals is uncertain. We are committed to working with the OES and other stakeholders to clarify what may count as indirect program savings and are optimistic that consensus on methodologies to quantify savings will have emerged by the time of our 2013/2014/2015 Triennial Plan filing on June 1, 2012. Due to this uncertainty our current plan only includes savings from direct programs and electric utility infrastructure project achievements.

F. STRATEGIES FOR FUTURE GROWTH

The Company has identified and considered a number of strategies for growing DSM. In order to meet the new savings goals we will have to:

- add new measures, products and services;
- refine and expand existing products;
- improve sales and delivery channels;
- expand conservation marketing; and
- increase rebate levels.

We believe that the deliberate and measured implementation of these strategies will deliver increased savings. Our proposed phase-in of the 1.3% goal will provide the time needed to develop these new programs and study customer response.

We are committed to growing long-term sustainable and cost-effective programs. We believe a gradual and steady approach to building our programs is necessary to achieve sustained and dependable savings, as opposed to a rapid increase produced by inflated rebates or other “quick fix” strategies. A steady

approach allows us to grow our internal resources more efficiently and maintain more cost-effective program offerings. Additionally, we believe the phased-in goal reflects a more appropriate level of risk when considering our obligation to reliably meet customers' needs over the long term.

G. SUMMARY OF DSM ACTIVITIES

We will begin ramping up our efforts in 2009 and will further develop, expand and evaluate our efforts in the 2010/2011/2012 Triennial Plan period. We believe that these activities will position us to achieve the 1.3% energy savings goal in 2012.

Reaching the higher goals will require additional resources, including staff, customer programs and services, extensive marketing and higher rebates. We anticipate that we will need to dramatically increase marketing, advertising and program delivery budgets. This increased spending will reduce the overall cost-effectiveness of our programs, as the growth in spending is likely to outpace the growth in energy savings. This effect is intensified by the existing regulatory assessments and those authorized under the Next Generation Energy Act of 2007. Under the current incentive mechanism, a reduction in the cost-effectiveness of the portfolio results in a lower incentive. The Company believes that the incentive mechanism will have to be adjusted to avoid penalizing the Company for working harder and spending more to achieve the aggressive goals.

VI. RENEWABLE ENERGY STANDARD

In response to the Chamber comments, we conducted additional analysis on the impact of the RES. Our analysis included updated wind generation costs, differing assumptions for PTC expiration and lower amounts of wind, in 10% increments, than would be needed to meet the full RES. The results of our analyses agree with the findings of the OES, that an expansion plan that includes sufficient wind additions to meet the RES may not necessarily be the lowest cost option, but that the impacts on customers do not appear to justify a new course at this time.

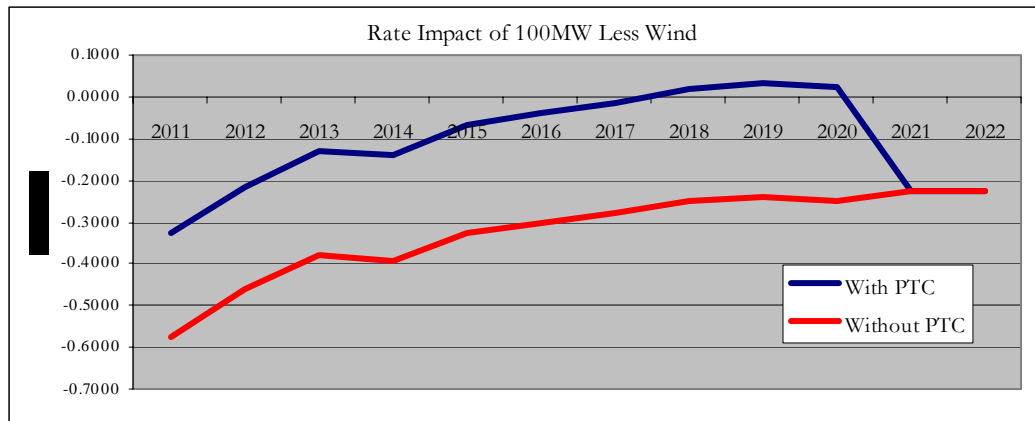
In the analysis used in our December 2007 filing, we concluded that with the PTC, wind energy was the least cost energy resource. However since that filing there has been a significant increase in the cost of wind turbines due to high demand and limited supply. For this reply comment analysis we increased our

estimate of the capital cost of wind by 25% and now find that wind is slightly more expensive than non-renewable options.

A. INCREMENTAL COST OF WIND

To investigate the incremental cost to customers for wind, we compared the cost of our preferred plan to the cost of the same plan less 100MW of wind in service in 2011. The results were that less wind decreased total PVRR and average rates by a very small amount.

	Total PVRR (\$millions)	
	With PTC	Without PTC
Preferred Plan	\$59,456	\$60,184
Preferred Plan Less 100MW Wind	\$59,412	\$60,063
Change	(\$44)	(\$120)
% Change	-0.07%	-0.20%



B. PRODUCTION TAX CREDIT

In our December filing, we assumed as a base case that the PTC for wind energy would be extended through 2015. The Chamber criticized this assumption, arguing that given the history of the PTC, it is unlikely to be extended. We continue to believe that the PTC will be extended. The PTC enjoys bipartisan support and has already been extended five times since its passage in 1994, with three of those extensions occurring retroactively. However, in response to the Chamber’s comments we analyzed additional scenarios to test the impacts of earlier PTC expiration on our Preferred Plan’s PVRR. In our original analysis we assumed that the PTC would expire in 2015.

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For this analysis we also evaluated our expansion plan assuming the PTC expired in 2012 and 2009.

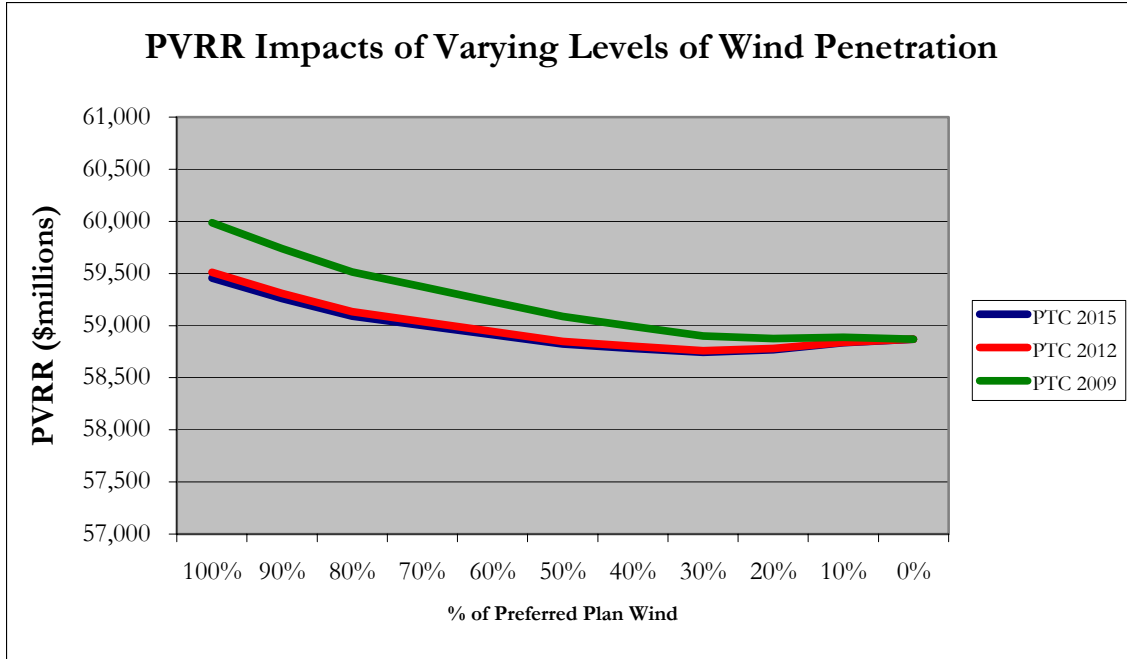
The Chamber also requested that we identify a reference case that does not use RES compliance as a basic assumption, but instead selects the optimal amount of wind that results in a least cost expansion plan. We have met with the Chamber and explained that Strategist is unable to perform such an optimization because there are so many different combinations of wind and thermal resources that the limits of Strategist’s memory capacity are exceeded. As an alternate approach we increased the wind that was included in the base case in 10% increments and noted its impact on the PVRR. The results of this analysis, including the impacts of updated price and earlier PTC expiration, indicate that a lower level of wind than the RES results in a lower total PVRR, but the overall impact on costs is small.

PVRRs

	PTC Expiration		
	2015	2012	2009
100%	59,456	59,510	59,986
90%	59,261	59,309	59,737
80%	59,090	59,133	59,514
70%	59,001	59,039	59,372
60%	58,912	58,944	59,229
50%	58,823	58,850	59,088
40%	58,780	58,802	58,992
30%	58,743	58,759	58,901
20%	58,769	58,779	58,875
10%	58,834	58,840	58,887
0%	58,869	58,868	58,869

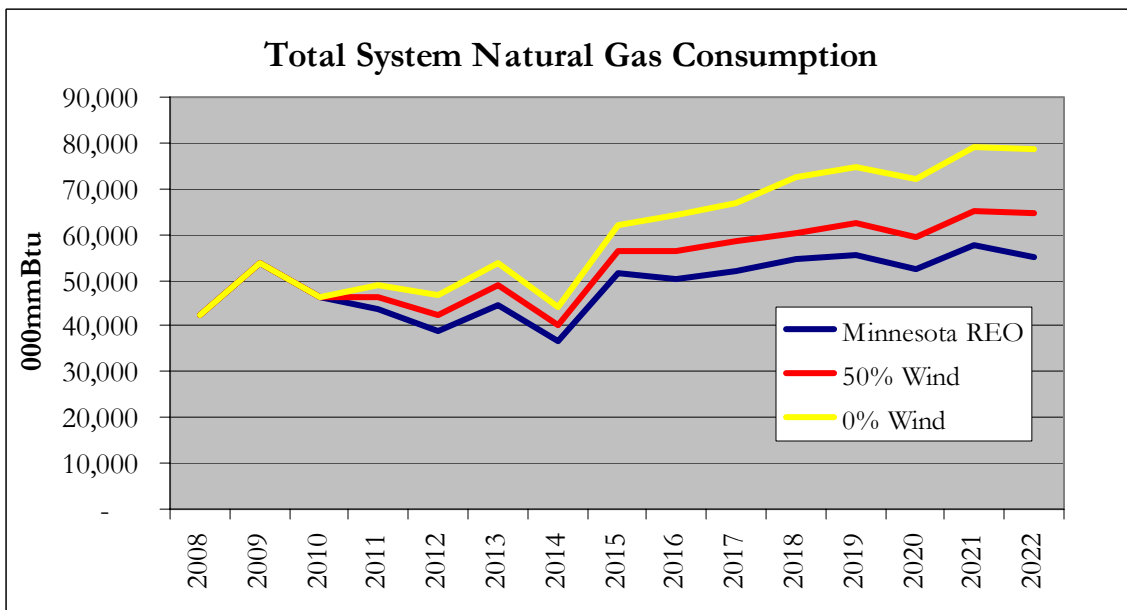
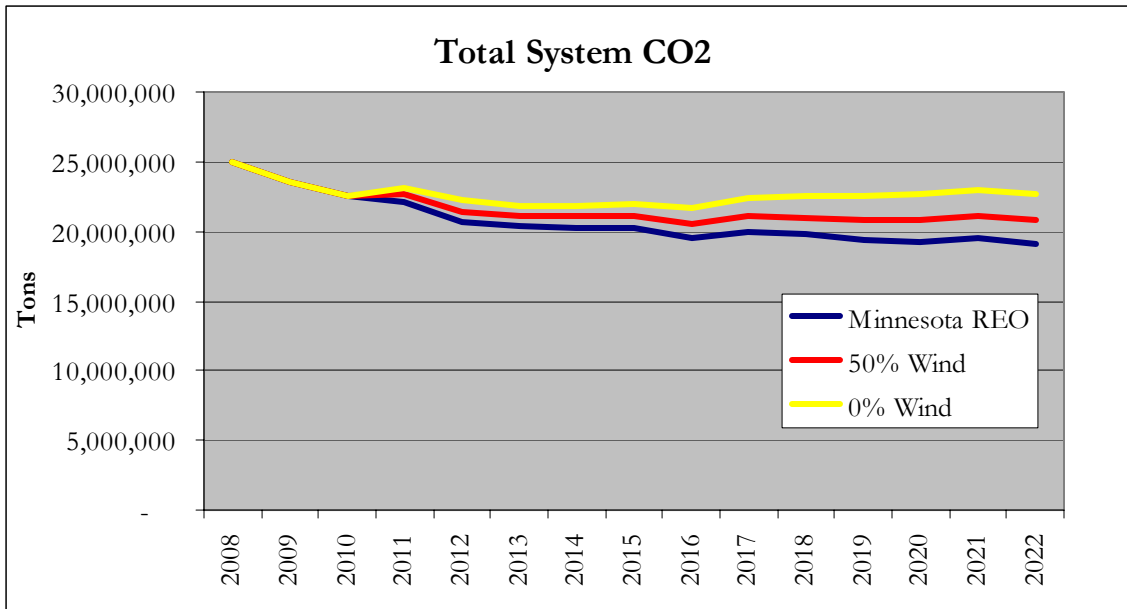
% Change From 100% Wind Level

	PTC Expiration		
	2015	2012	2009
100%	-	-	-
90%	-0.33%	-0.34%	-0.41%
80%	-0.62%	-0.63%	-0.79%
70%	-0.77%	-0.79%	-1.02%
60%	-0.92%	-0.95%	-1.26%
50%	-1.07%	-1.11%	-1.50%
40%	-1.14%	-1.19%	-1.66%
30%	-1.20%	-1.26%	-1.81%
20%	-1.16%	-1.23%	-1.85%
10%	-1.05%	-1.13%	-1.83%
0%	-0.99%	-1.08%	-1.86%



This analysis should provide the information that the Chamber is seeking on the impacts of adding wind to our Resource Plan to meet the RES. The RES legislation does provide for “off ramps” for a number of circumstances, including those where complying with the RES would result in unreasonable rates to our customers. While the results above do indicate cost increases for fully meeting the RES, they represent an analysis that assumes that the Company is an “island” and does not have access to the MISO market. Adding market impacts will change the dynamics of system dispatch and could increase the cost-effectiveness of wind. In any event, it is too early to determine based on this analysis that the RES would unreasonably increase rates. We will be monitoring this situation carefully as we move forward to add resources to meet our RES.

Although the wind adds cost to our resource plan, it also provides a valuable hedge by reducing natural gas consumption and exposure to future carbon regulations. The following charts illustrate wind’s impact on CO₂ emissions and natural gas consumption.



C. REASONABLE RATES

The Chamber emphasized that low rates need to be a key component to any Resource Plan. It stated that the resource selection process should be designed to ensure acquisition of the lowest-cost resources available, and questioned how much of the cost increases we projected over the planning period are due to meeting the renewable energy requirements versus the lowest-cost resources. It further recommended that the Commission “accept” the estimate of 3% to 4% annual cost increases shown in Appendix C of our December 2007 filing as “reasonable” and conclude that any annual increases higher than this be deemed “unreasonable.”

We appreciate the Chamber’s concern and agree with its emphasis on keeping rates as low as reasonably possible while meeting our obligations to produce electricity in an environmentally responsible manner. However, there are many factors that contribute to the determination of the reasonableness of rates. Our current cost estimates are based on assumptions of future conditions that may or may not materialize, and there are certainly future scenarios where costs could increase beyond what we’ve predicted and still be found reasonable by the Commission. Locking into a specific range at this time could prevent the Company and Commission from making appropriate policy determinations in the future.

We believe our Plan offers a reasonable balance of considerations and will result in the most appropriate portfolio of resources for meeting our customers’ growing needs. In the future, after assessment of the relevant facts at that time, the Commission will make the ultimate determination of reasonable costs and rates.

VII. NUCLEAR ENERGY

A. ENVIRONMENTAL EFFECTS OF POWER UPRATES

The Prairie Island Indian Community contends that the Company should be required to provide a substantive discussion of the environmental impacts of the Prairie Island uprate project as part of our Resource Planning process. The purpose of the Resource Plan is to indicate how the Company plans to meet

the energy needs of our customers over the next 15 years. We believe that the concerns of the Community and the level of detail contemplated are more appropriately addressed in the Certificate of Need proceedings before the Commission and the health and safety proceedings before the Nuclear Regulatory Commission.

The Certificate of Need application for the Prairie Island Extended Power Uprate (Docket E002/CN-08-509) was filed on May 16, 2008. Chapter 8 of the application contains the project environmental information required by Minn. R. Parts 7849.0310, 7849.0320 and 7849.0340 and discusses the environmental impacts of the proposed power uprate project. On July 15, 2008, the Commission accepted the application as substantially complete pending the filing and acceptance of additional information identified by the OES. On August 1, 2008, the Site Permit for the Prairie Island Extended Power Uprate project (Docket E002/GS-08-690) was filed. The Site Permit also addresses many of the environmental concerns expressed by the Community.

With respect to the environmental impacts associated with the processing of nuclear fuel (uranium), Minnesota statutes do not require assessment of the environmental impacts of carbon emissions from the mining process of uranium, coal or other raw materials associated with the fuel or construction of the proposed plant or alternatives. This issue has been raised elsewhere. In Sweden, Vattenfall (the Swedish Energy Utility) completed work to estimate the total CO₂ emissions from nuclear power. Vattenfall produces electricity via nuclear, hydro, coal, gas, solar cells, peat and wind energy resources and produced credited Environment Product Declarations for all of these processes. Vattenfall finds that, averaged over the entire lifecycle of their nuclear plants including uranium mining, milling, enrichment, plant construction, operating, decommissioning and waste disposal, the total amount of CO₂ emitted per kWh of electricity produced is 3.3 grams per kWh. In comparison, the lifecycle production from natural gas is 400 grams of CO₂ per kWh and 700 grams per kWh result from coal production.

Vattenfall determined that its nuclear plants emit less CO₂ than any of its other energy production mechanisms, including Hydro, Wind, Solar and Biomass, which all emit significantly less CO₂ than fossil fuel generation.

(<http://nuclearinfo.net/Nuclearpower/WebHomeGreenhouseEmissionsOfNuclearPower>)

B. NUCLEAR WASTE DISPOSAL

The Prairie Island Indian Community also contends that the Company should include a discussion of nuclear waste disposal in our Resource Plan. We are required by the Commission's Order dated August 10, 1992 in Docket No. E-002/CN-91-19 to file information regarding progress towards long-term permanent disposal of the spent fuel generated at the Monticello and Prairie Island Nuclear Generating Plants. This has been accomplished in various proceedings before the Commission including the Annual Nuclear Waste Management Report (last filed August 8, 2008)², the Monticello Spent Fuel Storage Need proceeding concluded in October 2006 and the current Prairie Island Need application for additional dry cask storage. Thus, the discussion of separate long-term disposal initiatives and strategies is addressed in these forums.

C. DRY CASK TRANSPORT

The Prairie Island Indian Community also commented that the Company should be required to supplement our filing to include details regarding the licensing process and other issues associated with the transportation of the dry casks containing nuclear waste. As we noted on Page 8-15 of our Plan, the application to the NRC to license the TN40s for transport was accepted in August 2007. We anticipate a decision in approximately twelve to fourteen months. The NRC has already approved a similarly designed cask, the TN68, for transport. The TN68 is a "sister" cask utilized for boiling water reactor spent fuel, while the TN40 is for spent fuel from pressurized water reactors.

Nuclear spent fuel is regularly transported in the United States. Over the course of 35 years, the nuclear energy industry has safely completed more than 3,000 shipments of used nuclear fuel covering 1.7 million miles, with no injuries, fatalities or environmental damage. This includes the shipment of 1,058 spent fuel assemblies from the Monticello Nuclear Generating Plant to General Electric's Morris facility in the 1980s. Transportation of spent fuel and the licensing of the containers to transport spent fuel are established processes and do not require further discussion in this Resource Plan proceeding.

² Because the Docket dates back to 1991, the Commission has not been including this information in edockets. The Commission is currently reviewing how best to make this information more readily available to the public.

D. HEALTH AND SAFETY ISSUES ASSOCIATED WITH NUCLEAR ENERGY

Both the Prairie Island Indian Community and MCEA provided comments regarding the safety and health impacts of the proposed power uprate projects. We agree that health and safety are important, essential considerations.

Before power uprates can be implemented the NRC must approve amendments to Monticello's and Prairie Island's operating licenses. NRC regulations define the information requirements to be provided in a license amendment application, including technical and environmental information. Prior to issuing the license amendments, the NRC must satisfy itself that the health and safety of the public will be protected. The Company will be filing an amended license application to uprate the Monticello plant with the NRC later this year. The NRC will not begin their detailed review of this application until they are satisfied that they have complete information and will not approve the amendment until we have demonstrated that the health and safety of the public is protected.

The Certificate of Need applications for both the Monticello and Prairie Island power uprates have been submitted to the Commission. Both applications have been determined complete and have been referred to an Administrative Law Judge for hearings. Additional information will be developed as necessary in response to issues identified as the cases progress through the process.

We believe that adequate review, documentation and approval of the environmental, safety and health impacts of the proposed power uprates at Monticello and Prairie Island are being developed in the project specific proceedings outside of the Resource Planning docket.

E. DRY CASK STORAGE

The MCEA comments that the proposed nuclear uprates will also create the need for additional storage of nuclear waste at the Monticello and Prairie Island Plants. It suggests that the proposed Prairie Island uprate effectively doubles the number of casks for that facility. As we discuss in our Certificate of Need application the 35 casks requested for additional dry cask storage at Prairie Island are not related to the proposed power uprate. The 35 additional dry storage casks requested will support 20 years of additional operation. It is estimated that Monticello could require up to three additional dry storage containers to support the power uprate, if DOE has not begun to remove spent fuel from the site by 2025.

VIII. MAPP

In our June comments we provided a discussion of our changing reserve margins as a result of our exit from the MAPP Generation Reserve Sharing Pool (“GRSP”) and our participation in the MPRSG. Since we filed our comments, the MPRSG disbanded as of May 1, 2009 in favor of a reserve sharing group that will be operated by MISO. MISO is currently conducting its Loss of Load Expectation Studies in order to determine the appropriate reserve margins for the 2009 planning year, beginning June 1, 2009. We are participating in the studies and at this time we expect that the reserve margins will be very similar to the 14.2% currently used by the MPRSG. We will continue to update the Commission as more information becomes available.

IX. RESPONSE TO EXCELSIOR ENERGY’S RESOURCE OPTION

Excelsior Energy suggests that we have failed to follow statutes and Commission rules by neglecting to include its Mesaba integrated gasification combined cycle (“IGCC”) plant in our preferred plan. It further argues that our plan is too dependent on natural gas as a future generating resource and thus fails to protect customers from potentially future high prices.

Excelsior’s characterization of our resource plan as relying solely on gas and wind is incorrect. As noted in December 2007 filing, our preferred plan includes resources fueled with wind, biomass, hydro, coal, nuclear and natural gas, a mix that is as diverse as any resource plan filed in Minnesota in recent years. What Excelsior terms as our “all eggs in one basket” approach is in fact a robust, cost-effective expansion plan that will result in an actual reduction in carbon dioxide emissions of 22% below 2005 levels by 2020.

The Commission has conducted extensive proceedings in which it considered Excelsior’s request for an Order for the Company to sign a PPA for output from its Mesaba IGCC project. In the first phase of the proceeding, the Commission determined that it would not be in the public interest to require the Company to sign the proposed contract (Order issued on August 30, 2007 in Docket. No. E-6472/M05-1993). Among other things, the Commission found that the proposed price was too high and that the contract terms unreasonably shifted risk onto the Company and our customers. In the second phase of the proceeding, the Commission declined to require the Company to

purchase 13% of its energy from the project, indicating that the project was not, nor was it likely to be, a least-cost resource (Order pending).

We believe that this thorough examination of Excelsior's claims fulfills our obligation to consider the Mesaba project as a future component of our resource plan. Our preferred plan meets all of our statutory and regulatory requirements at a lower cost and lower environmental impact than a plan that would include the Mesaba project. To the extent Excelsior has improvements to its proposal, it should bring those forward in the negotiations ordered in Phase I.

As a part of its comments, Excelsior has included a new analysis that purports to show that the Mesaba project is a lower cost option than natural gas combined cycle or wind/gas combinations. In addition to the fact that Excelsior has failed to provide the construction cost assumptions that support its analysis, it has provided an inappropriate head-to-head comparison of these resources as opposed to a system approach. In its cost comparison graph, Excelsior has forced each of the resources to operate at a 90% capacity factor, rather than allowing for economic dispatch. This analysis is of little use in determining which resource will operate at the lowest cost on our system.

Finally, Excelsior questions the continued decline of projected additional baseload need in our resource plans and suggests that by refusing to add coal-based resources, we are dangerously increasing natural gas capacity on our system. As we explained in our initial filing, the addition of wind to meet the RES supplies a great deal of energy on our system, which diminishes the future need for the type of 24 hour energy supplied by a traditional base load resources. This need further declines as a result of our participation in the MISO market, which provides access to low-cost energy during most of the off-peak hours. As a result, adding traditional baseload resources results in excess energy and increases the costs of our portfolio to our customers.

Although our preferred plan does show a marked increase in the percentage of capacity that will be fueled by natural gas on our system, an examination of our energy use as shown on page 7-6 of our December 2007 filing shows that over 85% of our energy will still come from other fuels in 2020. The diversity of our fuel mix is one of the strongest components of our resource portfolio, which will allow us to maintain resource flexibility and reasonable costs into the future.

X. NORTHERN FLOOD AGREEMENT MONITORING

The MCEA suggests in their comments that the Company should not enter into any further negotiations with Manitoba Hydro absent a showing that Manitoba Hydro is “making progressive compliance with its obligations under the Northern Flood Agreement.” The Commission thoroughly reviewed and examined this issue in our last resource plan. That review evidenced a complex relationship between Manitoba Hydro, Canadian governmental entities and the Cree Nations. It also reflected diversity of opinion among the separate Cree Nations and continuing dialogue and efforts between Manitoba Hydro and the Cree Nations. We believe the Commission’s consideration of these issues in our last resource plan was sufficient and that no further action is necessary at this time. (Pages 12 – 14, Docket No. E-002/RP-04-1752, July 28, 2006 Order).

CONCLUSION

We appreciate the comments presented by parties regarding our 2007 Resource Plan. Changes in the economy and in energy policy will continue to have an impact on Resource Planning. The relatively small shifts in our preferred plan in response to sizeable changes in our load forecast as well as capital and fuel costs is a testament to the robustness of the preferred plan that was submitted in December. To that end, we respectfully request that the Commission approve our updated Action Plan as described below:

- *Significantly increase DSM goals to meet legislative requirements by striving to achieve a 1.15% DSM goal in 2010, 1.2% in 2011 and 1.3% in 2012.*
- *Install sufficient renewables to meet the RES.*
- *Obtain NRC and Minnesota approvals for additional dry cask storage and power uprates at Prairie Island and Monticello.*
- *Pursue capacity expansion at our Sherco coal-fired units.*
- *Continue to pursue repowering at Units 3 and 4 of our Black Dog Plant .*
- *Initiate a new proceeding for approval of a 375 MW intermediate and 350 MW peaking contract with Manitoba Hydro beginning in 2015.*
- *Initiate a proceeding for 160 MW of peaking resources in 2014.*
- *Continue and support efforts to ensure that sufficient transmission resources are available to get needed generation to load.*

As always, we will continue to carefully monitor developments. To the extent that we need to respond to a development in a way not addressed by this Resource Plan, we will file with the Commission under Minn. Rule 7543.0500, Subd.5 for a notice of changed circumstance. Careful monitoring and prompt action will be required to ensure we successfully manage resources during this period of continuing market development and change.

Overall, we believe it is important that the Commission approve a Resource Plan that can readily respond to changing conditions. While we believe it is important to determine within this Resource Plan the size, type, and timing of required new resources, we also believe that our customers will benefit from allowing other, more specific decisions to unfold within the context of the resource selection process.

The Company is committed to meeting our customers' needs in a low-cost, reliable, environmentally sound manner. We will comply with all applicable laws and requirements when meeting these needs. We are prepared to continue with the development of specific resource options for the Commission's consideration, and will present further proposals to help ensure the successful implementation of preferred resources. We look forward to continued discussion in this proceeding and the Commission's consideration of these issues.

Dated: September 5, 2008

Respectfully Submitted by:
Northern States Power Company

/s/

JAMES ALDERS
DIRECTOR, REGULATORY ADMINISTRATION

Attachment C Schedule 1
2007 IRP Reply Comments_9-5-08
CERTIFICATE OF SERVICE

I, Nancy A. Haley, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States Mail at Minneapolis, Minnesota

xx electronic filing

DOCKET NO. E002/RP-07-1572

Dated this 5th day of September 2008

/s/

Nancy A. Haley

Attachment C Schedule 1

In the Matter of Xcel Energy's 2007-2022 Reply Comments_9-5-08
Integrated Resource Plan

E002/RP-07-1572

9-4-2008

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ADP Application

Nuclear Projects

PU-10-_____

April 19, 2010

Attachment C Schedule 1

2007 IRP Reply Comments_9-5-08

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