



414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

June 30, 2011

Illona A. Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard, Dept. 408
Bismarck, ND 58505

RECEIVED

JUL 05 2011

PUBLIC SERVICE COMMISSION

RE: NORTHERN STATES POWER COMPANY
ANNUAL TEN-YEAR PLAN

Dear Ms. Jeffcoat-Sacco:

In accordance with Chapter 49-22 of the North Dakota Century Code, Northern States Power Company, a Minnesota corporation, hereby submits 10 copies of its Annual Ten-Year Plan for Major Generation and Transmission Facilities in the state of North Dakota. The information contained in the report complies with the rules and regulations of the North Dakota Public Service Commission.

Notice of the filing has been given to each state agency and officer entitled to notice as designated in section 69-06-05. A service list is attached.

If you would like additional copies of this filing, or if you have questions regarding information contained therein, please feel free to contact Dave Sederquist at (701) 241-8632.

SINCERELY,

/s/

AMBER HEDLUND
REGULATORY ADMINISTRATOR

ENCLOSURES
CC: SERVICE LIST (WITHOUT ENCLOSURES)

CERTIFICATE OF SERVICE

I, Lindsey Didion, hereby certify that I have this day served notice of the foregoing document on the attached list of persons by delivery by hand or by causing to be placed in the U.S. mail at Minneapolis, Minnesota.

TEN-YEAR PLAN FOR MAJOR GENERATION AND TRANSMISSION FACILITIES IN THE STATE OF NORTH DAKOTA

Dated this 30th day of June 2011

/s/

Lindsey Didion

Northern States Power Company d/b/a Xcel Energy
2011 North Dakota Ten-Year Plan
Service List – Notice of Filing

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State Historical Society
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State Water Commission
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Bismarck, ND 58502

North Dakota Parks and Recreation Department
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Job Service of North Dakota
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Bismarck, ND 58502

Soil Conservation Committee
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Bismarck, ND 58505

Aeronautics Commission
PO Box 5020
Bismarck, ND 58502

North Dakota Department of Transportation
608 East Boulevard Avenue
Bismarck, ND 58505-0700

**TEN-YEAR PLAN FOR
MAJOR GENERATION AND
TRANSMISSION FACILITIES**

TO THE

**NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

**SUBMITTED BY
NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION
JUNE 2011**



**Northern States Power Company
North Dakota Ten-Year Plan 2011
Table of Contents**

Section A: Existing Energy Conversion Facilities	2
Section B:	2
Proposed Energy Conversion Facilities - Next Five Years	
Nuclear Resources	3
Fossil Fuel Resources	5
Hydro Resources	6
Renewable Resources	8
Section C:	9
Proposed Energy Conversion Facilities - Next Ten Years	
Section D: Existing Electric Transmission Facilities	9
Section E: Existing Pipeline Facilities	11
Section F:	11
Proposed Electric Transmission Facilities - Next Five Years	
Section G: Proposed Pipeline Facilities - Next Five Years	16
Section H: Proposed Electric Transmission and Pipeline Facilities - Next Ten Years	17
Section I: Regional Coordination	18
Section J: Environmental Information	22
Section K: Projected Demand for Service	22
Appendix A:	i
Schedule of Advance Determination of Prudence Filings	
Appendix B:	iii
Report on the Effect of Wind Generation on Baseload Plants	

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

IN THE MATTER OF THE 2011 TEN-YEAR
PLAN OF NORTHERN STATES POWER
COMPANY, A MINNESOTA CORPORATION

TEN-YEAR PLAN

INTRODUCTION

Northern States Power Company, a Minnesota corporation operating in North Dakota (“Xcel Energy”, “NSPM” or the “Company”), is pleased to submit our annual Ten-Year Plan to the North Dakota Public Service Commission (the “Commission”) in compliance with Section 49-22-04 of the North Dakota Century Code. NSPM has service territory in three upper Midwest states including North Dakota. Northern State Power Company, a Wisconsin corporation (“NSPW”), has service territory in Wisconsin and Michigan. The Company presently serves approximately 89,000 retail electric customers in and around Fargo, Grand Forks, and Minot, North Dakota. Xcel Energy owns just over 250 miles of transmission lines and 14 substations in North Dakota.

This filing contains an expanded Ten-Year Plan submitted in compliance with the Settlement in Case No. PU-07-776 and Commission Rules, including:

- An expanded version of our description of the major generation and transmission initiatives we plan to pursue over the next 5 and 10 years to serve our customers in North Dakota, South Dakota, Minnesota, Wisconsin and Michigan; and
- A schedule of anticipated future applications for Advance Determination of Prudence (“ADP”).

SECTION A: EXISTING ENERGY CONVERSION FACILITIES

While the Company does not currently own energy conversion facilities in the State of North Dakota, the Company does have power purchase agreements and exchanges with various utilities for power produced in North Dakota. Minnkota Power Cooperative, Inc. provides the Company with 100 MW each summer season from its rights in the Coyote #1 coal fired steam generating unit located in Beulah, North Dakota. Acciona Wind Energy USA provides the Company with 12 MW of wind energy from turbines located near Velva, North Dakota. Additionally, the Company has a power exchange arrangement known as the “Stanton Displacement Agreement” in which 188 MW are supplied from Great River Energy’s Stanton Unit, located in the vicinity of Stanton, North Dakota, for the Company’s North Dakota loads.

SECTION B: PROPOSED ENERGY CONVERSION FACILITIES - NEXT FIVE YEARS

NSPM and NSPW operate their upper Midwest generation resources on a five-state integrated system basis (North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan). We identify our resource needs in our Resource Plan. We filed our 2011-2025 Resource Plan with all five states on August 1, 2010. Our Resource Plan included planning scenarios based on North Dakota requirements, particularly with respect to how externalities are modeled.

We will most likely propose to continue to fulfill our future electric generating resource needs through multiple resource acquisition processes including competitive bidding, Company ownership, power purchase agreements, and energy efficiency. This multipronged and flexible approach to resource acquisitions allows us to consider multiple technologies and locations.

In this section, we update the Commission on generation projects currently in progress, and provide a summary of the generation projects we are considering or undertaking in the next five years across our five-state integrated system. We believe these projects, considered as a whole with our existing generation assets, result in a robust and diverse portfolio of resources that will provide our customers with cost-effective and reliable service over the long-term.

NUCLEAR RESOURCES

On April 19, 2010 we filed an application for an ADP for two Prairie Island Plant projects (Case No. PU-10-127), new Unit 2 steam generators and Units 1 and 2 Extended Power Uprates. As part of that filing, we also provided an update on the Monticello Nuclear Plant uprate project. Below we provide a summary of our discussions on both plants.

Monticello: In November 2008, we filed an application with the Federal Nuclear Regulatory Commission (“NRC”) to amend the operating license at our Monticello Nuclear Generating Station to allow operation at an increased thermal power. This will allow us to increase the generating capacity by approximately 71 MW to approximately 671 MW. The NRC Staff has indicated that 16 of 17 divisions within the NRC have completed their reviews. Staff is waiting for further work from the Boiling Water Reactor Owners Group (“BWROG”) regarding the hydraulic margins of the pumps that supply cooling water to the reactor in the unlikely event of an emergency. The BWROG’s report is due in September 2011. If the NRC Staff concludes that the BWROG report demonstrates adequate hydraulic margins, we will work with the NRC Staff to complete the license application as expeditiously as

possible. If the NRC Staff can not conclude that report clearly shows adequate hydraulic margins, further review may be necessary.

The majority of the plant modifications supporting the extended power uprate were made in the Spring of 2011. The last few components will be installed during the Fall 2011 mid-cycle outage. This will allow the plant to generate at the higher MW level once we receive final approval from the NRC.

Prairie Island: On December 18, 2008, the Minnesota Public Utilities Commission (“MPUC”) issued two Certificates of Need (“CON”) for our Prairie Island nuclear generating plant. Approval of MPUC Docket No. E002/CN-08-509 provided for an extended power uprate of 164 MW at Prairie Island. Approval of MPUC Docket No. E002/CN-08-510 allows for additional dry cask spent fuel storage to support extending operation of the two Prairie Island units through 2033/2034.

On June 27, 2011, the NRC approved our request to extend the operating licenses for Units 1 and 2. We anticipate filing for the license amendments to implement the extended power uprates at Prairie Island in late 2011 or early 2012, and anticipate a decision from the NRC approximately two years thereafter.

FOSSIL FUEL RESOURCES

Sherco Upgrades: We are currently proceeding with an approximate 21 MW¹ upgrade at Unit 3 of our Sherburne County (“Sherco”) coal-fired generating facility. We expect the upgrade to be completed in December 2011. We submitted plans to the MPUC to install a mercury control system for Units 1 and 2 in the 2013 to 2014 time frame. Based on expected new Environmental Protection Agency rules, we anticipate that the system we install may also be required to control for other hazardous air pollutants. We are still working on the optimization of the mercury control system for Unit 3. We plan to complete this testing in the fall of 2011.

Black Dog Repowering: Black Dog Units 3 and 4 were installed in 1955 and 1960 respectively and are currently near the end of their economic and engineering life. On March 15, 2011, the Company filed a CON application with the MPUC for the repowering of Black Dog Units 3 and 4 from an existing 253 MW coal-fired generating facility to about 700 MW of natural gas-fired combined cycle generation (MPUC Docket No. E002/CN-11-184). As part of the CON process, the Company has requested competitive proposals which are due July 1, 2011. If the Company proposal is deemed most cost effective, we anticipate the Repowering Project to be completed and the new units placed in commercial operation in January 2016. We plan to file for an ADP for this project or an alternative project selected through the competitive bidding process in late 2011.

¹ This unit is co-owned by Southern Minnesota Municipal Power Agency (“SMMPA”). The Company’s share of this additional generation is 13 MW.

HYDRO RESOURCES

Manitoba Hydro: We have negotiated an extension of our existing power purchase arrangement (“PPA”) with Manitoba Hydro that will be implemented through three interlocking agreements as summarized below.

- **375/325 MW System Power Agreement:** Under this agreement, the Company will purchase 375 MW of Midwest Independent System Operator (“MISO”) qualified capacity during the six summer season months (May – October) and 325 MW of MISO qualified capacity during the six winter season months (November – April). The agreement consists of three products: 1) “Fixed Price Energy;” 2) “Additional Energy;” and 3) “Firm LD Energy.” With Fixed Price Energy, we must take and pay for energy Monday through Friday from 7 am through 10 pm (“5 by 16 Fixed Price Energy”) during the summer months and Monday through Friday from 9 am through 8 pm (“5 by 12 Fixed Price Energy”) during the winter months. “Additional Energy” and “Firm LD Energy” are products designed to maximize the use of the transmission system and can be sold at Manitoba Hydro’s option. The 375/325 System Power Agreement term is May 1, 2015 through April 15, 2025.
- **125 MW System Power Agreement:** The term of this agreement will be May 1, 2021 through April 30, 2025, assuming Manitoba Hydro has proceeded with a contract to construct its next major hydroelectric project. Under this agreement, we will purchase an additional 125 MW of (year-round) system capacity. This agreement will provide the same energy products as described for the 375/325 MW System Power Agreement. The terms and conditions are

consistent and substantially the same as the 375 MW/325 MW System Power Agreement and the net effect will increase our system purchase to 500 MW (Summer) and 450 MW (Winter).

If by May 1, 2018, Manitoba Hydro has not committed to proceed with a new major hydroelectric project, this contract will terminate, unless Manitoba Hydro waives this condition, but the 375/325 MW Agreement will remain in place.

- 350 MW Diversity Agreement: This Agreement allows the parties to extend the 350 MW capacity exchange through April 30, 2025. To accomplish this, the parties will terminate the existing diversity exchange agreements as of May 1, 2015 and replace them with a single agreement. Similar to the existing diversity exchange agreements, the parties will exchange 350 MW of qualifying capacity on a seasonal basis at no cost to the other party. During the summer, Manitoba Hydro must offer energy to the Company seven days per week during the four MISO peak hours to ensure MISO approval of the capacity. Beyond this obligation, we are not required to purchase energy.

Taken together, the Manitoba Hydro transaction provides us with significant capacity and energy at times that maximize the value to the Company. The agreements utilize an existing transmission path, which can support as much as 892 MW per hour of transfer. However, because of the energy profile of these contracts, there will be many hours of the year when substantially less power is flowing over the transmission path. The contracts collectively provide Manitoba Hydro the option to sell additional “option energy,” from a predominantly hydro system, to the Company at an advantageous price. The Agreements were approved by the MPUC on May 26, 2011

(Docket No. E-002/M-10-633). The Company is in the process of preparing an ADP filing for this transaction that will be filed with the Commission in the near future.

RENEWABLE RESOURCES

North Dakota Wind Commitment: The Company remains committed to construct or purchase wind resources located in North Dakota. As the Commission is aware, the Merricourt Wind Project was cancelled due to unresolved environmental concerns raised by the U.S. Fish and Wildlife Service. The long stop date for the contract was March 31, 2011. Because environmental and permitting issues were not resolved by that date, we believed it was appropriate to exercise our termination rights on the long stop date. The Company will report to the Commission on progress towards achieving our objective to add wind resources in North Dakota in the months ahead.

Nobles Wind Project: The Nobles Wind Project is a 201 MW wind energy generation facility consisting of 134 GE 1.5 MW wind turbines located in Nobles County on the Buffalo Ridge in Minnesota. The Nobles Wind Project began commercial operation in December 2010.

Community Based Energy Development (“CBED”): We currently have approximately 210 MW of community-based wind on the system that qualifies for the North Dakota Renewable Energy Objectives and Standards and another approximate 116 MW under contract and scheduled for construction within the next couple of years. With the exception of the Goodhue Wind Project, no project is large enough to trigger the Settlement threshold for requiring an ADP application. If the Goodhue Project proceeds, we will file for an ADP.

Prairie Rose Wind Project: We solicited additional wind projects through a Request for Proposal (“RFP”) issued in September 2010. As a result of that solicitation, we have completed negotiations and signed a PPA for the purchase of 200 MW from the Prairie Rose Wind Project that will connect to the Angus Anson substation in SE South Dakota. We anticipate filing an ADP for this project later in the year.

SECTION C. PROPOSED ENERGY CONVERSION FACILITIES - NEXT TEN YEARS

At this time, our plans for additional generation facilities in the State of North Dakota over the next ten years involve wind energy conversion systems. The Company is committed to acquiring 200 MW of wind power in North Dakota.

SECTION D. EXISTING ELECTRIC TRANSMISSION FACILITIES

The Company’s existing electric transmission line facilities in North Dakota are listed below. We have no plans to retire any electric transmission facilities in North Dakota within the next ten years.

Table 1. NSP North Dakota Transmission Lines

State	Description	Functional Unit	Voltage	Line Miles
<u>230 kV Lines</u>				
ND	Maple River (Minnkota)	0910	230 kV	3.60
ND	Maple River (Minnkota)	0911	230 kV	8.07
ND	Drayton (Minnkota)-Letellier	0912	230 kV	28.34
ND	Sheyenne-Fargo	0915	230 kV	4.17
ND	Prairie (Minnkota)-Grand Forks	0916	230 kV	6.60
ND	Manitoba Hydro Inter (Glenboro)	0920	230 kV	56.20
Total 230 kV				106.98
<u>115 kV Lines</u>				
ND	Maple River-Sheyenne	0839	115 kV	11.61
ND	Souris-Neal	0850	115 kV	24.99
ND	Mallard-Souris	0860	115 kV	5.22
ND	Cass County-Sheyenne	0866	115 kV	3.54
ND	Prairie-Nordic1	5510	115 kV	2.00
ND	Prairie-Nordic2	5511	115 kV	1.98
Total 115 kV				49.34
<u>69 kV Lines</u>				
ND	Minnkota-Prairie	0733	69 kV	46.3
ND	Prairie-Grand Forks	0746	69 kV	6.4
ND	South-Hatton	0768	69 kV	28.96
ND	Prairie-Minnkota	0772	69 kV	13.26
ND	Elk Valley-Larimore	0776	69 kV	1.75
ND	Grand Forks (WAPA)-Prairie	0786	69 kV	7.72
Total 69 kV				100.51

SECTION E. EXISTING PIPELINE FACILITIES

The Company operates an 11.9-mile intrastate natural gas pipeline facility in the State of North Dakota, from an interconnection with Williston Basin Interstate Pipeline Company near Mapleton, North Dakota, to the Company's gas distribution system in Fargo. The Commission granted a Certificate of Public Convenience and Necessity and Corridor Certificate for this facility in Case No. PU-400-89-426. The Company has no plans to retire any intrastate natural gas pipeline facilities in North Dakota within the next ten years.

SECTION F. PROPOSED ELECTRIC TRANSMISSION FACILITIES - NEXT FIVE YEARS

In this section, we provide a brief description of significant transmission developments planned by the Company in North Dakota and elsewhere in the NSPM and NSPW service territories.

CapX2020: A group of investor-owned, cooperative and municipal utilities in Minnesota, eastern North Dakota, eastern South Dakota, and western Wisconsin ("CapX2020 Utilities"), completed a high-level visionary study looking at the bulk transmission needs in their combined market areas over the next 15 years. This analysis, known as the CapX2020 Vision Study, identified, among other projects, the need for a 345 kV line from western North Dakota to the Twin Cities, passing through the Fargo area to serve growing energy needs in the Red River Valley.

From this Vision Study the CapX2020 Utilities developed more specific proposals for the first group of new high voltage lines needed, referred to as Group 1 projects. The Group 1 projects include three 345 kV projects, and one 230 kV project. The first of these facilities is proposed to be placed in service in 2011, and the other facilities will be placed into service over the following years with an ultimate completion date of

2015. The approximate lengths and general location of the proposed 345 kV and 230 kV lines are as follows:

- A 250 mile, 345 kilovolt line between Fargo, North Dakota, and Alexandria, St. Cloud and Monticello, Minnesota (“Fargo Project”);
- A 230 mile, 345 kilovolt line between Brookings, South Dakota, and the southeast Twin Cities, plus a related 30 mile, 345 kilovolt line between Marshall, Minnesota, and Granite Falls, Minnesota (“Brookings Project”);
- A 150 mile, 345 kilovolt line between the southeast Twin Cities, Rochester, Minnesota, and La Crosse, Wisconsin (“La Crosse Project”); and
- A 68 mile, 230 kilovolt line between Bemidji and Grand Rapids, Minnesota (“Bemidji Project”).

Xcel Energy and Great River Energy, on behalf of the other participating CapX2020 Utilities, filed a CON application for the three 345 kV projects (Brookings, Fargo and La Crosse Projects) with the MPUC on August 16, 2007. The MPUC has approved CONs for all three 345 kV projects.

With regard to the Fargo Project, a route permit was granted by the MPUC for the Monticello to St. Cloud segment in July of 2010, and construction is expected to be complete by the end of 2011. In October 2009, a Route Permit for the St. Cloud to Fargo segment was filed in Minnesota with final selection of the route approved in June 2011. In North Dakota, the Certificate of Public Convenience and Necessity was issued in January of 2011. The Certificate of Corridor Compatibility application was filed in December 2010, and the Route Permit application is expected to be filed in late summer 2011.

With regard to the Brookings Project, a portion of that project is proposed to be constructed in South Dakota. Xcel Energy and Great River Energy, on behalf of the other owners of the Brookings Project filed a Route Permit application with the MPUC on December 29, 2008 (Docket No. ET-2/TL-08-1474). The Minnesota Commission issued the final Route Permit for the Minnesota portion of this Project in May 2011 and the South Dakota Commission granted the Facility Permit for the South Dakota portion of the Brookings Project in June 2011. This project is currently in the process of being approved through the MISO Multivalued Project (“MVP”) process. Conditional approval was granted in June 2011 and final approval is expected in December 2011. In North Dakota, an ADP was approved for the CAPX group of projects, and the order required Xcel Energy to make a filing providing additional information on the resolution of cost allocation issues relevant to the Brookings Project, including the impact on North Dakota. We filed this Settlement compliance filing with the Commission in April 2011, in which we provided evidence of continued prudence of the Brookings project. A hearing has been scheduled for July 2011.

Otter Tail Power Company, Minnkota Power Cooperative and Minnesota Power, on behalf of themselves and Great River Energy and Xcel Energy, filed a CON application with the MPUC for a 70 mile 230 kV line between the Boswell Substation near Cohasset, MN to the Wilton Substation near Bemidji, known as the Bemidji line. The project includes expanding the substation near Cass Lake, MN, with a new 230/115 kV transformer. The CON was filed in March 2008, and an application for a Route Permit was filed in June 2008. The MPUC issued a CON in July 2009 and a Route Permit in November of 2010. Tree clearing is currently underway along the route with construction expected to start during the summer of 2011. The current schedule for the Bemidji Project shows a projected late 2012 in-service date. Once

completed, this project will help support the increasing loads in the Red River Valley region.

With regard to the La Crosse Project, a Route Permit application was filed with the MPUC in January 2010. An application for a Certificate of Public Convenience and Necessity was filed with the Wisconsin Public Service Commission in January 2011.

The CapX2020 Group 1 projects listed above will benefit North Dakota by improving transmission infrastructure and reliability, alleviating existing delivery constraints, and expanding the transmission capability to allow expanded generation investment, including wind generation, in North Dakota.

More information about the CapX2020 Initiative is available at www.capx2020.com.

Southwest Twin Cities 115 kV Conversion Projects: In 2006, the Company and Great River Energy completed a study (*Southwest Metro 115 kV Transmission Development Study*) of the load serving needs in the regions of Scott, Carver and Hennepin Counties to the west side of the Twin Cities metro area. The conclusions reached in that study confirmed the results of previous studies that showed that portions of the existing transmission system were not capable of supporting the growing system loads over the next 5 to 10 years. The study also identified three distinct load-serving areas within the larger study area and identified solutions for meeting the load serving needs of each of these transmission areas. Since that study was completed, the Company has conducted further evaluations to refine the timing for proposing solutions to the transmission system.

The first of these proposed solutions for the sub-areas is in the Glencoe – Waconia area and is the subject of a current CON request before the MPUC². This CON request was filed on November 30, 2010, and calls for the construction of two miles of new 69 kV transmission line³, six miles of new 115 kV transmission line, and to upgrade approximately 20 miles of 69 kV transmission line to 115 kV capacity near the cities of Glencoe, Norwood Young America and Waconia along with the construction of a new substation and certain substation modifications. The project is located in Carver and McLeod counties of Minnesota.

The second of these projects requiring a CON is in or near the cities of Chanhassen, Shorewood, Excelsior, Deephaven, Greenwood, Minnetonka, and Eden Prairie, MN⁴. This project calls for the upgrade of the Bluff Creek – Westgate 69 kV transmission line to 115 kV capacity. This entails upgrading approximately 14 miles of 69 kV transmission line to 115 kV capacity as well as modifications of two substations. The Company has started the CON process for this project by filing with the MPUC a proposed notice plan (April 19, 2011) and an exemption request (June 17, 2011).

The last of these projects still being finalized is the upgrade of 69 kV transmission lines to 115 kV capacity in or near the City of Chaska. This project will also include the construction of some new 115 kV transmission line. The CON filing process for this project will begin later in 2011.

Greater Rochester Area Transmission Project: This project, also known as the

² In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, and the City of Glencoe for a Certificate of Need for 115 kV Transmission Line Upgrades to the Glencoe – Waconia 69 kV System, Docket No. E002/CN-09-1390, November 30, 2010.

³ Note that this section will be built to double circuit standards to accommodate additional 115 kV facilities needed for the third phase of development described below.

⁴ In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for a Certificate of Need for the Bluff Creek – Westgate Transmission Line Upgrade from 69 kV to 115 kV capacity, Docket No. E002/CN-11-332.

Pleasant Valley area projects, is a proposal to construct two 161 kV lines in the greater Rochester, MN area:

- Pleasant Valley to Byron substation (18 miles)
- Byron to West Side Energy Center (10 miles), this will complete the existing double circuit line between the Byron to Cascade Creek substations. Southern Minnesota Municipal Power Agency (“SMMPA”) is responsible for building this line.

There are a number of wind projects proposed in this area and at various stages within the MISO Interconnection study process. The MISO studies for Xcel Energy’s Grand Meadow project and the Wapsipinicon Wind farm determined that interconnecting these projects would cause transmission system constraints and would require the construction of the Pleasant Valley-Byron 161 kV line. Until this new upgrade is constructed, the wind projects are sometimes limited in the amount of power they can deliver to the system.

Xcel Energy submitted the CON and Route Permit filings with the MPUC in December of 2009 for the Pleasant Valley to Byron 161 kV line. The MPUC issued the CON and Route Permit in March of 2011. Right of way acquisition is nearing completion and construction is expected to begin in the fall of 2011 with an expected in-service date of spring 2012.

SECTION G: PROPOSED PIPELINE FACILITIES - NEXT FIVE YEARS

At this time we do not have plans to construct any new intrastate natural gas pipeline transmission facilities in North Dakota within the next five years.

SECTION H: PROPOSED ELECTRIC TRANSMISSION AND PIPELINE FACILITIES - NEXT TEN YEARS

Xcel Energy is currently involved in a large regional study with MISO, the MVP, to determine large regional transmission build outs to increase the reliability of the overall transmission system. These projects will be cost shared across the entire MISO footprint. These projects are to be qualified based on increased reliability, economic benefits, or address one or more of the states' renewable requirements.

The CapX2020 Brookings County project is being considered in this study process. In addition there are several lines that are being proposed that, if approved, Xcel Energy would have an ownership stake in. One of these lines would be the proposed Big Stone-Brookings County 345 kV line which is expected to provide outlet capabilities for renewable projects.

In addition to the MISO MVP process, Xcel Energy participates in transmission planning with a larger group of utilities called the Minnesota Transmission Owners ("MTO"). The MTO consists of all of the investor-owned, cooperative and municipal utilities that own transmission facilities 100 kV and above in Minnesota. Several MTO members (e.g., the Company, Great River Energy, Otter Tail Power, etc.) also own significant transmission facilities in North Dakota. These utilities are required by Minnesota law to file a biennial transmission plan with the MPUC by November 1 of every odd-numbered year, and formed the MTO to develop and submit a unified plan. The MTO has commissioned a number of studies focused on meeting renewable energy objectives and requirements and other generation and load serving needs through 2025. The MTO group also performs an annual 10-year assessment of the member utility system for compliance with the North American Electric Reliability Corporation ("NERC") Transmission Planning ("TPL") standards.

The MTO utilities also coordinate their planning with the CapX planning process and the MISO Midwest Transmission Expansion Plan (“MTEP”) process. These are comprehensive studies encompassing the impacts and needs over more than just Minnesota. These MTO studies are available at the MTO website at www.minnelectrictrans.com.

SECTION I: REGIONAL COORDINATION

All major transmission planning performed by Xcel Energy is now coordinated through MISO on a regional basis. MISO issues an annual transmission expansion plan known as MTEP after coordinated planning and stakeholder review.

As a result of complying with the FERC Order No. 890 rules, MISO has also implemented Sub-Regional Planning Meetings as part of their annual MTEP development process. The Company participates in the Western Region meetings. These Sub-Regional Planning meetings provide forums for stakeholder input and coordination of plans and we actively participate in each one. This joint planning is intended to maximize use of existing facilities and minimize the amount of new facilities

Another example of coordination by the utilities is the formalization of the MTO organization. In addition to the Minnesota biennial transmission planning work of the MTO, the MTO utilities also coordinate their transmission planning activities with the CapX2020 planning processes, and MISO’s MTEP process.

The MTO also coordinated and performed two major transmission studies. The Dispersed Renewable Generation (“DRG”) Transmission Study investigated the potential to install 600 MW of dispersed renewable generation in and around

Minnesota with minimal impacts to the transmission system. The other study was a series of studies under the heading of Renewable Energy Standard transmission studies that investigated the short and long-range transmission requirements in Minnesota and North and South Dakota for the MTO utilities to meet renewable energy objectives and standards.

The results of the MTO DRG Transmission study found that the lower and higher voltage transmission grid is essentially constrained in Minnesota when viewed in aggregate statewide, and more transmission is needed to meet renewable energy objectives and standards.

Xcel Energy is also actively supporting the Upper Midwest Transmission Development Initiative (“UMTDI”), formed in September 2008 by the Governors of North Dakota, South Dakota, Iowa, Minnesota and Wisconsin.

An executive committee made up of a representative of the Governor’s office from each state, and a regulatory commission from each state submitted an Executive Committee Final Report in September 2010. The report identified six renewable transmission corridors for potential primary transmission development, identified regional renewable energy zones most likely to support substantial wind development, and developed a set of cost allocation principles as a foundation for ongoing cost allocation discussions. The UMTDI will continue to focus on cost allocation in future planning endeavors.

Xcel Energy is also involved with the MISO led Regional Generation Outlet Study (“RGOS”) whose goal is to identify mutually beneficial bulk transmission lines that would facilitate the compliance with all state and possible national renewable energy

standards for states in the MISO footprint. These include the states from the UMTDI group along with states further east that exist in the MISO footprint. Study work began in 2008 and is now part of the MISO MVP study. The MVP study process will provide justification for cost allocation amongst MISO stakeholders from a list of candidate MVPs (CMVPs) previously identified in the RGOS, MTEP and other MISO studies.

The Company is also participating in the Strategic Midwest Area Renewable Transmission (“SMART”) Study that was commissioned in August of 2009. The SMART study’s goal is to develop a 20-year transmission plan that ensures reliable electricity transport, provides an efficient transmission system to integrate new generators and foster efficient markets, minimizes environmental impacts, and supports state and national energy policies.

Phase One of the study identified future transmission needs in the upper Midwest to support renewable energy development and to transport that energy to load centers. Study participants evaluated various transmission alternatives designed to support the integration of significant new wind generation within the study area, including North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Illinois, Indiana, Michigan and Ohio.

The study’s Phase One results recommend three alternatives for further study based on a rigorous reliability assessment and stakeholder input: (1) a 765 kV transmission solution; (2) a 765 kV and limited direct current transmission solution; and (3) a combined 345 kV and 765 kV transmission solution.

The study's Phase Two further investigated the economic benefits of alternatives (1) and (3) and was completed in October of 2010. Alternative (2) was eliminated due to its similarity to alternative (1). The economic analysis was performed with four separate economic cases: Base Case Wind, High Gas Futures, Low Carbon Future, and Low Wind Future.

The Phase Two results indicate there are no meaningful economic differences between alternatives (1) and (3) in the 2029 time frame.

The Phase One and Two reports can be downloaded at www.smartstudy.biz.

Finally, the Company is participating in the Eastern Interconnection Planning Collaborative ("EIPC"). EIPC is an effort to involve the entire Eastern Interconnection planning authorities to determine the effects of various policy options determined to be of interest by state, provincial and federal policy makers. EIPC was commissioned by the Department of Energy ("DOE") and includes State and Federal policy makers, Consumer and environmental interests, transmission planning authorities and other energy market participants. The funding opportunity from the DOE has two parts, Module A and Module B. Module A allows the eastern 40 states to collaborate on assessing existing transmission infrastructure and conduct planning scenarios to benefit the entire eastern United States. Module B allows energy leaders in each of the 40 eastern states to gather as a single entity to collaborate on transmission planning in the entire Eastern Interconnection. The study work began in early 2010.

SECTION J: ENVIRONMENTAL INFORMATION

Specific environmental information will be provided to the Commission in future regulatory filings when specific facilities are identified for construction.

SECTION K: PROJECTED DEMAND FOR SERVICE

The North Dakota portion of the NSP System 25-year historical native energy requirements and non-coincident peak demand are shown in Table 2. Xcel Energy produces long-range “median” system forecasts of native energy requirements, summer peak, and winter peak demand. For planning purposes, the Company also develops a bandwidth to supplement the “median” forecasts. These scenarios are intended to describe uncertainty in a business-as-usual context: a relatively narrow range of U.S. economic growth with no basic change in the relationship between the regional and national economies. Table 3 shows the long-range system forecast of native energy requirements, summer peak, and winter peak demand for the NSP System. Table 4 shows the North Dakota portion of the system forecast.

The forecast for the system is based on forecasts of jurisdictional sales by major customer class: residential with and without space heating, small commercial and industrial (“SC&I”), and large commercial and industrial (“LC&I”). Each customer class is modeled independently for the five states included in the system. The native energy requirements are determined by applying a loss factor to total sales.

The system peak is apportioned to jurisdictions based on the native energy requirements by state and the load factor by state. Consequently, the summer and winter “peak loads” provided in Table 4 represent the North Dakota jurisdiction

customer demand at time of the system seasonal peak demand. This “coincident” demand is appropriate for generating capacity requirement forecasting.

It is important to note, however, that a “non-coincident” peak demand must be used in evaluating transmission capacity requirements. This is because the transmission system must be able to supply the full local customer demand at all times. Due to load diversity caused by weather variations within the multi-state system, peak customer demands in Xcel Energy’s North Dakota service areas can be as much as 25 percent higher than the demands registered during the hour in which the total system peak demand occurs. It is these local “non-coincident” peak demands that determine the need for transmission improvements required for load serving functions.

**Table 2. Historical Energy and Peak Load Requirements
(1986 - 2010) North Dakota portion of NSP System**

Year	Energy (GWh)	Annual Growth	Non- Coincident Peak Load (MW)	Annual Growth
1986	1,553	0.6%	311	-3.4%
1987	1,553	0.0%	312	0.3%
1988	1,658	6.8%	323	3.5%
1989	1,844	11.2%	374	15.8%
1990	1,904	3.3%	399	6.7%
1991	1,925	1.1%	373	-6.5%
1992	1,883	-2.2%	376	0.8%
1993	1,771	-5.9%	333	-11.4%
1994	1,796	1.4%	360	8.1%
1995	1,916	6.7%	362	0.6%
1996	1,984	3.5%	382	5.5%
1997	1,911	-3.7%	351	-8.1%
1998	1,958	2.5%	352	0.3%
1999	1,950	-0.4%	363	3.1%
2000	2,053	5.3%	370	1.9%
2001	2,048	-0.2%	384	3.9%
2002	2,119	3.5%	403	4.8%
2003	2,171	2.4%	395	-2.0%
2004	2,158	-0.6%	403	2.2%
2005	2,289	6.1%	426	5.7%
2006	2,353	2.8%	439	3.0%
2007	2,378	1.1%	463	5.5%
2008	2,478	4.2%	427	-7.8%
2009	2,379	-4.0%	427	0.0%
2010	2,422	1.8%	445	4.2%

Table 3. Forecast of NSP System Energy and Peak Load Requirements (2011 - 2029)

Year	Energy (GWh)	Summer Peak Load (MW)	Winter Peak Load (MW)
2011	45,975	9,140	6,953
2012	46,377	9,245	7,042
2013	46,318	9,293	7,059
2014	46,795	9,415	7,153
2015	47,253	9,530	7,239
2016	47,748	9,631	7,316
2017	47,990	9,725	7,388
2018	48,267	9,810	7,457
2019	48,537	9,888	7,521
2020	48,867	9,969	7,595
2021	49,198	10,062	7,672
2022	49,528	10,132	7,730
2023	49,864	10,196	7,783
2024	50,234	10,253	7,832
2025	50,646	10,301	7,873
2026	51,069	10,348	7,914
2027	51,489	10,403	7,962
2028	51,921	10,452	8,007
2029	52,338	10,501	8,051

Average Annual Growth Rate, 2011-2029:

% growth: 0.7% 0.8% 0.8%

- Notes:**
- 1) Peak Load is *coincident* to the NSP System peak.
 - 2). Winter Peak = MISO Winter Peak season, 2011 is 2011 - 2012 winter peak.
 - 3) Peak Load is the Base Peak (Uninterrupted)

**Table 4. Forecast of Energy and Peak Load Requirements (2011 - 2029)
North Dakota Portion of NSP System**

Year	Energy (GWh)	Summer Peak Load (MW)	Winter Peak Load (MW)
2011	2,482	327	426
2012	2,509	331	433
2013	2,536	338	440
2014	2,567	344	445
2015	2,592	350	451
2016	2,625	356	457
2017	2,653	362	465
2018	2,683	368	469
2019	2,713	375	476
2020	2,747	381	481
2021	2,783	387	488
2022	2,818	394	495
2023	2,850	401	502
2024	2,886	407	508
2025	2,924	414	515
2026	2,959	421	522
2027	2,993	429	530
2028	3,030	436	537
2029	3,066	443	544

Average Annual Growth Rates, 2011-2029:

% Growth:	1.2%	1.7%	1.4%
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- Notes:**
- 1). Peak Load is *coincident* to the Xcel Energy system peak.
 - 2). Winter Peak = MISO Winter Peak season, 2011 is 2011 - 2012 winter peak.
 - 3.) Peak Load forecast growth from 2021 - 2029 is based on average summer and winter ND peak growth rates from 2011 - 2020.

APPENDIX A
Schedule of ADP Filings.

The following tables identify those projects for which we intend to seek an ADP finding from the Commission, along with a page number in this Plan where a description of the proposed project can be found.

Pending ADP petitions

Project	Date Filed	Docket Number	Description (page number)
CapX2020 Brookings Transmission Project (ADP Confirmation ⁵)	4/29/2011	PU-09-678	11
Two Prairie Island Nuclear Generating Station Projects: New Unit 2 Steam Generators and Units 1 and 2 Extended Power Uprates	4/19/2010	PU-10-127	3

⁵ Note that all of the CapX2020 Phase I Projects were granted Advanced Determination of Prudence by the ND Commission on October 6, 2010. For the Brookings Project, the ND Order required the Company to file for confirmation of continued prudence renewal of the ADP status once there was resolution of the cost allocation method to be applied to the project by the Midwest ISO.

Possible ADP petitions – timing and certainty of project moving forward dependent on outcome of resource planning process and other key decisions. We are willing to explore the timing of these filings with the Commission Staff.

Project	Description (page number)
North Dakota Wind Commitment	8
Black Dog Units 3 and 4 Repowering	5
Goodhue Wind PPA	8
Manitoba Hydro PPA	6
Prairie Rose Wind Project	9

APPENDIX B

Report on the Effect of Wind Generation on Baseload Plants

In the Commission's Order on the Company's application for an ADP for the Nobles Wind Project, dated August 12, 2009, in Case No. PU-08-907, the Commission included the following ordering clauses:

2. NSP will report to the extent possible, as part of its annual 10-year plan, all reductions in the energy produced at its base load generation units that would not have occurred except for the existence of wind generation. The report will include the time of the event, length of the event, base load plant affected and the amount of energy not produced at the base load plant during the event.
3. NSP will report, as part of its next 10-year plan, on the impacts and costs associated with taking coal plant production up and down to accommodate wind resources during off peak hours.

Ordering Clause 2

In response to ordering clause 2, we performed an analysis of the NSP system performance over 7,296 hours from the first hour on July 1, 2009 through the last hour on April 30, 2010. To establish a criteria as to what would constitute reductions in energy production, we looked at the set points for each unit established in our Energy Management System. Units have an economic maximum and an economic minimum set point that comprise the normal dispatch range. For the purposes of this study, we assumed that any time a unit was not operating at its economic maximum, it was "backed down". We then attributed the cause of the reduced baseload production each hour to load, wind, market dispatch, or some combination based on the net energy position for the NSP system over the hour.

As an example, let's assume load is 500 MWs, wind is 100 MWs and Sherco Unit 1 is the only baseload resource online with a maximum capability of 680 MWs. By itself,

NSP would only need 400 MWs from Sherco to serve load. If the unit were in fact dispatched to 400 MWs by MISO, we would attribute 180 MWs of backed down generation to our load ($680 - 500$), and 100 MWs to the wind. If MISO backed the unit down further to 300 MWs, the additional 100 MW reduction would be attributed to market dispatch. There are also times when baseload units remain loaded above the level necessary to serve NSP load net of wind generation due to the market wide demand for energy.

It is important to note that the cause of reductions in baseload energy production cannot be determined with certainty given the regional dispatch of generation in MISO. Wind generation may play a role in MISO market dispatch decisions, but the Company does not have enough information to determine definitively the cause of these decisions. Nevertheless, the analysis described above provides a reasonable framework for assessing the impact of wind on the NSP system.

The results show that the total amount of energy that was not produced that could have been produced during the study period if no baseload generation was backed down was 2,339,681 MWhs. Wind production contributed to 400,824 MWh or 17% of the MWhs backed down. Changes in customer load accounted for 140,936 MWh or 6% of the MWhs backed down. MISO Market Dispatch was responsible for 1,797,921 MWh or 77% of the MWhs backed down. There were many hours where baseload generation was backed down for a combination of market dispatch, wind production and customer loads.

Out of the 300 days evaluated, there were 219 cycles in which wind generation contributed to backing down base load generation. We define a cycle as the period of time over which the base load generation was backed down. As an example, on July

1, 2009, base load generation was backed down for six hours in part due to wind generation. This was considered a cycle. On April 16, 2010 during the hour beginning at 4 am, base load generation was backed down for one hour in part due to wind generation. This was also counted as one cycle.

Ordering Clause 3

Per the ADP for the Nobles Wind Project dated August 12, 2009, in Case No. PU-08-907, the Company reported on Order Point 3 in the 2010 10-year plan.