414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

**PUBLIC DOCUMENT**
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April 15, 2013

Dr. Burl W. Haar - VIA ELECTRONIC FILING -
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

Re: PETITION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION
SEEKING APPROVAL FOR A COMPETITIVE RESOURCE ACQUISITION
PROPOSAL AND FOR A CERTIFICATE OF NEED
DOCKET NO. E002/CN-12-1240

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, is pleased to submit to the Minnesota Public Utilities Commission this proposal to construct three 215 MW combustion turbine generators with in-service dates between 2017 – 2019. The Company respectfully requests a Certificate of Need for the first unit, which it proposes to construct at the Company's Black Dog generating plant in Burnsville, Minnesota, for service in 2017. The Company proposes the second and third units to be constructed at a new plant site in the Red River Valley, near Hankinson, North Dakota, for service in 2018 and 2019.

Our proposal provides cost-effective generating capacity to ensure reliable service to our customers to meet the need identified by the Commission in the Company's recent Resource Plan docket. The need is for approximately 150 MW in 2017, which may increase up to as much as 500 MW by 2019. Our proposal also provides significant flexibility to adjust the implementation schedule if the Commission finds circumstances warrant. In addition, we propose a creative cost-recovery mechanism that ensures ratepayers will receive the benefits of a cost-competitive proposal and provides the Company with maximum incentive to keep costs as low as possible.

Minnesota Rules Chapter 7849.0210, subpart 1 establishes an application and processing fee of $10,000, plus $50 for each megawatt of proposed plant capacity and such additional fees as are reasonably necessary for completion of the evaluation of need for the proposed facility. Our proposal is for 645 MW of generating capacity, resulting in a total fee of $42,250. A check in that amount accompanies our application.

Certain information in Appendix C of the Company's proposal has been designated Trade Secret pursuant to Minnesota Statute § 13.37, subd. 1(b). This filing includes the public version of Appendix C. The Trade Secret version of Appendix C is being separately e-filed, and will be mailed to those parties that are eligible to review the nonpublic information it contains.

We are serving our proposal on the Office of the Attorney General, the Department of Commerce, and others on the service list in this docket. A summary of this filing will be served on parties on the attached miscellaneous service list, and to the parties in the Company's current general rate case. Copies of our proposal can be obtained from the Xcel Energy web site at www.xcelenergy.com.

Please contact me at james.r.alders@xcelenergy.com or (612) 330-6742 if you have any questions regarding this filing.

Sincerely,

/s/

JAMES R. ALDERS
STRATEGY CONSULTANT
REGULATORY AFFAIRS

Enclosures

c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

| | |
|---|---|
| Beverly Jones Heydinger | Chair |
| David C. Boyd | Commissioner |
| Nancy Lange | Commissioner |
| J. Dennis O'Brien | Commissioner |
| Betsy Wergin | Commissioner |

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF A COMPETITIVE RESOURCE ACQUISITION PROPOSAL AND FOR A CERTIFICATE OF NEED

Docket No. E002/CN-12-1240

**PROPOSAL**

## SUMMARY

On April 15, 2013, Northern States Power Company, doing business as Xcel Energy, submitted to the Minnesota Public Utilities Commission its proposal and Certificate of Need request to meet the need identified by the Commission in the Company's recent Resource Plan docket. The need is for approximately 150 MW in 2017, which may increase up to as much as 500 MW by 2019. The Company's proposal is to construct three natural-gas-fired, simple-cycle, 215 MW combustion turbine (CT) generators sequentially to match the identified need. The first combustion turbine unit would be located at the Xcel Energy's Black Dog generating plant in Burnsville, Minnesota, with an in-service date of 2017. The second and third units would be located at a new plant site in the Red River Valley near Hankinson, North Dakota, with in-service dates of 2018 and 2019.

Others may also be submitting proposals to meet Xcel Energy's identified need for the 2017-19 time period.

# APPLICATION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR APPROVAL OF A COMPETITIVE RESOURCE ACQUISITION PROPOSAL AND FOR A CERTIFICATE OF NEED

Docket No. E002/CN-12-1240

**April 15, 2013**

**Submitted by**
**Northern States Power Company**

**Competitive Resource Acquisition Filing**
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**Appendices**

# 1 Summary

## 1.1 Introduction

Northern States Power Company, doing business as Xcel Energy (Xcel Energy or the Company), is pleased to submit this proposal for consideration by the Minnesota Public Utilities Commission. We respectfully seek approval of our proposal to construct three 215 MW combustion turbine generators with in-service dates between 2017 and 2019 (the Proposal). The Company also respectfully requests a Certificate of Need for the 2017 unit, which is proposed to be located in Minnesota.

This Proposal provides approximately 645 MW of cost-effective generating capacity to ensure reliable service to our customers in a time frame that will closely match the Commission's finding in our last Resource Plan "that the current resource plan demonstrates Xcel's need for an additional 150 MW in 2017, increasing up to 500 MW in 2019."[1] Our Proposal also provides significant flexibility to adjust the implementation schedule if the Commission finds circumstances warrant. Finally, we propose a creative cost-recovery mechanism that ensures ratepayers will receive the benefits of a cost-competitive proposal and provides the Company with maximum incentive to keep costs as low as possible.

### 1.1.1 Description of the Company's Proposal

The Company's Proposal to meet the generation need identified in the Resource Plan Order is to construct three natural-gas-fired, simple-cycle, combustion turbine (CT) generators, sequentially to match the identified need. We propose the following deployment locations and schedule:

- **Black Dog Unit 6:** The first 215 MW combustion turbine would be placed in service in 2017 at the Company's existing Black Dog plant in Burnsville. This unit would substantially replace the coal fired generating capacity at this site, which is scheduled to retire in 2015. The Black Dog plant site allows the Company to maximize the use of existing infrastructure and maintains generation within our largest load center, which enhances operating reliability.

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[1] *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, Docket E002/RP-10-825, ORDER APPROVING PLAN, FINDING NEED, ESTABLISHING FILING REQUIREMENTS, AND CLOSING DOCKET, Order Point No. 2 (March 5, 2013)( "Resource Plan Order").

- **Red River Valley Unit 1 (RRV 1):** The second 215 MW combustion turbine and associated natural gas, transmission, and interconnection facilities would be placed in service in 2018 at a new site in the Red River Valley, near Hankinson, North Dakota. This unit would take advantage of existing nearby transmission and natural gas infrastructure and will enhance geographic diversity in our supply portfolio.[2]

- **Red River Valley Unit 2 (RRV 2)**: The third 215 MW combustion turbine would be placed in service in 2019 and added to the plant site established for RRV 1. Alternatively, Xcel Energy could deploy RRV 1 and RRV 2 together in either 2018 or 2019 with corresponding cost savings through simultaneous deployment.

### 1.1.2 Benefits of the Proposal

Our Proposal provides a number of benefits that make it a good choice for our customers.

*Ensures a Reliable Power Supply for Our Customers*

This Proposal closely matches the resource need identified in the Commission's Resource Plan Order. Our incremental approach and implementation schedule does not rely on building a larger power plant in 2017 that would result in significant excess capacity. Nor do we defer all construction until the need grows in later years as this would risk capacity shortfalls in 2017 and would not meet the Commission's instruction to satisfy the identified 2017 need. The combined capacity associated with our Proposal ensures that the Company will have adequate resources in the latter part of the decade to reliably meet customer's electricity demands without overreliance on the MISO electricity market.

*Provides Important Flexibility*

Our Proposal provides important flexibility to adjust generation deployment to better manage the inherent uncertainty in customer demand forecasts and the impact of capital commitments on customer rates. The combustion turbines we propose have relatively short development schedules, allowing us to add generating

[2] Xcel Energy is concurrently seeking the approval of the North Dakota Public Services Commission for the two units to be located in the Red River Valley.

capacity in smaller increments and strategically place it in our system. As new information becomes available in 2014 and 2015, the Commission could decide that it is more appropriate to accelerate or delay part of the new generating capacity to better match customer needs. As part of our Proposal, we offer to provide status updates in the fall of 2014 and 2015 to allow the Commission an opportunity to reassess the need and adjust deployment of the 2018 and 2019 units if that is consistent with evolving circumstances. We also provide the Commission with the flexibility to cancel one or two of the CTs at a relatively nominal cost to ensure that the Commission has the ability to react to future circumstances.

*Implements a Conservative Approach*

Our approach delivers capacity sufficient to satisfy current identified need and is appropriately conservative to ensure that Xcel Energy will have sufficient generating resources under reasonably foreseeable circumstances in the 2017 to 2019 timeframe. We recognize that two specific factors contribute to ongoing uncertainty about future system resource needs: (i) uncertainty in customer demand forecasts, and (ii) changing MISO reserve margin requirements. Both of these factors are accounted for in our Proposal.

First, as Minnesota continues to work through the effects of the recent recession, there is uncertainty about whether and how customer demand may grow. Recent demand forecasts are lower than that used in establishing the potential resource need in this docket but have varied with forecasts of economic recovery. While some indicators suggest continued slow growth, the Company is mindful of our obligation to serve our customers under all circumstances. As a result, the Company conservatively proposes generation sufficient to satisfy the forecasted demand as established in our Resource Plan.

Second, assessments of the amount of generation that needs to be in place to ensure reliability in the MISO market are changing. Reserve requirements have gone down in 2013 due to the use of a new methodology at MISO. But it is not yet clear whether recent reductions in reserve margins will be sustained over time. Further, it is not certain how Xcel Energy's particular operating characteristics will fit within the new MISO methodology. Because of these uncertainties coupled with our obligation to serve, we concluded that it is an appropriate investment for our customers to deploy capacity on the schedule we have proposed to minimize the risk of any capacity shortfall, particularly if the economic recovery accelerates.

Nonetheless, our flexibility to adjust implementation can be used to the benefit of customers. Our Proposal is modular, that is, the deployment of each CT unit can be independent of the others, which allows adjustments to schedules or even cancellation of projects after the Commission makes its initial resource selections in this proceeding but before major expenditures are made.  This modular approach is beneficial as it allows the Commission to adjust deployment and better respond to the uncertainty associated with forecasting future energy usage and resource needs.

*Enhances the Reliability of Local System Operations*

We have chosen to deploy needed generation at locations that will appropriately balance the cost of generation as well as reliability of our system and local considerations for our power supply.  These considerations provide important diversity to the overall benefit of our system and customers.

The Black Dog power plant has provided important capacity, energy, and system stability for over 50 years by delivering power to the 115 kV transmission system that directly serves distribution substations throughout our largest load center, the metropolitan Twin Cities area.  Black Dog Unit 6 will connect directly to the 115 kV system, ensuring that this important generation source will continue to provide power to the lower voltage system directly to customers.  That system configuration exposes customers' power supply in the metro area to fewer equipment failures and thus enhances reliability.

Xcel Energy serves approximately 80,000 customers in the greater Red River Valley, including the communities of Fargo and Grand Forks. This part of the Xcel Energy system is heavily dependent upon the high voltage transmission network to deliver power from distant generation.  Indeed,  at this time, Xcel Energy has no power plants located in the Red River Valley.  This is the only major load center in our system without Company-controlled generation.

The Hankinson site appropriately balances low cost and strategic location.  This site is about 70 miles from our Fargo load center, near the juncture of the 230 kV transmission system and a large natural gas pipeline, thereby providing strong economic justification.  At the same time, this Red River Valley site places generation closer to our regional load centers than our Twin Cities generators. The addition of generation in the Red River Valley will moderate reliance on the high voltage transmission system and will enhance geographic diversity and our ability to restore power in the event of a disruption.

*Is the Most Economical Generation Addition We Can Provide*

Our Proposal to deploy three CTs in geographically diverse areas is the most cost-effective addition we have identified for our customers. Locating one CT at the Black Dog site keeps costs down by maximizing the use of existing power plant and transmission infrastructure. Likewise, the Hankinson site takes advantage of nearby available natural gas and transmission infrastructure that results in an overall competitive option.

Adding CTs requires lower capital investments than other new power plant options, and these peaking plants fit well with our existing generation portfolio. The addition of peaking capacity allows us to more fully utilize existing, intermediate generation, such as the High Bridge and Riverside combined cycle plants. The new CTs with their low capital cost but higher operating cost will be called on only a few hours a year during peak power demand periods. Thus, the overall cost of electricity and rates will be kept lower. Plus, our Proposal affords the Commission additional flexibility if it wants to consider adding one or two CTs in conjunction with other resource choices.[3]

*Creative Incentive Mechanism*

We have taken care and worked closely with vendors to make our estimates as accurate as possible and have included contingency estimates to reflect uncertainty at this stage in development. We have made considerable efforts to make our Proposal comparable to those that may be received from independent power suppliers to ensure fair evaluation. However, as a rate regulated utility we have the opportunity to deliver additional value to customers if actual development costs are lower than estimated.

We appreciate the desire for discipline in developing project proposals that can be relied upon, and we agree that the Commission should favor proposals that protect ratepayers by providing incentives to keep costs as low as possible. Our recent experience with the Metropolitan Emissions Reduction Project (MERP) demonstrates that the Commission values cost certainty and incentive mechanisms that encourage the utility to keep costs as low as possible. Since some uncertainty

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[3] We note that as discussed in our Resource Plan proceeding, it is possible under unique circumstances that intermediate rather than peaking capacity may be the more cost-effective resource. As this process unfolds with actual proposals from independent power suppliers, more information will become available that could affect the final choice of generation.

is inherent in the development of any major project, Xcel Energy is proposing a cost recovery mechanism that will provide maximum ratepayer value.

We include in this filing a cost recovery proposal that provides a financial incentive to the benefit of customers. We propose that each unit be treated separately for purposes of cost recovery and each project's ROE be adjusted up or down during the first five years of recovery based on actual costs. We propose an ROE penalty should actual costs exceed our estimates. Similar to MERP, this mechanism will provide us with a real incentive to keep costs as low as possible and deliver additional benefits (reduced cost) to our customers that typically are not available from an independent power supplier.

## 1.2 Regulatory Framework

The Competitive Acquisition Process approved in our 2004 Resource Plan (Docket No. E002/RP-04-1752) was outlined in the Company's August 28, 2006 filing in that proceeding. In summary, when the Company is proposing a self-built alternative, the Commission specified a certificate of need-like process where:

- The Company submits a detailed filing regarding its proposal containing information as laid out in Minnesota rules and statutes governing certificate of need applications.
- On the same date, interested competitors provide their proposals in similar certificate of need like detail, including proposed contract terms.
- A contested case is conducted before an administrative law judge, with findings and recommendations to be provided to the Commission.
- The Commission considers the developed record and issues its selection decision and grants certificates of need as appropriate.
- The Company and any selected independent power supplier have four months to negotiate a Power Purchase Agreement for Commission approval.

In its Resource Plan Order, the Commission initiated the Competitive Resource Acquisition Process seeking proposals to meet the identified need as follows:

2. The Commission finds that the current resource plan demonstrates Xcel's need for an additional 150 MW in 2017, increasing up to 500 MW in 2019.

3. Participants in Xcel's competitive resource acquisition process, Docket No. E-002/CN-12-1240, *In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy to Initiate a Competitive Resource Acquisition Process*, may propose a variety of resources to meet Xcel's need, including --

    a. Resources to address all or a portion of the identified need;

    b. Peaking resources, intermediate resources, or a combination of the two; and

    c. Resources that rely on new or existing generators.

In its March 5, 2013 Order Extending Bidding Deadline and Refining Procedural Framework ("Procedural Order") in the instant Docket, the Commission directed the Company and any competitors to file their proposals by April 15, 2013.

By this Proposal, Xcel Energy respectfully requests the Commission to (i) approve the Proposal, and (ii) grant a Certificate of Need for the 215 MW Unit 6 combustion turbine addition at the Black Dog plant in Burnsville. The Company is also making concurrent filings with the North Dakota Public Service Commission, seeking an Advanced Determination of Prudence for our Proposal and Certificates of Public Convenience and Necessity for the two Red River Valley units. We plan to make additional filings for site permits and operating permits later in the year and in 2014.

To ensure a fair and balanced evaluation, the Commission should develop and apply an analytical framework for a robust evaluation of the bids. It will be important to achieve an 'apples to apples' analysis that focuses on the overall costs and benefits of a given proposal, factoring in all of the costs associated with the proposal. Since bidders have wide latitude in the type of proposal they make (e.g., long-term, short-term, PPA, build-transfer, utility ownership), the first year cost of energy and the nominal total PPA cost in isolation will be of limited value since those numbers will not inform the Commission of the overall cost and benefits of a particular proposal to our customers.

First and foremost, it will be important for the Commission to include review criteria that fairly compares all of the proposals and allows the Commission to make a decision that is in the best interest of ratepayers over the life of the resource purchase. It will provide a basis to compare large and small, long and short alternatives and a host of other variables. Use of Strategist will be important to creating a level playing field for all proposals. In addition to Strategist, the Company recommends the Commission's analysis include other important factors, such as the cost of capital equipment and any pricing/cost uncertainty that may be present in a proposal; the cost and availability of fuel; operations and maintenance costs; the price of energy under a long-term PPA versus the estimated cost of utility-owned proposals; short-term versus long-term proposals; and adjustments necessary to account for indirect costs that may be associated with a given project.

## 1.3 Resource Need

This Competitive Acquisition Process is the culmination of a lengthy review of resource needs in the Company's 2011-2025 Resource Plan. In the course of that review, the Company worked with the Department to analyze generating resource needs. The result was a determination by the Commission that the Company may face a capacity deficit beginning in 2017 of approximately 150 MW that increases up to 500 MW by 2019.

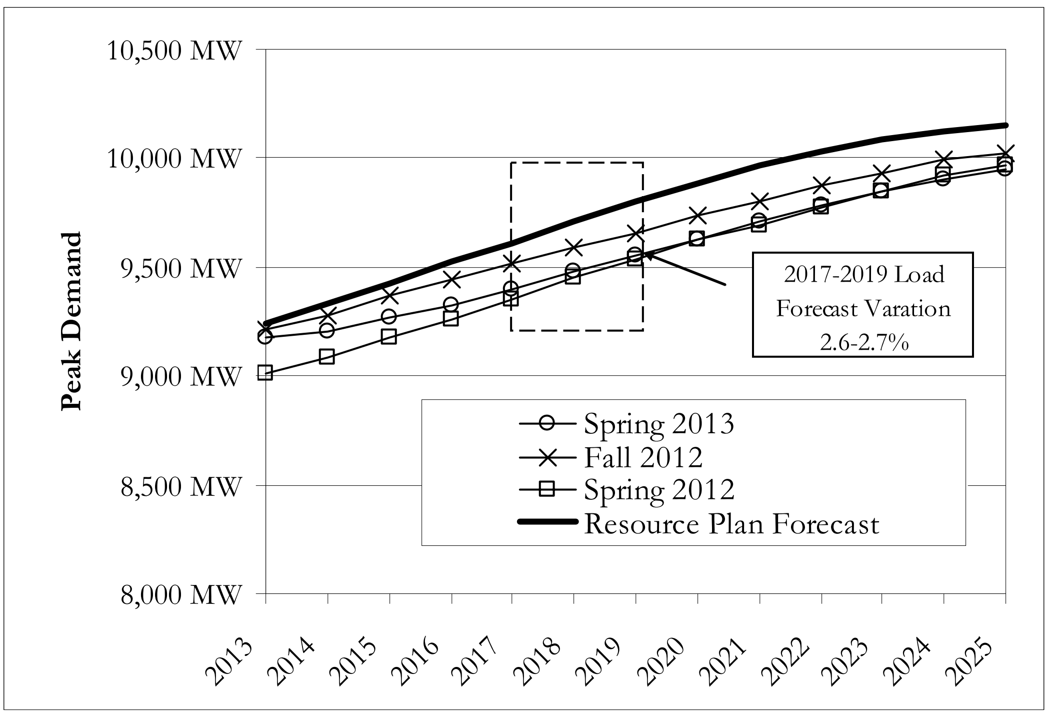
Xcel Energy meets its customers' needs for electricity with a combination of Company-owned-and-operated generating facilities, and long- and short-term power purchases. Our December 2011 Resource Plan Update forecast included the adjustments recommended by the Department in their June 2012 comments, and the reserve generation margin based on MISO's unforced capacity (UCAP) methodology. Based on our forecast of customer needs, adjusted for aggressive DSM programs, and a planning reserve margin of 3.8 percent, our analysis identified potential generating capacity deficits of about 150 MW in 2107 growing to about 450 MW by 2019.

Our Proposal is designed to meet the resource needs identified by the Commission in our most recent Resource Plan docket. However, as noted above, our Proposal also provides the Commission with flexibility to defer or even cancel one or more components of the Proposal.

### 1.3.1 Forecasting Uncertainty

There is inherent uncertainty in assessments of generation capacity requirements. Resource need projections depend heavily on underlying forecasts of peak power demand. Demand forecasts in turn depend heavily on forecasts of economic activity. Uncertainty has been amplified in recent years due to the recent economic recession. Abrupt changes like this make it more difficult to predict economic performance several years out than during a more stable economic period. These difficulties are illustrated in the changes in our demand forecasts in recent years. Estimates of peak demand have varied up and down over the last three years. Relatively small changes in estimates of growth rates have moved projections of demand in the latter half of the decade up and down by approximately 250 MW. However, the range of forecasts falls within an error band or probability range of only two percent-to-three percent.

**Figure 1-1**
**Peak Demand Forecasts**




Rather than treat any one forecast as preferred, we believe it is prudent to consider the range of forecasts we have experienced recently. Nonetheless it is possible that a trend toward lower forecasts will become more apparent over the next few years.

### 1.3.2 Recent MISO Reserve Margin Changes

As discussed in our Resource Plan proceeding, change is also occurring in the way MISO calculates generation reserve margins necessary to ensure system reliability. Starting in 2013, MISO's reserve margin calculation for individual utility systems has been adjusted to reflect the utility's peak demand at the time of the region's peak. Xcel Energy's average system demand at the time of MISO peak has on average been about five percent lower than our own peak. Because our peak has not been coincident with MISO's, our reserve obligation is reduced. For 2013, the Company's reserve margin is approximately 200-300 MW lower than what we used in our Resource Plan analysis. This suggests that our reserve requirements may remain lower in the future. However, Xcel Energy's demand at MISO peak has varied substantially and our peak has not been coincident with MISO's in five of the last eight summer seasons. It is not clear at this time how reserve calculations might change between now and 2017 to 2019. Relatively small changes in coincidence factors combined with adjustments in UCAP capacity calculations and adjustments in annual loss of load expectation calculations can swing reserve requirements on our system measurably.

Under these circumstances, we believe a conservative approach is warranted to ensure adequate generating capacity under all reasonably plausible outcomes. New generation on our system is also beneficial as it insulates our customers from overreliance on the MISO market. Further, small surpluses in generating capacity can result in excess energy available to sell into the market, which serves to reduce costs for our customer. We conclude the generating capacity assessment from our Resource Plan analysis presents reasonable targets for generation additions in the 2017 to 2019 timeframe. As noted earlier, the incremental nature of our Proposal also provides added flexibility to help manage the uncertainty. The size of generation additions are relatively small and timing can be adjusted relatively easily, even after the Commission makes its generation decision at the end of the year.

## 1.4 Project Description

The design of the peaking capacity we propose is based on the performance characteristics of F class combustion turbines. The CT technology available today is significantly improved over that available even a few years ago. The model F class CTs now commercially available have fast start capability, reaching 150 MW in 10 minutes from a cold start, and operating in a range of at least 50 to 100 percent load while meeting emission limits, with faster ramp rates over the load range. Maximum output during summer heat and humidity conditions is approximately 215 MW. The maintenance and overhaul cycles have also been significantly improved. The base performance with respect to full load capacity and heat rate have also been improved.

Each combustion turbine-generator consists of the following equipment in series:

- Inlet Air Filter and evaporative cooler, which cleans and cools the air entering the turbine;
- Compressor, where air is drawn in and compressed;
- Combustor, where the air/fuel mixture is ignited;
- Power Turbine, where the combusted gases expand to rotate a generator turbine; and
- Generator, which converts mechanical energy to electrical energy.

The generator step-up transformer will be located next to the generation block. The transformer increases the output voltage to either 115 kV or 230 kV substation voltages. Auxiliary transformers will be used to convert some of the output power to lower voltages for use by the unit's auxiliary equipment.

### 1.4.1 Black Dog Unit 6

Black Dog Unit 6 will be located in the existing powerhouse, in the area where Unit 4 currently is located. The exhaust stack will be approximately 200 feet tall and will be located adjacent to the unit, in the area of the existing Unit 4 boiler. Unit 6 will be connected to the existing 115 kV switchyard and transmission system. No upgrades of the 115 kV transmission system are required.

The unit will be fueled entirely by natural gas. Center Point Energy currently serves the Plant site. We plan to secure additional natural gas supply through a competitive process beginning in early 2014. We anticipate that the successful bidder may need to replace the existing pipeline serving the plant with a new higher pressure natural gas line from the Cedar Town Border station to the plant.

Generation block construction will begin after a site permit and other approvals are obtained. Unit 6 will be constructed in 2016 and 2017. Decommissioning, demolition and removal of the Unit 4 turbine, generator, boiler, and other components will begin in the fall of 2014 and be completed prior to constructing Unit 6. Start-up of the Unit would occur in early 2017. Unit 6 is expected to be in commercial operation late in the 1$^{st}$ quarter of 2017.

The capital cost estimate for Black Dog Unit 6 is presented in Appendix C.

### 1.4.2 Red River Valley Units 1 and 2

We have chosen to locate our Red River Valley units near the community of Hankinson, North Dakota, near the confluence of the 230 kV transmission system and major natural gas pipeline assets. This location will provide us with significant cost savings by maximizing the use of the available infrastructure. While a specific plant site for the two units in the Red River Valley has not been selected at this time, we anticipate the plant will utilize less than 35 acres of 160 acres of property we plan to acquire to provide a buffer from surrounding uses.

It is anticipated that the tallest structure will be the stack at approximately 65 feet tall. The tanks, combustion turbine, and maintenance and operations building are all expected to be less than 40 feet in height.

The combustion turbine facility will utilize natural gas. We propose to construct and own the short gas pipeline necessary to connect the plant to the fuel supplier. Water supply will either be from an on-site well or by truck.

Red River Valley Units 1 and 2 will connect to a new 230 kV substation with a short double circuit 230 kV line. We anticipate the system interconnection will require an upgrade of the existing Hankinson to Wahpeton 230 kV line.

Red River Valley Units 1 and 2 can be constructed separately with sequential in service dates, or together as one project. A single project development approach can reduce the capital costs. The capital cost of Red River Valley Units 1 and 2 are presented in Appendix C.

### 1.4.3 Operation

The CT units will be integrated into our remote dispatch control center. We expect to use the units for peaking service, dispatching them after all incrementally lower cost and "must run" units. The units are expected to be dispatched primarily during higher system load periods in the summer and winter months, during peak demand periods, with annual capacity factors between four and ten percent.

These units will also serve to vary output as system load requirements change, and intermittent or variable non-dispatchable generation such as wind power changes. The CT units will be able to commence start up after a 30-minute notice, and will have the ability to increase power output at approximately five to ten MW per minute.

## 1.5 Environmental Performance and Land Use Impacts

Our Proposal has been designed and located to minimize land use conflicts as well as air and water quality impacts.

*Land Use*

Black Dog Unit 6 takes advantage of an existing site with existing infrastructure and does not create new land use impacts since it will be located inside the existing power house. The Black Dog plant is located on a 35 acre parcel which is well buffered within an approximately 1,900 acre area owned by the Company. The area under consideration for the Red River Valley units is in a rural setting with low residential densities. While less than 35 acres will be required for the developed portion of the plant site, we propose to acquire a 160 acre area to provide ample buffer from surrounding activity. We anticipate the plant will be connected to the transmission system with a relatively short 230 kV transmission line.

*Air Quality*

Natural gas-fired simple cycle combustion turbine technology is among the most efficient and cleanest means of generating utility-scale electricity. Natural gas combustion generates significantly less carbon dioxide ($CO_2$), particulate matter, sulfur dioxide ($SO_2$), and toxic air emissions (including mercury (Hg)) than oil or coal.

The primary constituents of concern resulting from combustion of natural gas are nitrogen oxides ($NO_x$), carbon monoxide (CO), and volatile organic compounds (VOCs). Our Proposal will control $NO_x$ emissions through use of dry low-$NO_x$ burners and selective catalytic reduction systems (SCR). Good combustion practices and oxidation catalysts will be used to control emissions of fine particulates, CO, and VOCs.

The Company has conducted preliminary ambient air quality analysis using EPA approved dispersion models. Our analysis demonstrates our Proposal will comply with all applicable air quality requirements at the Black Dog and Red River Valley sites.

The Company will make application to the Minnesota Pollution Control Agency and the North Dakota Department of Health for air quality operating permits in 2014.

*Water Appropriation and Quality*

Simple cycle combustion turbines can operate without significant quantities of water. We estimate these peaking units will operate without water inputs over 80 percent of the time. We anticipate water will be injected for evaporative cooling of inlet air up to 20 percent of the time, only when maximum power output is needed. Inlet air cooling enhances operational efficiency of the units during the warmest days of the year. The evaporative cooling process consumes a small amount of water, but increases output about 5 to 10 percent depending on the relative humidity during hot summer day operation. At the Black Dog site, groundwater from an existing well will supply evaporative cooling water and other water needs. No increase in the groundwater appropriation rate or annual withdrawal volume will be required. The North Dakota site would require new groundwater wells to provide for site water needs. Groundwater appropriations permitting would be required. Lacking an adequate groundwater supply, water can be trucked in and stored on-site.

*Noise*

The units we propose will be designed to comply with state and local noise standards and are not expected to have a significant impact. Black Dog Unit 6 will be inside the existing power house which is located in an isolated area, with the nearest residences located more than 1,500 feet away. We anticipate the Red River Valley plant site will be in predominantly a rural setting with low population density. The 160 acre property will provide adequate buffer to minimize noise intrusions.

## 1.6 Alternatives

In developing this Proposal, the Company investigated a number of alternatives. Our analysis continues to demonstrate that our peaking proposal is the most cost-effective resource addition we can provide and does not conflict with Minnesota's energy policy goals. We look forward to evaluating the proposals of others in this competitive acquisition proceeding to determine if there are other opportunities to bring additional value to our customers.

*Type*

We reported in the Resource Plan proceeding that installing peaking generation results in a lower cost of energy over the long term than the alternative of building a single, combined cycle plant to meet the resource need through 2019. We have replicated the analysis using the estimates presented in this filing and confirmed the result. Peaking resources fit well with our existing mix of generating resources. We can more fully utilize coal fired generation at Sherco and King as well as existing combined cycle units at Riverside and High Bridge before making much larger capital commitments necessary for a new combined cycle plant. The lower capital commitment also keeps customers rates lower in the short term. As noted in the Resource Plan docket, an independent power supplier may be positioned to add combined cycle generating capacity without having to commit to an entirely new combined cycle plant. Xcel Energy does not have that alternative available.

*DSM*

Xcel Energy has one of the most aggressive conservation and demand side management programs in the nation and we continue to investigate ways in which we can help our customers reduce their energy use and manage their bill. We have been very successful in working with customers to help manage system peak demand with rate discounts that allow us to interrupt service. We have the capability of reducing peak demand by over 1000 MW through demand response programs. The combination of conservation and demand reduction has allowed us to eliminate the need for several new power plants which saves all customers money.

Our analysis assumes we will continue to achieve Minnesota's conservation policy goals.

While there may be additional conservation and demand response opportunities on our system, we do not believe these represent a reasonable alternative to the addition of generation in the 2017 to 2019 timeframe. The amount of new conservation and interruptible load that can be arranged is uncertain. The cost of obtaining additional conservation and demand response is uncertain. The risk is high that efforts to add DSM might end up falling short of projections. Rather than relying on DSM instead of new generation, we believe a better course is to work to increase DSM over the next several years in parallel with the development of new generation. When new demand response is added to our system it can be incorporated into subsequent resource need assessments to eliminate the need for future generation. As we have noted elsewhere, our Proposal to add peaking generation incrementally provides the Commission the flexibility to adjust how resource acquisition proceeds in 2014 and 2015 should demand response additions materialize and resource need decline.

*Renewable Generation*

We have also investigated the potential to meet the anticipated resource need with renewable based generation. Biomass and hydro power are the only renewable based resources that can provide reliable dispatchable generating capacity. The opportunities for additional hydro power on our system are minimal. Even if new biomass generation could be added to our system in the available timeframe it is much more expensive than our Proposal, and the reliability of fuel supplies have been questioned. Wind and solar generation are not peaking or intermediate resources since production is intermittent or varies substantially and cannot be effectively dispatched. MISO rules allow only 13 percent of installed wind generation to be counted toward resource requirements, and approximately 50 percent of solar generation.[4] In theory, over 3,000 MW of new wind power, nearly twice what is on the system today, would be required to replace the accreditable capacity of a dispatchable resource like our Proposal. Regardless of the cost assumed, the amount of new wind or solar generation required to meet a 500 MW resource need is much more expensive than our Proposal, and raises concerns about whether the system could operate reliably.

In fact, our peaking Proposal should not be viewed in competition with the addition of wind and solar generation to our system. Wind power is an energy source that can reduce operation at other plants. We have been successful in keeping the cost of electricity lower than it otherwise would be with over 1800 MW of wind generation on our system that reduces fuel consumption and other energy production costs. Once more we have the opportunity to add additional wind generation to our system with the extension of the federal production tax credit. We issued an RFP in February and have received proposals for additional wind power, and will bring the results of competitive bidding to the Commission this summer. Peaking generation and wind power serve different roles and can work in concert to keep costs low.

## 1.7 Certificate of Need Criteria

The relevant criteria the Commission uses in the Competitive Resource Acquisition Process to confirm the type, size, and timing of our need, and the best proposal to meet that need, are contained in Minnesota Statutes Section 216B.243, and in

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[4] To date, no commercial-scale solar PV system has been registered with MISO for capacity accreditation.

Minnesota Rule Chapters 7849 and 7829. The Company believes the four principle criteria of Minnesota Rule 7849.0120 are met. They are:

> *A. The probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states…,*

The demand for electricity on our system continues to grow. Without additional generation we anticipate inadequate generating resources to reliably and efficiently meet our obligation to serve. The Project provides about 645 MW of incremental capacity, phased in over a time frame where our forecasts show a need that grows from 150 MWs up to 500 MWs.

> *B. A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record…,*

Our analysis of alternatives demonstrates that the Project is the best way to meet our resource needs. The peaking resources we propose work well in concert with the rest of our existing fleet of generation to minimize the cost of electricity to our customers. Furthermore, the addition of generation at Black Dog and in the Red River Valley provides important system benefits, enhancing local operating reliability. Our Proposal does not preclude or diminish our opportunities to add cost effective renewable resources to our system. Instead the addition of peaking power to our system works well in concert with renewables expansion to ensure reliable power supply. Finally, the opportunity for competing proposals as part of this Competitive Resource Acquisition Process will help assure the Commission's decision will be in customers' best interests.

> *C. By a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health…,*

The Proposal is the most cost effective solution to maintain reliable service to our customers. It provides relatively small generation increments to meet need as it materializes with smaller, incremental commitments of land and natural resources, and will have minimal air quality impacts. Our Proposal enhances reliable service to major load centers in our system which helps ensure their economic vitality.

D. *The record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.*

Our Proposal is designed to meet all water use and air and water quality standards necessary to obtain operating permits.

# 2 General Information and Regulatory Permits

## 2.1 Applicant Information

The applicant's complete name and address, telephone number, and North American Industry Classification System and Standard Industrial Classification codes are:

Northern States Power Company, a Minnesota corporation
414 Nicollet Mall
Minneapolis, Minnesota 55401
(612) 330-5500
NAICS: 221119
SIC: 4911, 4922

The Company official to be contacted regarding the filing is:

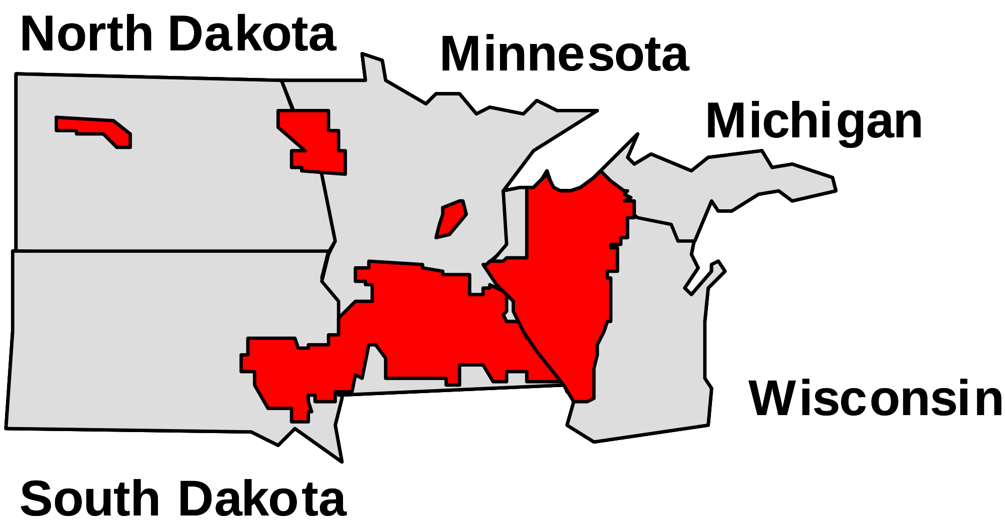
James R. Alders
Strategy Consultant
Xcel Energy
414 Nicollet Mall, GO 7
Minneapolis, MN 55401
james.r.alders@xcelenergy.com
(612) 330-6732

## 2.2 Description of Business and Service Area

Northern States Power Company is a public utility under the laws of the state of Minnesota. The legal name of Xcel Energy is Northern States Power Company ("NSP"), a Minnesota corporation. NSP and its parent public utility holding company, Xcel Energy, are headquartered in Minneapolis, Minnesota.
Xcel Energy is a public utility that generates electrical power, and transmits, distributes, and sells it to residential and business customers within service territories assigned by state regulators in parts of Minnesota, Wisconsin, South Dakota, North Dakota, and the upper peninsula of Michigan. The Company owns and operates a number of electric generation facilities serving this area using a variety of technologies and fuels including, wind, coal, oil, natural gas, hydro, refuse derived fuel ("RDF"), and nuclear. Additional wind, landfill gas, biomass and hydropower are also included in our generation portfolio through purchased power agreements.

Xcel Energy has about 1.65 million electricity customers in the upper Midwest. Figure 2-1 shows the Company's upper Midwest service territories in the states of Minnesota, Wisconsin, Michigan, North Dakota and South Dakota.

**Figure 2-1**
**Xcel Energy Upper Midwest Service Territory**




## 2.3 Competitive Resource Acquisition Process

The Commission indicated in the Company's 2004 and 2007 Resource Plan dockets that the Company should rely on competitive processes as much as possible to meet resource requirements. Thus, the Company has conducted a number of bidding processes using a Request for Proposals ("RFP") to acquire new resources. This process involves reviewing proposals received from developers, selecting the most cost effective projects, negotiating purchase agreements, and requesting the Commission's review and approval of the purchase agreements.

In the 2004 Resource Plan (Docket No. E002/RP-04-1752), the Commission approved a separate process that uses a certificate of need procedural framework whenever the Company proposes a self-build option in the competitive resource procurement process. The certificate-of-need-like process, also known as "Track 2," is designed to ensure that independent developers have the opportunity to sponsor competing generation proposals to the Company's proposal. The Track 2 process is set forth below:

- The Commission identifies the resource need to be addressed in the competitive acquisition process through its resource planning Order, which establishes parameters around size, type and timing;
- The Company submits its proposal with the information required in Minnesota rules and statutes governing certificate of need applications;
- On the same date the Company files its proposal, interested competitors provide their proposals in similar certificate-of-need-like detail, including proposed contract terms;
- After the Commission determines that the proposal filings are adequate, a contested case is conducted before an administrative law judge. At the end of the hearing process the administrative law judge provides findings and recommendations to the Commission;
- The Commission considers the developed record, issues its resource selection, and grants any associated Certificates of Need; and
- The Company and any selected power provider then have four months to negotiate a power purchase agreement and bring it back to the Commission for approval.

On November 21, 2012, the Commission issued an Order establishing a competitive acquisition process to meet Xcel Energy's next resource needs (Docket No. E002/CN-12-1240). The order directed interested persons to file in this docket by March 18, 2013 any proposals to address the resource needs identified in the Company's Commission-approved 2010 Resource Plan. The Commission subsequently extended the time for bid submission from March 18, 2013 to April 15, 2013. The order further required the Company to file a notice plan for the competitive resource acquisition process.

On January 30, 2013, the Commission approved the Company's proposed notice plan. The Company published notice and submitted its notice compliance report February 8, 2013.

On November 30, 2012, the Commission also issued an Order in the Company's Resource Planning proceeding (Docket No. E002/RP-10-825) establishing a schedule for further comment regarding the size, type and timing of our potential resource needs. After receiving comments, the Commission deliberated in February and issued its final Order, dated March 5, 2013. The Commission's final Resource Plan Order established parameters around the size, type and timing of the Company's next resource need to guide the competitive acquisition process. The Commission found that the record in the Resource Planning Docket demonstrates a resource need for an additional 150 MW in 2017, increasing up to

500 MW by 2019. The Commission also ordered that participants in the Competitive Acquisition process may propose a variety of resources to meet the Company's need including:

- Resources to address all or a portion of the identified need;
- Peaking resources, intermediate resources, or a combination of the two; and
- Resources that rely on new or existing generation.

The Commission's Resource Plan and Competitive Acquisition Orders can be found in Appendix E.

In compliance with the Commission's Orders, Xcel Energy is pleased to submit this Proposal for consideration. The Company respectfully seeks approval of our proposal to construct up to three 215 MW combustion turbine generators in the 2017-2019 timeframe. The Company also respectfully requests the Commission grant a Certificate of Need for the 2017 unit, which is proposed to be located at the Black Dog power plant site in Burnsville, Minnesota.

## 2.4 Standard of Review

In order to provide further assurance that our Proposal is the overall best option to satisfy the identified need, the Commission has established procedures that provide alternate producers the opportunity to present competing proposals. While the solicitation is focused on natural gas generation, the Commission has not limited the types of proposals that may be submitted. The Company anticipates a variety of different proposals may be offered, including long-term PPAs, short-term PPAs, build-transfer asset sales, and utility-owned generation.

If a competitor's proposal provides a better fit, then it could be selected over the Company's Proposal. If the Company's Proposal offers the best overall value for ratepayers, then it should be selected. In making its decision, it will be important that the Commission apply a consistent and comprehensive standard to ensure a fair and balanced evaluation, taking into account all of the benefits and risks associated with the proposals. The Company offers its view of the applicable standard of review for the Commission to apply, as well as the evaluation considerations that should be considered and weighed in making its decision.

### 2.4.1 Certificate of Need Standard Applies

In its order approving the Track 2 process, the Commission explained that the "[c]ertificate of need filing requirements and decision criteria are clear, comprehensive, directly relevant . . . , and easily transferable to th[is] resource procurement process."[1] The standard of review for the selection of a resource in this proceeding is that established by Minnesota Rule 7849.0120, which states that a certificate of need must be granted upon the Commission determining the following four decision criteria have been met:

> A. The probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states;
> B. A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record;
> C. A preponderance of record evidence shows the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health; and
> D. The record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

Application of this standard will allow the Commission to consider all aspects of the Company's Proposal to determine whether it is in our customers' interest to proceed. This standard also provides a robust framework for the Commission to analyze and compare alternatives that are submitted into the record through the Track 2 process.

### 2.4.2 Evaluation Considerations

In applying the Certificate of Need standard in this proceeding, the Commission should develop and apply an analytical framework for a robust evaluation of the

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[1] *In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2004 Resource Plan*, Docket No. E002/RP-0-1752, ORDER ESTABLISHING RESOURCE ACQUISITION PROCESS, ESTABLISHING BIDDING PROCESS UNDER MINN. STAT. § 216B.2422, SUBD. 5, AND REQUIRING COMPLIANCE FILING at 6-7 (May 31, 2006).

bids. The Company suggests that the Commission develop an 'apples to apples' analysis that focuses on the overall costs and benefits, factoring in all of the costs associated with a given proposal and making a decision that is in the best interests of our ratepayers under all of the circumstances.

Since bidders have wide latitude in the type of proposal they make (long-term/short-term PPA, build-transfer, utility ownership), the first year cost of energy and the nominal total PPA cost in isolation will be of limited value, since those numbers will not inform the Commission of the overall cost and benefits of a particular proposal to our customers. We recommend that the Commission utilize readily-available tools to assess the overall cost incurred by our customers over the life of each alternative. This analysis should include all relevant factors, such as the cost of capital equipment; fuel; operations and maintenance costs; the price of energy under a long-term PPA; the difference in the duration of proposals; and adjustments to take into account any indirect costs that may be associated with a given project.

*Overall Cost of Energy/Strategist Analysis*

In past competitive acquisition processes, we have successfully utilized the Strategist resource expansion model[2] to analyze the impacts of various long-range electric supply and demand alternatives on our system. We recommend that Strategist be used here as well as an important analytical tool. Use of Strategist will allow the Commission to:

- Develop and rank resource expansion plans that can meet our needs, given the input assumptions;
- Calculate the Present Value of Revenue Requirements ("PVRR") to measure the economic impacts of various planning scenarios over the life of proposals; and
- Calculate the overall impacts of the plan, using forecasted rates and values where applicable.

Strategist is useful as a planning tool in many ways. First, given a set of assumptions about the forecasted demand for electricity and the resources available to meet that demand, Strategist will optimize the operation of existing resources and add new resources to develop the expansion plan with the lowest-possible PVRR. This will have the effect of addressing differences among

[2] "Strategist" is a registered trademark of Ventyx. Ventyx developed and maintains the Strategist model.

proposals by filling in other resources when a given proposal expires, providing a long-term analysis of each proposal. This will allow the Commission to consider the different benefits and risks associated with shorter- and longer-term proposals, providing a mechanism to fairly compare the short- and long-term proposals on an equivalent basis.

One of the main cost drivers of any project or PPA will be the capital costs associated with the construction and operation of the unit. The Strategist model will allow the Commission to compare the assumed capacity payments made under a PPA to the capital costs expended for a build-transfer or utility construction project.

Strategist can also factor in a variety of other costs and risks that are inherent with various proposals. It can model contingency reserves, dispatch simulation, ancillary services, and other operating characteristics that will make a project more or less expensive under the circumstances. Strategist will include assumptions for the cost of interconnecting a project to the system, as well as the cost of network upgrades that may be required for a given project. Strategist can test the impact of delaying a project, and can assess the cost differences associated with various in-service dates among competing proposals. Finally, Strategist can test assumptions about the cost of natural gas among the proposals received.

*Pricing/Cost Certainty*

An important criteria for the Commission to consider is the pricing of a proposal and any contingencies or uncertainty surrounding the firmness of the costs of the proposal. There has already been considerable discussion in this Docket around cost containment in bids, and the preference for "cost caps" and other mechanisms that may be available to ensure that our customers obtain the lowest cost quality resource. In analyzing the proposals, Xcel Energy recommends that the Commission carefully analyze any "cost caps" that are proposed, as well as other creative mechanisms bidders may put forward to provide benefits to ratepayers.

It has been Xcel Energy's experience that PPA vendors will often request exceptions to "cost caps." PPA vendors typically argue that certain costs, such as interconnection and transmission costs, natural gas pipeline costs, and sometimes other costs, are not fully known at the time of a bid. The vendors generally point out that if those costs materialize, the vendor has no alternative but to seek a price increase because those costs are beyond the vendor's control and cannot be adequately recognized through the bid process.

The Company does not dispute that sometimes unknown costs can occur and that some costs are beyond the control of the project proponent. The Company urges that the Commission consider all exceptions and contingencies when evaluating competing proposals.

*Supply Reliability*

The reliability of the supplier will be an important variable that should be included in the Commission's analysis. A stable and reliable source of supply is an important consideration for Xcel Energy that goes beyond the nominal cost of a given proposal.

As the supplier of last resort, Xcel Energy must ensure that the resource it selects to supply our customers is reliable and will, in combination with all of the resources available throughout our fleet, be sufficient to meet our projected peak demand plus additional reserves sufficient to overcome unforeseen outages and peak usage. In selecting resources, Xcel Energy suggests that the Commission be mindful of the terms under which supply is being offered.

For example, the Company recommends that the Commission evaluate the counterparties to ensure that the supplier is reliable and that the proposal itself can be relied upon to meet our customers' needs. Relevant criteria in this inquiry should include (i) the identity of the proposer and the financial backing behind the proposal; (ii) the terms and conditions of a given proposal and the quality of the commitments being made; (iii) the relative length of proposals, (iv) the availability of replacement capacity upon expiration or termination of a particular proposal; and (v) the firmness of the proposal and the underlying project being proposed.

*Fuel Supply and Reliability*

Availability and firmness of fuel supply is another important criteria that should be considered when evaluating proposals. The presence or absence of firm natural gas supply, dual fuel capability, on site storage, and the proximity of fuel sources and pipelines will all be important considerations in evaluating proposals.

The Commission is likely to receive proposals for combustion turbine peaking facilities as well as combined cycle intermediate facilities. Differences in the size and type of these proposals as well as differences in location will be important to consider as they could change the optimal fuel supply and delivery arrangements that should be required. Since a significant portion of the value of combined cycle intermediate facilities is the ability to generate energy on a much more frequent basis throughout the year, the Company believes it is important that the selected facility have sufficiently firm fuel supply to ensure the ability to operate when the unit will be needed in all twelve months. Many times combined cycle units will be operated as intermediate units with expected capacity factors of 20% or more. This means that the unit is relied upon for energy production more often, and it is more important that it be available to produce energy when dispatched. As a result, the Company typically requires that combined cycle facilities have firm gas transportation arrangements in place unless the project can establish that no interruptions are reasonably expected, or adequate fuel oil back up is available to ensure reliable operation.

The primary value of a peaking unit is to provide energy on the peak usage days and depending upon where the facility is located, the Company believes that interruptible gas transport for peaking units is acceptable during the winter as long as the expected number of interruptions is sufficiently low. However, during summer it will be important for the unit to have very reliable gas supply to ensure that it can be available during the Xcel Energy system's peak periods.

Similar to transmission, when analyzing various bids there is a need to develop and analyze both the cost of interconnecting the proposed project to the interstate natural gas pipeline network and the expected costs of delivering the natural gas over the interstate pipelines. When evaluating the fuel supply plans for natural gas fired generation bids, the Company would typically identify the quantity of natural gas that needs to be delivered to operate the plant at full output. The Company would then contact the natural gas pipeline operators that are in close proximity to the proposed project and determine the availability of firm and interruptible natural gas delivery services on their pipelines, and the associated costs of acquiring those delivery services. The Company may also contact existing shippers on these pipelines to determine the availability and cost of purchasing natural gas delivered to the proposed plant interconnection point as an alternative to acquiring pipeline delivery services directly from the pipeline operator. These natural gas delivery costs would then be assigned to each proposal in the evaluation process.

The Company also undertakes a similar process for proposals that use fuel oil as a secondary fuel. For plants with fuel oil, the Company would determine the amount of fuel oil storage that would need to be installed at the site of the proposed generation, the cost and availability of fuel oil delivery services, and any time restrictions or issues related to accessing additional fuel oil during critical weather events throughout the year. Again, these costs of storage and fuel oil delivery would be added to those specific bids.

*Transmission and Interconnection*

To ensure that each project can deliver the needed capacity to the Xcel Energy system, an evaluation of transmission interconnection plans must be conducted. It may not be necessary for all formal interconnection processes to be completed at the time of project evaluation, however the Commission and evaluators must be reasonably certain that the project will be able connect to the transmission grid on or before the scheduled in-service date, and that the costs of interconnection are reasonably well known and do not pose the threat of substantially changing the cost of the project.

Project evaluators should also gauge the risk of unknown costs associated with transmission network upgrades that may be required by MISO for the project to safely deliver energy to load. Estimates for network upgrade costs can be obtained through studies conducted by MISO or independent consulting firms that run similar models.

*Ancillary Ratepayer Impacts*

It will be important that the Commission's analysis include all of the impacts that can arise from various proposals. Hidden costs and ancillary ratepayer impacts must be included in the analysis to ensure that the overall cost to customers has been adequately identified and internalized.

First, we agree that one of the relevant criteria that should be included is the firmness of the proposed cost of energy. It will be important to understand the potential for additional costs that could be incurred. As noted above, PPA proposals often include price reopeners for unforeseen and unknown costs. These reopeners are a normal part of the negotiations over a PPA and can be appropriate under the circumstances. However, in evaluating a bid based on a "cost cap" it will be important to include the potential for those costs to increase.

Second, in evaluating power purchase alternatives it is important to consider that applicable accounting standards may impute significant costs on the Company that will need to be taken into account.[3] Accounting standards can require that long-term PPAs be treated as leases that must be recognized as debt on the Company's

[3] Accounting guidance requires capital leases to be treated as long-term debt on the Company's balance sheet. Therefore, any PPA that is classified as a capital lease can have a significant impact on the Company's capital structure.

books. Such accounting treatment could have a significant impact on the overall ratepayer cost to the extent it negatively impacts Company's capital structure and increases its cost of financing. This is a very real cost to our customers, although it is incurred indirectly.[4]

We identify this issue for the Commission so it can consider the entire economic impact of the proposals it receives. This impact will need to be incorporated into the evaluation of any PPA alternative in order to fairly compare it to other proposals received. We plan to meet with parties during this proceeding to further explain the capital lease accounting issue and provide examples of the calculation of its cost impacts.

*Flexibility*

Another important criterion for the Commission to consider is the flexibility of proposals to adapt to evolving circumstances. As the Commission knows, demand forecasts have shown considerable variability over the past few years and the forecasting trend is not clear. The Commission can include in its consideration of alternatives the extent to which a particular proposal has flexibility to adapt to changing circumstances.

In the event that the Commission decides that it wants to delay or cancel any part of the generation to meet the identified need, it will be important to understand whether and how the bids received can accommodate such action. It has been the Company's experience that delay is a major concern for independent power developers. Since their projects are usually dependent upon third-party financing, such projects cannot generally support delay without significant financial consequences.

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[4] Auditors will review the rights conveyed to determine whether a particular PPA is classified as a lease. In general, the more control and more risk conveyed to the purchaser (Xcel Energy), the more likely that the agreement will be considered a lease. If a contract is found to be a "lease," the next inquiry will be whether it is an "operating lease" or a "capital lease." Operating lease expenses are recognized much like an actual capacity and energy payment stream over time. In the case of a capital lease, however, the Company's balance sheet would have to show a fixed asset under capital lease and an associated lease obligation that is treated as long term debt. A capital lease is required to be booked as a long term liability on the Company's balance sheet, which increases the long term debt in our capital structure, with potential credit rating implications.

In its analysis of all bids, the Commission should consider the vendors' willingness and ability to defer or cancel portions of their projects as well as the cost incurred to preserve the option to defer or cancel a proposal.

## 2.5 Related Minnesota Filings and Permits

The CT unit the Company is proposing to locate at its Black Dog plant in Burnsville, Minnesota will require several other approvals and permits from the Commission and other state and federal agencies and authorities. These are discussed below.

### 2.5.1 Site and Route Permits

Pursuant to Minn. Stat. § 216E, Subdivision5, the Project's proposal to site a single combustion turbine at Black Dog meets the definition of a large electric power generating plant ("LEPGP") and requires a Site Permit. We plan to file the site permit application by later in the year or early in 2014. There will be additional opportunities for the public to comment on the potential impacts of the Project, and the Department will prepare an environmental assessment and hold a public hearing.

### 2.5.2 Gas Pipeline Routing Permit

The Company will issue a RFP for natural gas transportation. The selected provider will apply for a routing permit if needed in accordance with the requirements of Minnesota Statutes §216G.02 and Minnesota Rules Chapter 7852, as well as any other necessary permits for the gas pipeline construction and operation, such as the general National Pollutant Discharge Elimination System ("NPDES") Stormwater Permit for Construction Activity, if required by the pipeline project's estimated area of disturbance.

### 2.5.3 Environmental Permits

*Air Emission Permit*
We expect to file an application with the Minnesota Pollution Control Agency ("MPCA") in spring 2014 for an amendment to the Black Dog Generating Plant air emission permit, Permit No. 03700003-009, to accommodate the Project.

*NPDES Discharge Permit*
We will apply for an amendment to the plant's existing NPDES discharge permit in 2014 to modify the plant's discharges. Modifications will reduce the amount of

water being discharged from the plant, and these changes need to be incorporated into the existing NPDES permit.

*NPDES Stormwater Program*
The Project triggers the requirement to apply for coverage under the MPCA's NPDES Stormwater Permit Program for Construction Activities. We will prepare a Stormwater Pollution Prevention Plan ("SWPPP"), and apply for coverage under a general permit prior to commencement of Project construction activities. We will require contractors to comply with the SWPPP and the stormwater permit. For existing operations, the plant maintains an Industrial Activity SWPPP as required by the Plant's NPDES permit. Prior to the Project's commercial operation, Xcel Energy will update the Industrial Activity SWPPP as necessary.

### 2.5.4 Other Permits, Approvals, or Notifications

The Project may also require permits, approvals, or notifications under the following programs:

- Federal Aviation Administration Notice of Proposed Construction or Alteration (for exhaust stack and potentially other structures);
- Exemption to allow burning of natural gas for power production (DOE, 10 CFR 503); or
- Miscellaneous State Building and Construction Permits and Inspections (Minn. Stat.; 216E.10, Subd. 2).

We also plan to work closely with local governments and other officials to address any reasonable concerns they might have as we move forward with the Proposal in our site processes.

## 2.6 Related North Dakota Filings and Permits

The two CT units the Company is proposing to locate in the Red River Valley will require several approvals and permits from the North Dakota Public Service Commission and other state and federal agencies and authorities. These are discussed below.

### 2.6.1 North Dakota Resource Acquisition Filings

*Advance Determination of Prudence*

Pursuant to North Dakota Century Code § 49-05-16, a utility may seek an advance determination of the prudence of constructing new generation that will serve North Dakota customers. In its 2007 rate case before the North Dakota Public Service Commission ("PSC"), the Company committed to file for an advance determination of prudence finding by the PSC for any resource acquisition for which it files a certificate of need application with the Minnesota Commission. This commitment is intended to ensure that the PSC is engaged early in the process of reviewing potential resources that could impact the adequacy and cost of the Company's service in North Dakota. Pursuant to its commitment, the Company will seek an ADP finding by the PSC that the Company's proposal to add three CTs to its system in the 2017-19 time period is prudent.

*Certificate of Public Convenience and Necessity*

Pursuant to North Dakota Century Code § 49-03-01.1 provides that no electric public utility may construct, operate or extend public utility plant or system without first obtaining a certificate from the PSC that public convenience and necessity (CPCN) does or will require the proposed construction, operation, or extension. The Company will jointly apply for a CPCN for its Proposal with the ADP application discussed above.

### 2.6.2 Certificate of Site and Corridor Compatibility, and Route Permit

Pursuant to Section 49-22-07 of the North Dakota Century Code, a utility may not begin construction of generation plant or transmission facilities without first obtaining a certificate of site or corridor compatibility. In addition to the certificate of compatibility designating a corridor for transmission facilities, the utility must obtain a route permit for the facilities within the designated corridor. The Company would obtain these required certificates and route permit upon receiving a CPCN from the PSC for its Proposal.

### 2.6.3 Environmental Permits

*Air Emission Permit*

The Company must apply for an Air Emission Permit from the North Dakota Department of Health ("NDDoH") no later than 18 months before the start of construction. Based on a spring 2018 in service date, permitting would begin in 2014. The permit application would likely fall into the Prevention of Significant Deterioration ("PSD") category for one or more pollutants. The PSD Permit application would require an Ambient Air Quality Analysis, a Best Available Control Technology ("BACT") Analysis, and an Additional Impacts Analysis. The Ambient Air Quality Analysis would evaluate the project's impact on National Ambient Air Quality Standards ("NAAQS"), and would include a PSD increment analysis. Lastly, a State Air Toxics Analysis will need to be performed to support the Proposal.

*NPDES Stormwater Program*
The Project triggers the requirement to apply for coverage under the NDDoH's Construction Stormwater Permit Program. We will prepare a Stormwater Pollution Prevention Plan ("SWPPP") and apply for coverage under a general permit prior to commencement of Project construction activities. We will require contractors to comply with the SWPPP and the stormwater permit.
Prior to the Project's commercial operation, Xcel Energy will obtain an Industrial Permit under the Stormwater program as necessary.

*Section 404 Wetland Permit*
The Project will evaluate whether any wetlands are impacted to determine if any mitigation is needed.

### 2.6.4 Other Permits, Approvals or Notifications

The Project may also require permits, approvals, or notifications under the following programs:

- Federal Aviation Administration Notice of Proposed Construction (for exhaust stack and potentially other structures);
- ND Department of Health Crossing Permits for Associated Utilities (e.g. electric transmission lines, natural gas lines, sewer lines) by Xcel Energy or the provider of the utility;
- Floodplain Work Approval through Site Permitting;
- Exemption to allow burning of natural gas for power production (DOE, 10 CFR 503);
- Endangered Species Act Review; and
- Surface and/or groundwater appropriations permitting.

We also plan to work closely with local governments and other officials to address any reasonable concerns they might have as we move forward with the Project in our Site processes.

# 3 Resource Need

This Competitive Acquisition Process is designed to select the appropriate generation resource to meet the capacity need identified in the Company's 2011-2025 Resource Plan. Following a lengthy collaborative process with the Company and various stakeholders, the Commission found that the record demonstrated a need for an additional 150 MW of firm capacity by 2017, with that need increasing up to 500 MW by 2019. In this section we discuss:

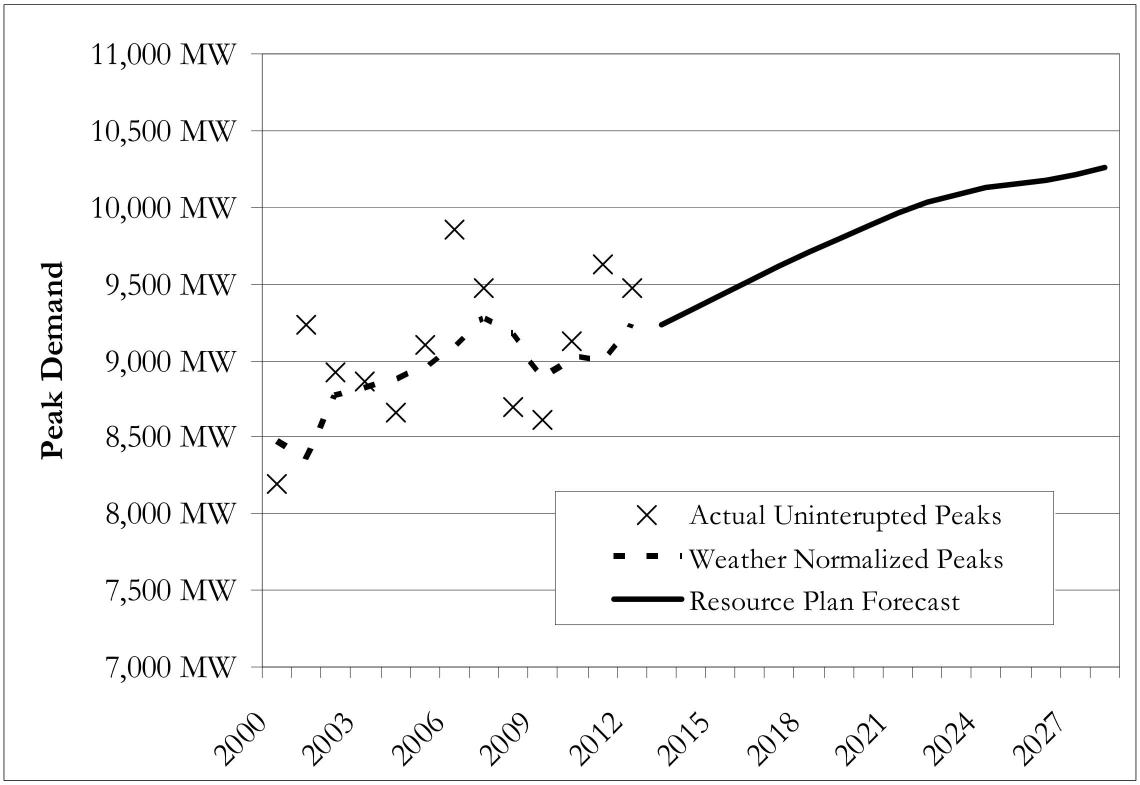
- *Identified Resource Need*- summarizing the inputs and factors that determined the level of need identified in our Resource Plan proceeding;
- *Forecast Uncertainty*- discussing two factors that contribute to uncertainty around our system resource needs – peak demand forecast variability and MISO reserve margin policy – and describing how our proposal provides the flexibility to address this uncertainty.

## 3.1 Identified Resource Need

In our last Resource Plan proceeding, the size and timing of the next generation resource needed on our system was based on the Company's forecast peak demand and required system reserves compared to the existing resources available to meet this peak demand and reserve requirements.

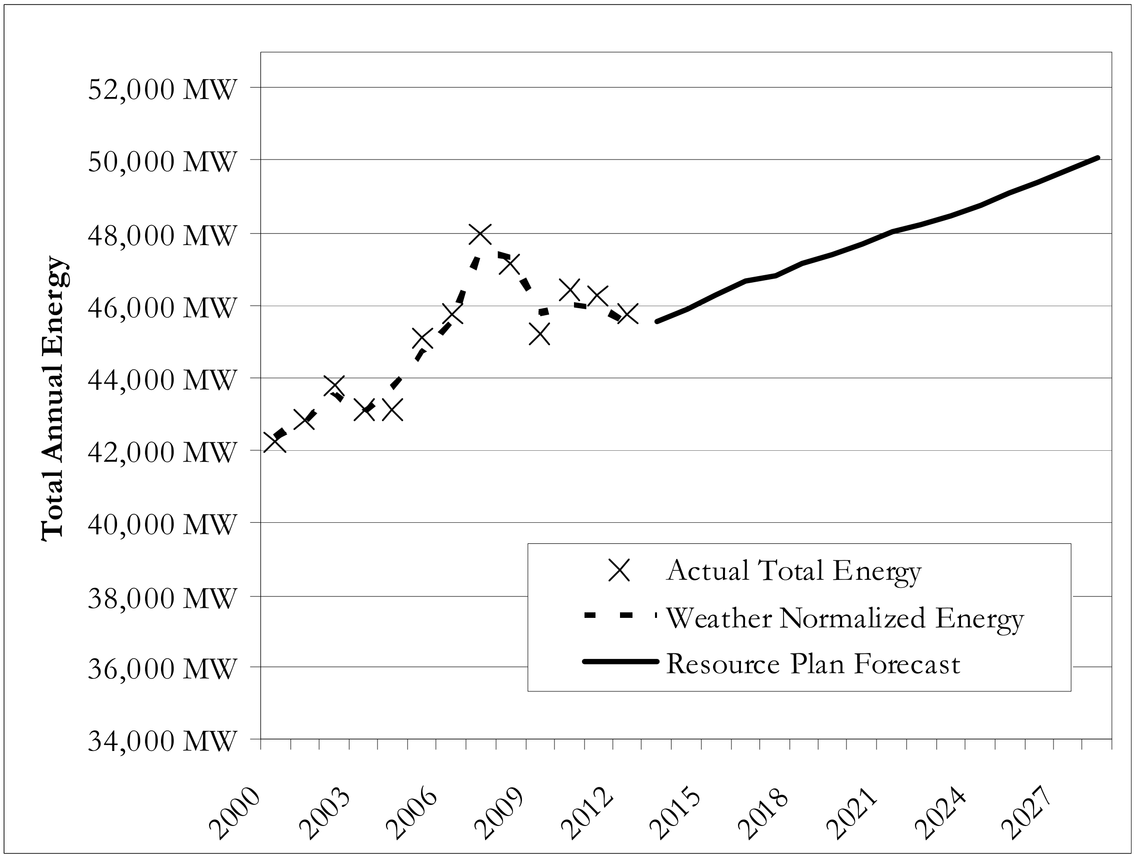
The assessment of resource need is based on three primary factors: peak demand forecast; reserve margins; and the maximum generation capability of existing resources. The load forecast used to establish the need approved by the Commission was the Company's Fall 2011 forecast, presented as an update to the forecast filed in our initial Resource Plan filing. The Fall 2011 update reflected a large downward shift in expected customer demand as a result of the ongoing effects of the economic recession. After thorough review of our forecast model, the Department recommended a small adjustment to our peak demand forecast (30 MW-40 MW). Figure 3-1 shows the peak demand forecast, including the Department's recommended adjustment, that was used to support the identified resource need in this proceeding. From 2013 through 2020, the average rate of growth in our peak demand forecast is 1.0 percent.

**Figure 3-1**
**NSP Historic and Forecasted Peak Demand**




In addition to updating our peak demand forecast in our Resource Plan proceeding, we also updated our forecast of total annual energy requirements (sales plus transmission losses). While total annual energy is not a critical input when assessing capacity need, it can be a factor when assessing the best type of resource to build. Our total annual energy forecast, shown in Figure 3-2, also reflects the effect of the economic recession. The average growth rate from 2013 to 2020 is 0.7 percent.

**Figure 3-2**
**NSP Historic and Forecasts Total Annual Energy**




Our peak demand and energy forecasts include the impact of the Company's on-going demand side management (DSM) efforts. Additional information on the methodology used to develop the demand forecast, and other forecast details required by Minn. Rule 7849.0270, is provided in Appendix A. Additional information on DSM is provided in Appendix B.

In the Resource Plan proceeding, parties agreed it was appropriate to use the reserve margin calculations specified by MISO. Under FERC rules, MISO has been given the responsibility of establishing planning reserve margins to ensure reliable operation of the bulk power generation system. MISO has recently adopted a new reserve margin methodology based on unforced capacity (UCAP) calculations. This approach reduces the capacity rating of each generating resource by its recent forced outage rate, and uses a relatively small reserve margin to cover other potential contingencies. In our Resources Plan proceeding, conversion of our resource capacities to the UCAP rating resulted in a reduction of approximately 700 MW. Based on historic operating performance, we continue to expect our plants to operate at full capacity on peak summer days, thus this methodology essentially builds in a 700 MW reserve margin to our system planning.

Due to the implicit reserve margin resulting from use of the UCAP methodology, MISO is able to specify a lower reserve margin percentage to apply to the forecasted peak demand. MISO calculates the reserve margin percentage based on loss of load expectation (LOLE) studies that calculate how high the reserve margin must be to ensure that load will not have to be curtailed any more often than once in every ten years. In our Resource Plan we used a reserve margin of 3.79 percent, based on a LOLE study conducted by MISO in the Spring of 2011.

Table 3-1 shows how the reserve margin percentage is translated into MWs on our system. This table also illustrates that when the reserve margin is combined with the implicit reserve of 700 MW due to the UCAP adjustment, the NSP system has a reserve capacity of approximately 1000 MW, or 10 percent of forecasted peak demand in 2017-2019. This reserve margin is considerably lower than the 15 percent reserve margin that was required by MAPP before MISO became the entity responsible for regional system reliability.

**Table 3-1**
**Total System Reserves**

| | 2017 | 2018 | 2019 |
|---|---|---|---|
| Peak Forecast | 9,613 MW | 9,708 MW | 9,799 MW |
| x Reserve Margin | x 3.79% | x 3.79% | x 3.79% |
| = Required Reserves | 364 MW | 368 MW | 371 MW |
| + Implicit Reserves From UCAP Adjustment | 714 MW | 696 MW | 700 MW |
| = Total Reserves | 1,079 MW | 1,064 MW | 1,071 MW |
| *Equivalent Reserve Margin %* | *10.1%* | *9.9%* | *9.8%* |

Comparing the load forecast plus reserve margin to the capacity ratings of NSP-owned resources plus purchased power, our system's forecasted capacity need is approximately 500 MW by 2019, as shown in Table 3-2.

**Table 3-2**
**System Capacity Need**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Peak Forecast | 9,428 | 9,524 | 9,613 | 9,708 | 9,799 | 9,881 |
| x 1+RM% | 3.8% | 3.8% | 3.8% | 3.8% | 3.8% | 3.8% |
| = Total Obligation | 9,786 | 9,885 | 9,977 | 10,076 | 10,170 | 10,255 |
| | | | | | | |
| **Resources** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| Coal | 2,331 | 2,331 | 2,331 | 2,331 | 2,331 | 2,331 |
| Nuclear | 1,610 | 1,610 | 1,610 | 1,610 | 1,610 | 1,610 |
| Gas | 3,476 | 3,534 | 3,437 | 3,424 | 3,424 | 3,424 |
| Renewable | 1,288 | 1,289 | 1,287 | 1,238 | 1,212 | 1,213 |
| Other | 92 | - | - | - | - | - |
| Load Management* | 1,145 | 1,153 | 1,157 | 1,153 | 1,149 | 1,145 |
| Total | 9,943 | 9,917 | 9,823 | 9,757 | 9,727 | 9,724 |
| | | | | | | |
| **Long (Short)** | **157** | **32** | **(154)** | **(319)** | **(443)** | **(532)** |

* Includes reserves

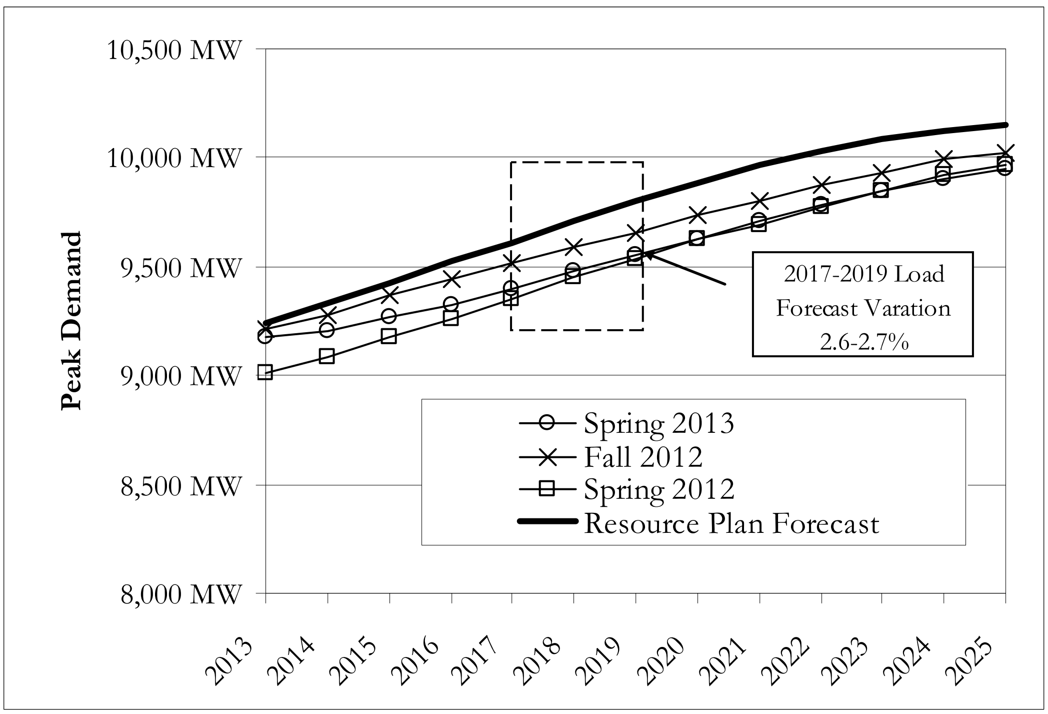
## 3.2 Forecast Uncertainty

There are two principal factors contributing to uncertainty around the assessment of generating capacity requirements. The first is variability of the peak demand forecast, and the second is MISO's changing reserve margin standards. While both of these factors have changed since the final analysis was completed in our Resource Plan proceeding, we continue to believe it is appropriate to use the capacity need targets identified in the Resource Plan, and our proposal is designed to meet that resource need. This conservative approach is reasonable and will ensure reliable service for our customers for the remainder of this decade. However, we believe a discussion of this inherent forecast uncertainty is appropriate. Our proposal also provides the Commission with the flexibility to defer or cancel one or more of the components of our project based on future circumstances.

### 3.2.1 Forecast Variability

Peak demand forecasts are dependent on underlying assumptions regarding economic growth, which have become more uncertain since the recent recession. The Company's varying forecasts over the course of the Resource Plan proceeding demonstrate this. Relatively small changes in economic growth rate assumptions have resulted in our peak demand estimates varying by several hundred MWs in the 2017 – 2019 timeframe. The variation in our load forecast does not have a clear upward or downward trend and the amount of variation is relatively small in the context of our total system peak demand. Since the Fall of 2011, when the last Resource Plan analysis was completed, the Company has updated its forecast three times. The total variation in forecasts has only been about 250 MW, or 2.6 percent, in the 2017 – 2019 timeframe. Figure 3-3 shows the peak demand forecast changes.

**Figure 3-3**
**Variation in Peak Demand Forecasts**




These relatively small variations in our forecast are primarily a reflection of the inherent uncertainty in forecasting, and we do not believe there is currently any indication of a definitive change in the future peak demand of our customers. Under these circumstances, we believe a conservative approach in this resource acquisition process is warranted to ensure adequate generating capacity for our customers. While small changes in forecasts would not affect generating resource additions planned for the 2017-2019 timeframe, our proposal does provide flexibility that would allow the Commission to adjust any decision based on future circumstances that may have a greater impact on customer demand.

### 3.2.2 MISO Reserve Margin Policy

MISO establishes the resource adequacy margin that load-serving entities, such as Xcel Energy, must meet each summer season. The reserve margin for the Summer of 2012, which was used in our Resource Plan proceeding, was 3.8 percent.

MISO updates its required reserve margin annually by conducting a loss of load expectation study. This study estimates the amount of reserves needed to ensure that load will only be curtailed once every ten years. Based on the LOLE study completed in November 2012, the reserve margin for 2013 is 6.2 percent. This results in approximately 240 MW of additional reserve capacity that must be maintained on our system.

In addition to the new reserve margin calculation based on the new LOLE study, MISO has changed its reserve margin methodology for the Summer of 2013. Instead of basing reserve margin calculations on each utility's peak load, utilities are now required to forecast their system load at the time of MISO's total system peak. To the extent that the Company's peak does not coincide with MISO's peak, our total capacity obligation will be lower. Since 2005, our peak has not coincided with the MISO peak in five of the eight summer seasons. Table 3-3 shows that on average, our load was 5 percent lower than our peak at the time MISO's total system reached its peak.

**Table 3-3**
**NSP and MISO Peak Demand**

| Year | NSP Load at Time of MISO Peak | NSP Peak Load | Difference | Coincidence Factor | Diversity Factor |
|---|---|---|---|---|---|
| 2005 | 8,457MW | 9,104MW | -647MW | 93% | **7%** |
| 2006 | 9,855MW | 9,859MW | -4MW | 100% | **0%** |
| 2007 | 8,184MW | 9,473MW | -1,289MW | 86% | **14%** |
| 2008 | 8,678MW | 8,694MW | -16MW | 100% | **0%** |
| 2009 | 7,975MW | 8,609MW | -634MW | 93% | **7%** |
| 2010 | 8,463MW | 9,131MW | -668MW | 93% | **7%** |
| 2011 | 9,621MW | 9,623MW | -2MW | 100% | **0%** |
| 2012 | 8,796MW | 9,475MW | -679MW | 93% | **7%** |
| | | | | Average | **5%** |

For the Summer of 2013 NSP used this five percent diversity factor when filling our summer adequacy plans with MISO. However, it is unknown if this load diversity will continue in the future or if this standard will continue to be used by MISO.

MISO also annually adjusts the MW level at which generation units are given credit when assessing total reserve margin. As previously discussed, this UCAP adjustment is based on each unit's recent reliability statistics. The UCAP rating of most of our units changed only slightly from 2012 to 2013. However our A.S. King plant has performed well, and its accredited capacity increased by 33 MW – from 477 MW to 510 MW.

Tables 3-4, 3-5, and 3-6 compare the resource need as identified in the Resource Plan proceeding to updated need assessments based on our most recent load forecast and MISO's 2013 reserve margin requirements. We show the updated need forecast with and without the 5 percent diversity factor to illustrate the impact that this may have on our resource need requirements.

**Table 3-4**
**2011 - 2025 NSP Resource Plan**

| | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|---|
| Peak | 9,428 | 9,524 | 9,613 | 9,708 | 9,799 | 9,881 |
| RM% | 3.8% | 3.8% | 3.8% | 3.8% | 3.8% | 3.8% |
| Total Obligation | 9,786 | 9,885 | 9,977 | 10,076 | 10,170 | 10,255 |
| **Resources** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| Coal | 2,331 | 2,331 | 2,331 | 2,331 | 2,331 | 2,331 |
| Nuclear | 1,610 | 1,610 | 1,610 | 1,610 | 1,610 | 1,610 |
| Gas | 3,476 | 3,534 | 3,437 | 3,424 | 3,424 | 3,424 |
| Renewable | 1,288 | 1,289 | 1,287 | 1,238 | 1,212 | 1,213 |
| Other | 92 | - | - | - | - | - |
| Load Management* | 1,145 | 1,153 | 1,157 | 1,153 | 1,149 | 1,145 |
| Total | 9,943 | 9,917 | 9,823 | 9,757 | 9,727 | 9,724 |
| **Long (Short)** | **157** | **32** | **(154)** | **(319)** | **(443)** | **(532)** |

* Includes reserves

**Table 3-5**
**Spring 2013 Update - 5% Diversity Factor**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Peak | 9,264 | 9,326 | 9,401 | 9,477 | 9,549 | 9,629 |
| MISO Coincidence | 5% | 5% | 5% | 5% | 5% | 5% |
| Coincident Peak | 8,801 | 8,860 | 8,931 | 9,003 | 9,071 | 9,148 |
| RM% | 6.1% | 6.1% | 6.0% | 6.0% | 6.0% | 6.0% |
| Total Obligation | 9,338 | 9,400 | 9,467 | 9,543 | 9,616 | 9,696 |
| *Effective RM%* | *0.8%* | *0.8%* | *0.7%* | *0.7%* | *0.7%* | *0.7%* |
| **Resources** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| Coal | 2,368 | 2,368 | 2,368 | 2,368 | 2,368 | 2,368 |
| Nuclear | 1,625 | 1,625 | 1,625 | 1,625 | 1,625 | 1,625 |
| Gas | 3,457 | 3,513 | 3,431 | 3,420 | 3,420 | 3,420 |
| Renewable | 1,280 | 1,280 | 1,277 | 1,229 | 1,219 | 1,218 |
| Other | 66 | (29) | (25) | - | - | - |
| Load Management* | 1,093 | 1,102 | 1,113 | 1,124 | 1,135 | 1,146 |
| Total | 9,889 | 9,860 | 9,790 | 9,767 | 9,767 | 9,777 |
| **Long (Short)** | **552** | **460** | **323** | **223** | **151** | **81** |

**Table 3-6**
**Spring 2013 Update - 0% Diversity Factor**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Peak | 9,264 | 9,326 | 9,401 | 9,477 | 9,549 | 9,629 |
| MISO Coincidence | 0% | 0% | 0% | 0% | 0% | 0% |
| Coincident Peak | 9,264 | 9,326 | 9,401 | 9,477 | 9,549 | 9,629 |
| RM% | 6.1% | 6.1% | 6.0% | 6.0% | 6.0% | 6.0% |
| Total Obligation | 9,829 | 9,895 | 9,965 | 10,046 | 10,122 | 10,207 |
| **Resources** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| Coal | 2,368 | 2,368 | 2,368 | 2,368 | 2,368 | 2,368 |
| Nuclear | 1,625 | 1,625 | 1,625 | 1,625 | 1,625 | 1,625 |
| Gas | 3,457 | 3,513 | 3,431 | 3,420 | 3,420 | 3,420 |
| Renewable | 1,280 | 1,280 | 1,277 | 1,229 | 1,219 | 1,218 |
| Other | 66 | (29) | (25) | - | - | - |
| Load Management* | 1,093 | 1,102 | 1,113 | 1,124 | 1,135 | 1,146 |
| Total | 9,889 | 9,860 | 9,790 | 9,767 | 9,767 | 9,777 |
| **Long (Short)** | **60** | **(35)** | **(176)** | **(279)** | **(355)** | **(429)** |

The Company believes the prudent approach is to plan to meet the current identified need on our system. This conservative approach ensures adequate generating capacity under all reasonable circumstances. At the same time, the Commission can consider options that provide flexibility to adjust the timing of resource additions. Our proposal to construct three CT generating units sequentially in 2017, 2018, and 2019 represents such an approach. In the event that Xcel Energy's proposal is selected, we offer the Commission the option of altering the in-service date or canceling one or more of our proposed units to best match the growth in customer demand while minimizing rate impacts for our customer.

# 4 Project Description

The Company proposes to install three natural gas fueled, simple cycle, combustion turbine generators. Each unit can produce approximately 215 MW of power in summer heat and humidity conditions. We propose to deploy the new generation as follows:

- **Black Dog Unit 6:** The first 215 MW combustion turbine would be placed in service in 2017 at the Company's existing Black Dog plant in Burnsville. The unit would substantially replace the coal fired generating capacity at this existing site, which is scheduled to retire in 2015. The Black Dog plant site allows the Company to maximize the use of existing infrastructure to maintain generation within our largest load center, which enhances operating reliability.
- **Red River Valley Unit 1 ("RRV 1"):** The second 215 MW combustion turbine and associated natural gas pipeline, transmission, and interconnection facilities would be placed in service in 2018 at a new site in the general vicinity of Hankinson, North Dakota. This unit would enhance geographic diversity in our supply portfolio, and would enhance operating reliability by placing new generation in a fast-growing part of our system.[1]
- **Red River Valley Unit 2 ("RRV 2")**: The third 215 MW combustion turbine would be placed in service in 2019 and added to the plant site established for RRV 1. Alternatively, Xcel Energy could deploy RRV 1 and RRV 2 together in either 2018 or 2019. Simultaneous construction, as a single project instead of two, would result in savings of about $4 million if constructed in 2018.

## 4.1 Project Overview

A simple cycle combustion turbine is an electric generating technology in which electricity is produced from a combustion turbine without incorporating heat recovery from the turbine exhaust. A schematic of a single combustion turbine at Black Dog is shown below in Figure 4-1. A schematic of two combustion turbine units at the North Dakota site is shown in Figure 4-2.

[1] Xcel Energy is concurrently seeking the approval of the North Dakota Public Utilities Commission for the two units to be located in the Red River Valley.

**Figure 4-1**
**Schematic Diagram of a 1 Unit Simple Cycle Facility – Black Dog**

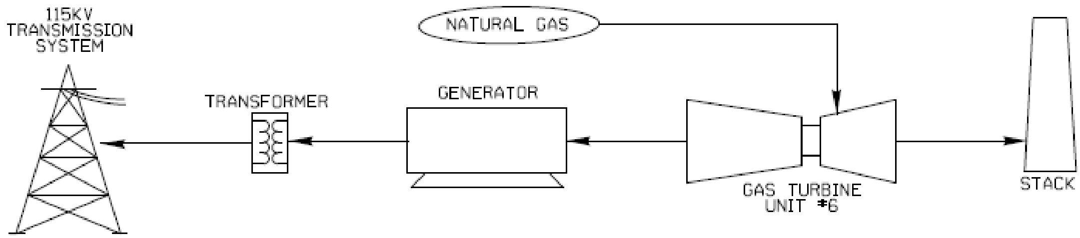
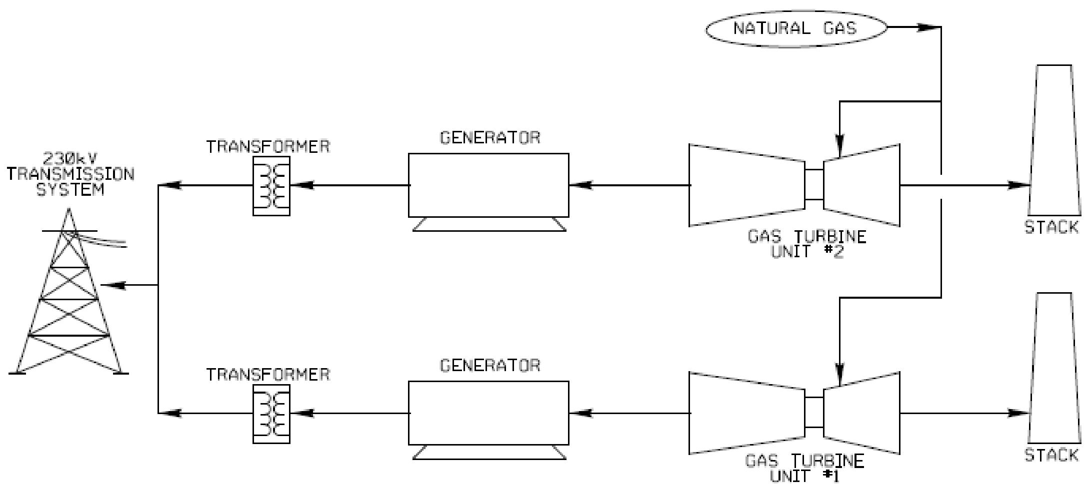



**Figure 4-2**
**Schematic Diagram of a 2 Unit Simple Cycle Facility – North Dakota**




The design capacity of the Project is based on the performance characteristics of F class combustion turbines. The combustion turbine technology available today is significantly improved over that available even a few years ago. The model of F class combustion turbines now commercially available has fast start capability, which allows it to reach 150MW in 10 minutes from a cold start, operate in a range of at least 50 to 100% load while meeting emission limits, and achieve faster ramp rates over the load range. In addition, the maintenance and overhaul cycles have been significantly improved. The base performance, with respect to full load capacity and heat rate, has also been improved.

Each combustion turbine-generator consists of the following equipment in series:

1. Inlet Air Filter and evaporative cooler, which cleans and cools the air entering the turbine;
2. Compressor, where air is drawn in and compressed;
3. Combustor, where the air/fuel mixture is ignited;
4. Power Turbine, where the combusted gases expand to rotate a turbine-generator;
5. Generator, which converts the rotating mechanical energy to electrical energy;
6. Main Step-Up transformer, which increases the generator voltage to the transmission voltage of either 115kV or 230kV; and
7. Auxiliary Transformer, which converts some of the output power to lower voltages for use by the Unit's auxiliary equipment.

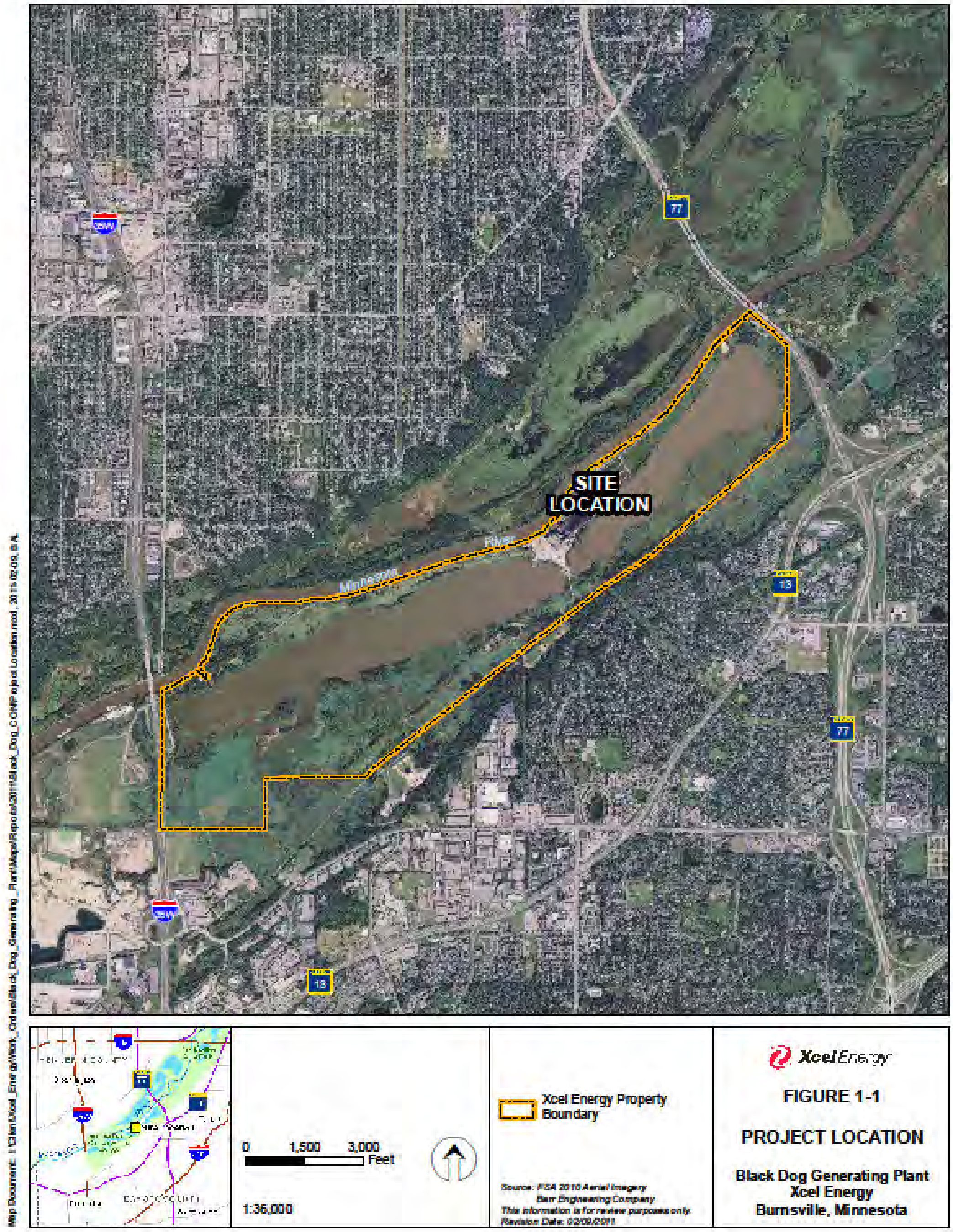
The combustion turbine units will be integrated into our remote dispatch control center. We expect to use the units for peaking load service, dispatching them after all lower cost and "must run" units. They are expected to be dispatched primarily during higher system load periods in the summer and winter months, with an annual capacity factor of between four and ten percent.

The units will also serve to load follow as system load requirements change. They will be able to provide capacity of 150 MW within a 10-minute notice (qualifying the units for spinning reserve status within MISO), and will have the ability to ramp at a minimum of 15 MW per minute.

## 4.2 Black Dog Unit 6

Black Dog Unit 6 will be located at the Black Dog plant in Burnsville, Minnesota, approximately 15 miles south of Minneapolis and east of the City of Eagan (see Figure 4-3). The Black Dog plant is currently a coal- and gas-fired generating station.

**Figure 4-3**
**Black Dog Plant Site**

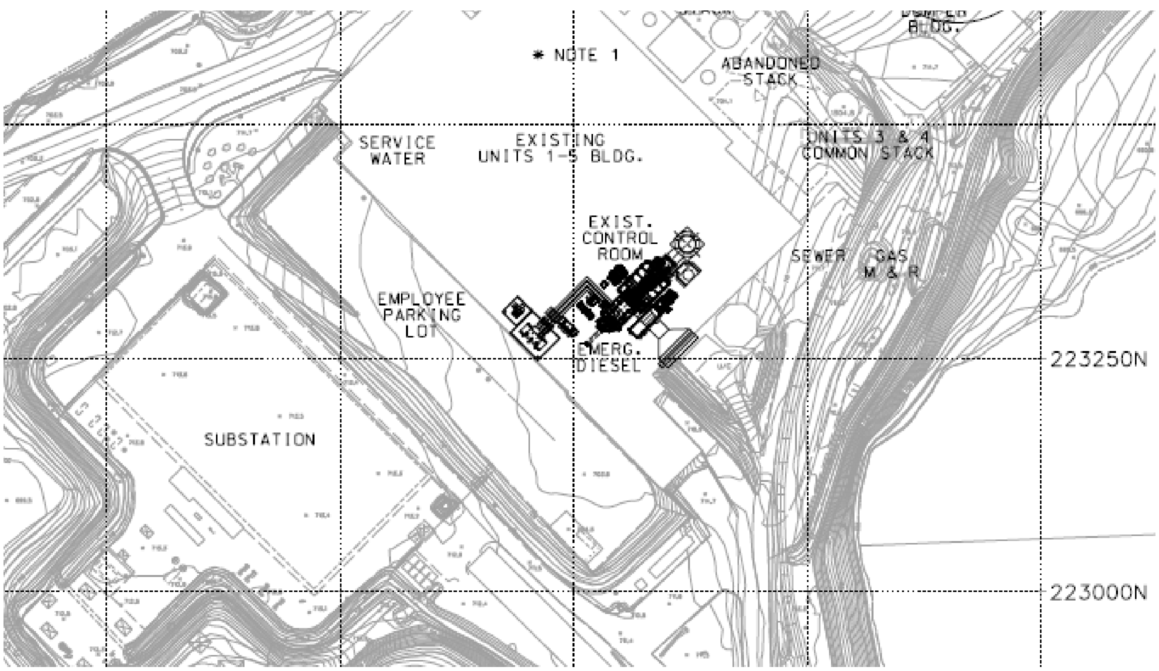



The original Unit 1 boiler/turbine and the Unit 2 boiler, installed at the site in the 1950s and fired on coal, were repowered with a natural gas combined-cycle unit (Unit 5), which includes a natural gas combustion turbine-generator combined with a heat recovery steam generator that delivers steam to the Unit 2 steam turbine and generator. The repowering project, completed in summer 2002, increased output from the two original units by more than 100 MW, and resulted in greater operating efficiency and cleaner power production.

Black Dog Units 3 and 4, which utilize coal as the primary fuel, were put into service in 1955 and 1960. The boilers, turbines and generators are essentially original equipment which have been well maintained and operated. However, operating data shows a declining availability as the units continue to age. After examining the costs necessary to continue to operate these units reliably, and the cost of the pollution controls that will be needed for continued operation, our current plan is to retire the units in 2015. Accordingly, the resource need identified by the Commission in this proceeding assumes Units 3 and 4 will be retired in 2015.

Black Dog Unit 6 will be located in the existing powerhouse, in the area where Unit 4 currently is located. The proposed layout for Unit 6 inside the existing building is shown in Figure 4-4.

**Figure 4-4**
**Project Layout**



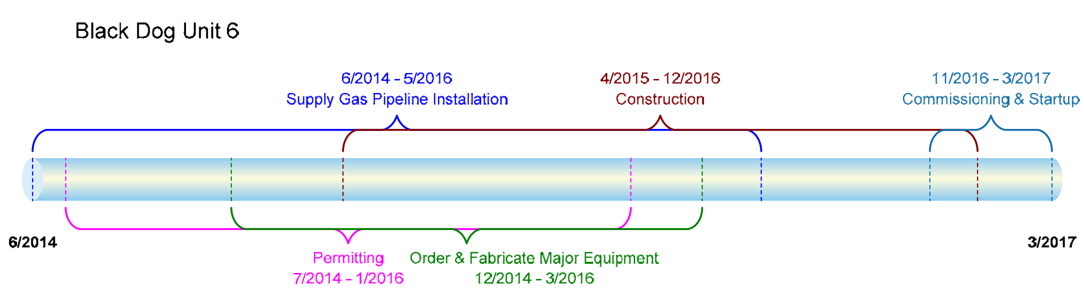

The exhaust stack will be approximately 200 feet tall and located adjacent to Unit 6, in the area of the existing Unit 4 boiler. The new unit will be connected to the existing 115 kV substation. Minor modifications to the existing 115kV switchyard will be required to connect it to the transmission system. No upgrades of the 115 kV transmission system are required since Unit 6 will utilize some of the outlet capacity from retired Units 3 and 4, and a new interconnection request with MISO is not required.

The output of Black Dog Unit 6 depends on ambient weather conditions (primarily temperature and humidity), and altitude. For purposes of this application, nominal generating capacity is considered to be about 215 MW at Summer ambient conditions of 95F and relative humidity of 30 percent, with an altitude of 720 feet above sea level.

Unit 6 will be fueled entirely by natural gas. CenterPoint Energy currently serves the plant site. We will be securing additional natural gas supply through a competitive process beginning in early 2014. We anticipate that the successful bidder may need to file for a route permit and other necessary permits to replace the existing pipeline serving the plant with a new higher pressure natural gas line running from the Cedar Town Border station to the plant.

Generation block construction will begin after site permit and other approvals are obtained. Decommissioning, demolition, and removal of the Unit 4 turbine, generator, boiler and other components will be completed prior to constructing Unit 6. In order to allow the construction of Unit 6 to begin when needed, it will be necessary to take Unit 4 out of service in September 2014. Unit 6 will be constructed in 2015 and 2016. See Figure 4-5 below. Start-up of the unit would occur in early 2017. Unit 6 is expected to be in commercial operation late in the 1st quarter of 2017.

**Figure 4-5**
**Black Dog Unit 6 Construction Schedule**




The capital cost estimate for Black Dog Unit 6, as well as performance and operation and maintenance information, is presented in Appendix C.
Figure 4-6 provides a preliminary artist's rendering of what the Black Dog plant site will look like after installation of Black Dog Unit 6.

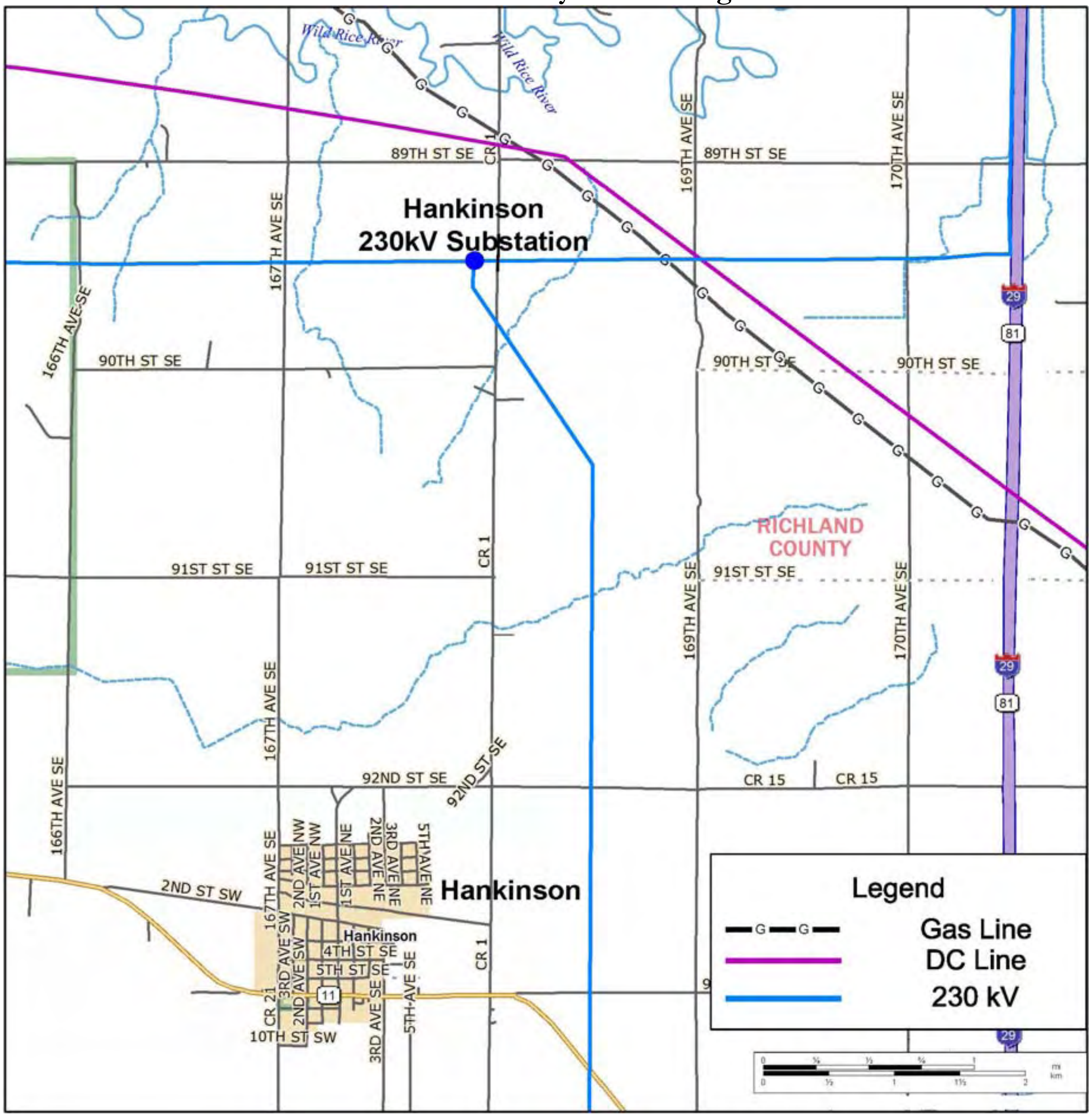
**Figure 4-6**
**Black Dog Plant Rendering**

Unit 6 will be operated and maintained by the staff that will be retained for Units 2 and 5 (the existing 1X1 combined cycle facility) after the retirement of Units 3 and 4. No additional staff are planned to accommodate the new unit. It will be operated as a peaking generator with an anticipated annual capacity factor of 4 to 10 percent. The service life of Unit 6 is anticipated to be in excess of 35 years. Annual availability will be greater than 95 percent.

## 4.3 Red River Valley Units 1 and 2

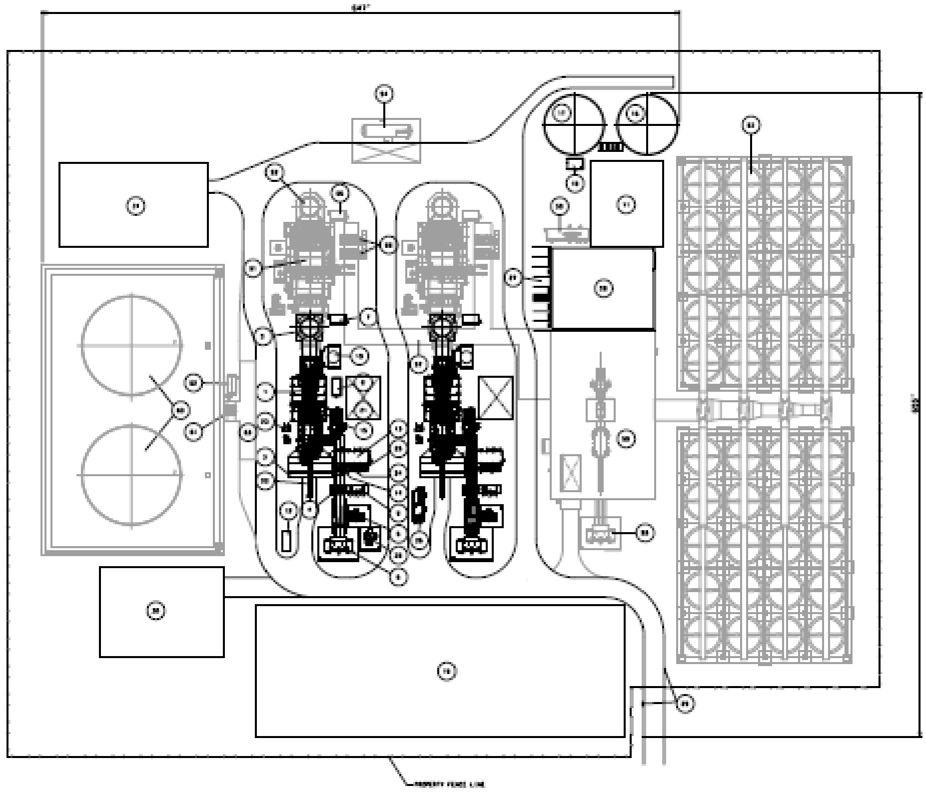
A specific plant site for the two Red River Valley units in southeast North Dakota has not been selected at this time. We anticipate the facility will be located in the general vicinity of Hankinson, North Dakota. The area provides access to the 230 kV transmission system serving the region and is near a major natural gas pipeline. Approximately 160 acres are anticipated to be obtained. Figure 4-6 illustrates the area under consideration in the southeast corner of North Dakota.

**Figure 4-7**
**Red River Valley Plant Siting Area**




The proposed facility would consist of two, 215 MW combustion turbines with the necessary infrastructure to accommodate a full time operating and maintenance staff. The layout of the facility allows for two combustion turbines to be installed, and can accommodate conversion to combined cycle configuration in the future. A preliminary layout for two combustion turbines is shown in Figure 4-7.

**Figure 4-8**
**Potential Layout of Red River Valley Facility**



It is anticipated that the tallest structure within the plant will be the stacks, at approximately 65 feet. The combustion turbines and building are all expected to be less than 40 feet in height.

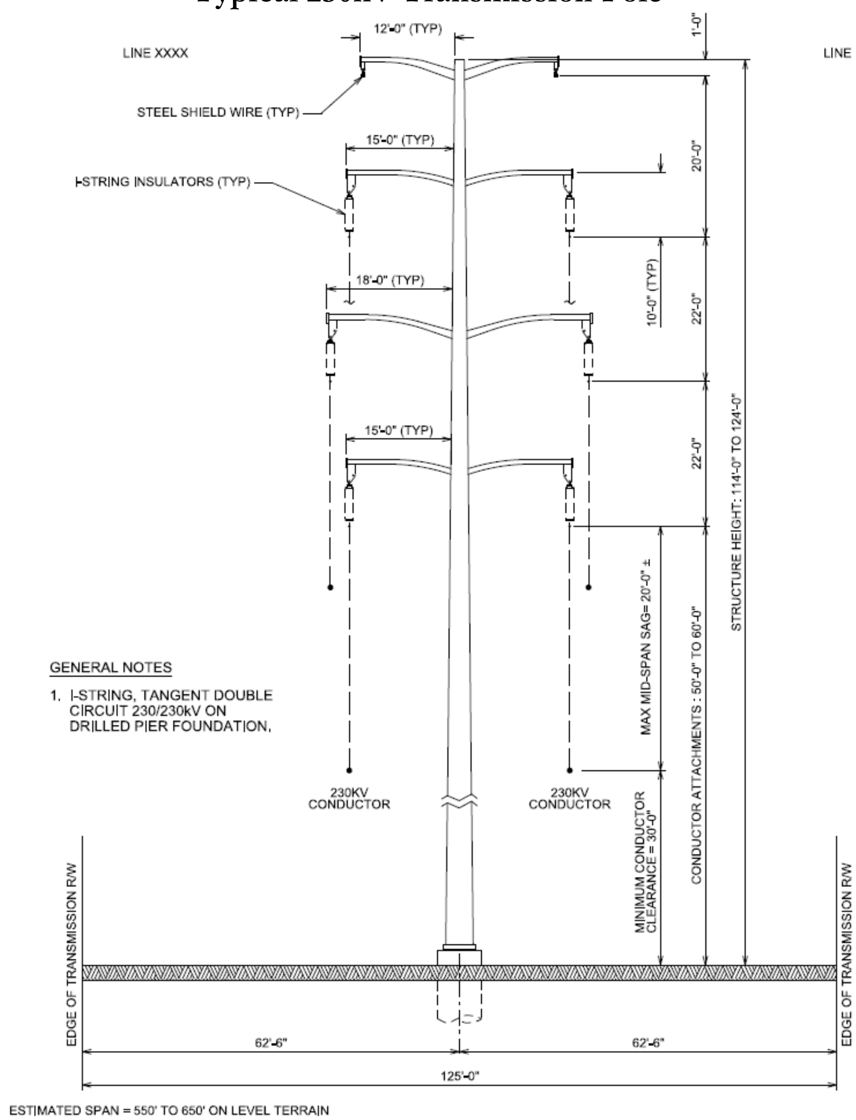
The output of the units depends on ambient weather conditions (primarily temperature and humidity). For purposes of this application, nominal generating capacity is considered to be about 214 MW at Summer ambient conditions of 88F and relative humidity of 42 percent, with an altitude of 900 feet above sea level. The combustion turbines will utilize natural gas as its fuel. The layout of the facility allows for addition of distillate oil storage and handling if a future need develops to have oil as the backup fuel. The Hankinson siting area is near the Alliance interstate gas pipeline. Multiple parties utilize this line to transport gas, and indicated a willingness and ability to provide gas service. We anticipate securing the necessary natural gas supply through a competitive process beginning in 2014. Water supply will either be from an on-site well or provided by truck.

The Red River Valley plant would connect to the transmission network by either expanding the existing Otter Tail Power Hankinson 230kV substation or building a new 230 kV substation at another location. We anticipate a new double circuit

230 kV line will connect the plant to the interconnection substation and transmission system.

We anticipate the structures for the 230 kV double circuit line would be about 115 to 125 feet tall, and would have an average span between 550 and 650 feet. The finish of the proposed poles would be galvanized steel. The conductor would be 477 kcmil ACSR 26/7 (Hawk), with an approximate 330 MW summer rating for each circuit. Equivalent bundled twisted pair ACSR conductor may be used if the area is prone to galloping conductors. Figure 4-9 below is an illustration of a typical 230 kV structure.

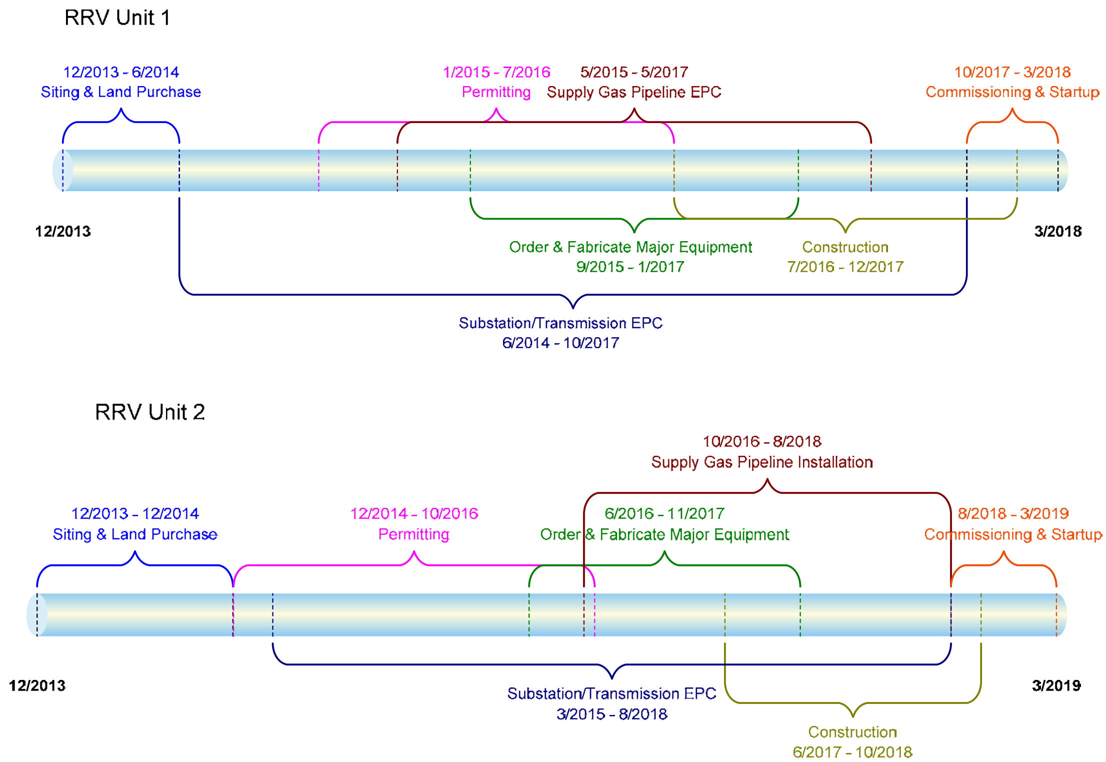
**Figure 4-9**
**Typical 230kV Transmission Pole**



The Company has identified the likely transmission upgrades needed to interconnect the peaking generation at the Red River Valley site through a preliminary generation interconnection study. The study indicated that two system upgrades may be required to support interconnection: 1) the completion of the Big Stone – Brookings County 345 kV transmission line; and 2) rebuilding the existing Hankinson – Wahpeton 230 kV line. Our study work indicates that the Hankinson - Wahpeton rebuild will be necessary to support interconnection of the second generating unit. The Big Stone – Brookings County line is currently being permitted in South Dakota, and is planned to be in-service by the end of 2017. The Red River Valley plant would not be responsible for any of this line cost since it is part of the MISO MVP portfolio of regional transmission improvements. Arrangements for the Hankinson – Wahpeton line to be rebuilt would be through the MISO generator interconnection process.

In order to place one or both Red River Valley units in operation in early 2018, a number of activities need to begin in 2014. See Figure 4-10 below. These activities include acquiring land or land options and gas pipeline and transmission line rights of way; environmental assessment of the plant site; permit development and application; and requesting a transmission interconnection study and agreement. In 2015, preliminary design would begin and procurement of major equipment would be completed. Site construction would start in mid-2016, and be completed in late 2017.

**Figure 4-10**
**Potential Construction Schedule Red River Valley Units 1 and 2**




The capital cost of Red River Valley Units 1 and 2, along with performance and operations and maintenance information, are presented in Appendix C. We have also provided conservative indicative cost estimates for the anticipated gas pipeline interconnection, the transmission facilities to connect the plant to the transmission system, and the 230 kV network upgrade.

The new Red River Valley plant will be operated and maintained by a full time staff located at the plant site, primarily for day shift operation. The unit(s) will be operated as peaking generators with an anticipated annual capacity factor of four to ten percent. The service life of the unit(s) is anticipated to be in excess of 35 years. Annual availability will be greater than 95 percent. Figure 4-11 below is an artist's rendering of what the Red River Valley plant will look like if both units are selected for construction.

**Figure 4-11**
**Red River Valley Artists Rendering**

## 4.4 Project Operation and Maintenance

The scope and frequency of maintenance work on the combustion turbine(s) will be in accordance with power industry standards and equipment manufacturer recommendations. Estimated service life of the units is in excess of 35 years, and is dependent upon the number and type of starts for peaking service.

The frequency of maintenance for major combustion turbine components is based on the number of unit start-ups and firing hours, and falls into three categories:

- Combustor inspections typically occur every 900 factored starts or 24,000 firing hours, and require a six-seven day outage;
- Hot gas path inspection and component replacement occurs about every 1,800 factored starts or 48,000 firing hours requiring a 11-13 day outage; and
- Major overhauls are scheduled about every 3,600 factored starts or 96,000 firing hours, and require a 23-25 day outage.

Based on the anticipated capacity factors and an average of six hours of operation per start, the units are anticipated to require major maintenance work every five to 10 years.

The operation and maintenance costs are based on Company experience with similar facilities, as well as industry and manufacturer information.

### 4.5 Project Cost Recovery

Our capital cost estimates for each combustion turbine unit are presented in Appendix C. We have taken care and worked closely with vendors to make our estimates as accurate as possible, and have included contingency estimates to reflect uncertainty at this stage in development. We have made considerable effort to try to make our Proposal comparable to those that may be received from independent power suppliers.

The cost recovery mechanism developed for the Metropolitan Emissions Reduction Project (Docket No. E002/M-02-633) is an example of a successful method of containing capital costs for new generation, and the Company proposes utilizing elements of that mechanism for this Project.[2]

We propose that a rate rider be established for each unit in our Proposal that is selected by the Commission. As in the MERP example, we propose each unit's ROE be adjusted up or down when placed in service to reflect any difference between the estimated capital cost presented in this filing compared to the actual capital cost of the units. The rider, with adjusted unit ROE, would be used during the first five years of rate recovery. Similar to MERP, this mechanism provides a real incentive to keep costs as low as possible and, in doing so, can deliver additional benefits to our customers.

The transmission and pipeline capital cost estimates we have presented in this filing for the Red River Valley Plant site are, by necessity, indicative. We have not yet identified a specific site, and routes for the transmission and gas support infrastructure have not been established or permitted. Similarly, we have not yet worked through the MISO generator interconnection process with the appropriate transmission owners to confirm what system upgrades may be necessary. We have based our estimates on assumptions about location and routes. We believe we have been conservative in preparing support infrastructure estimates for evaluation purposes, and it is very possible that actual project development estimates of the same quality as those we have presented for the combustion turbine power blocks

[2] The recovery mechanism was the product of a settlement agreement the Company entered into with the Department of Commerce, the Office of the Attorney General, the Minnesota Pollution Control Agency, the Minnesota Chamber of Commerce, Northstar Steel, the Suburban Rate Authority, the Izaak Walton League- Midwest Office, Minnesotans for an Energy-Efficient Economy, and the Sierra Club.

will be lower once a site and routes are established. Rather than use the indicative estimates presented here for cost recovery purposes, we propose to update transmission and gas pipeline estimates after a site and routes have been permitted and interconnection agreements achieved, and submit those updated support infrastructure estimates for Commission review to establish the baseline against which to compare actual cost.

Similar to the MERP approach, we propose the adjustments shown in Table 4-1 to the Company's last authorized ROE at the time the unit(s) are placed in service, which would be in a rider filing for Commission approval:

**Table 4-1**
**Proposed ROE Adjustments Based on Unit Costs**

| Actual Project Cost Compared to Estimate | Project ROE Adjustment Compared to Authorized ROE |
|---|---|
| Exceed estimate by more than 10% | 100 basis point reduction |
| Exceed estimate by up to 10% | 50 basis point reduction |
| At or below estimate by up to 5% | Authorized ROE |
| Below estimate by more than 5% but less than 10% | 50 basis point increase |
| Below estimate by 10% or more | 100 basis point increase |

## 4.6 Project Implementation Flexibility

Our proposal provides the Commission with considerable flexibility surrounding the number and timing of the combustion turbine units we offer. The various combinations of the number of units and their in service dates allow flexibility to combine part of our Proposal with others if that is most cost effective for our customers, or even to scale back the total amount of new generation added in the 2017 to 2019 timeframe if warranted.

*Size*

We provide flexibility around the number of units the Commission can choose to authorize. Each of the three units has been designed to be a separate project that can be implemented independently. The Commission could choose to select one, two, or three CT units for development in the 2017 to 2019 timeframe.

*Timing*

In combination with the choice of the number of units to select, we have designed our proposal to accommodate differing combinations of in service dates. Since

Black Dog Unit 6 is the most cost effective of the three combustion turbine proposals, we recommend it be developed first, before our Red River Valley units. Accordingly, we have provided cost estimates for Black Dog Unit 6 with in-service dates of 2017, 2018, or 2019, and for Red River Valley Unit 1 in 2018 or 2019. We have also provided estimates reflecting the joint construction of the two Red River Valley units as one project in either 2018 or 2019.

Our schedule to develop Black Dog Unit 6 by 2017 requires a significant amount of design engineering and arranging for gas supply modifications in 2014, and we anticipate making commitments to procure equipment in the third of fourth quarter of 2014. We also need to begin work to decommission Unit 4 in the Fall of 2014. There is not an opportunity to delay the in service date of the unit before making significant capital commitments.

However, there is adequate time to monitor resource needs during the next two years and adjust decisions to add more CT units in 2018 and/or 2019 if warranted. If the Commission wishes, the Company can provide an updated assessment of 2018 and 2019 resource needs in the Fall of 2014, and again in the Fall of 2015, for 2019 resource needs. The option to delay or even cancel a CT project in the 2018 and 2109 timeframe provides another opportunity to reduce ratepayer impacts if it can be done without compromising system reliability.

A decision to delay a 2018 unit to 2019 does not change our development estimates other than to shift the anticipated cost to the estimate associated with the new in service date.

We have noted in Appendix C the relatively small expenditure we anticipate making in 2014 and 2015 for a unit put into service in 2018 or 2019 unit. If the Commission chose to cancel a project at the end of 2014 or 2015, we would seek to recover those prudently incurred development expenditures represented in our estimates. In essence, the recovery of these minimal sunk costs is analogous to cancelation fees that might be included in a development contract with an independent power supplier.

# 5 Comparison of Company Proposal to Alternatives

As part of the process of developing our Proposal, the Company examined a broad range of alternatives to meet the resource need established by the Commission's Resource Plan Order. The rules and statutes governing Certificates of Need require that the applicant consider specific alternatives to aid the Commission's consideration of whether the Company's Proposal is in the public interest. The Company considered the following alternatives to fill the identified resource need: (i) peaking v. intermediate natural gas generation; (ii) increased renewable generation, including specific wind generation; (iii) increased demand side management to overcome the identified need; (iv) energy efficiency improvements at existing facilities; (v) purchased power; (vi) transmission lines in lieu of new generation; and (vii) distributed generation. In this chapter, we provide the Company's comparison of the Proposal with these other required alternatives. We believe that this analysis demonstrates that the staged deployment of three peaking units provided by our Proposal is the best alternative for meeting the needs of our customers.

## 5.1 Analytical Framework

The Resource Plan Order identified a need for new generation capacity on the Company's system of approximately 150 MW starting in 2017, growing to approximately 500 MW by 2019. The Order reflects the Commission's expectations over the "size" and "timing" of the resource to be procured, subject to development of a complete record in this proceeding.

However, the Resource Plan Order did not specify the "type" of resource the Commission desired to meet the identified need. The analysis conducted in that proceeding suggested both peaking and intermediate facilities may meet the identified need, and that the economic performance of these two generation profiles varied depending upon the assumptions used. The Commission referred the final determination of the best mix of resource type(s) to meet the identified need to this Docket.

To develop the Company's Proposal and to compare it with other types of resources, the Company analyzed a number of different perspectives to provide the Commission with a robust record upon which to make a decision. We reviewed and compared cost data for the alternatives considered. We considered the technical feasibility of alternatives. And we evaluated the risk associated with those alternatives.

One of the main analytical tools we used was the Strategist resource planning model. We have used Strategist in many previous planning dockets, and this modeling tool is also used by the Department of Commerce in its review of resource choices. In setting up Strategist for this proceeding, the Company used the base case from our December 18, 2012 resource plan filing as the starting point, modified only to take into account current circumstances. The assumptions we used in this base model reflect reasonable assumptions regarding future conditions that have already been scrutinized by the Commission and interested parties in our Resource Plan proceeding. We modified the December 2012 base case to simulate the study period 2013 through 2050. We also updated the model with our latest forecasts of coal, natural gas, and market energy prices. The assumptions we included in Strategist ensure a consistent review of comparable alternatives, and are consistent with the Commission's Resource Plan decision.

## 5.2 Peaking and Intermediate Natural Gas Resources

The Company examined the cost effectiveness of peaking and intermediate natural gas generation in developing our Proposal. To provide a robust comparison of the potential natural-gas alternatives, we replicated the comparative analysis presented in the Resource Planning proceeding, but with the cost and performance data updated to reflect our peaking proposal. We added the three peaking units to Strategist and compared the resulting peaking scenario to a scenario based on a large natural-gas, combined-cycle (intermediate) unit. Appendix C provides the Strategist inputs used for our peaking proposal.

The peaking resources were modeled as dispatchable units with heat rate curves that reflect the units' efficiency at various generation levels. Each unit's maximum capacity was modeled as approximately 230 MW in the winter, and 215 MW in the summer. The fuel costs are based on the forecasted costs of natural gas at the Ventura hub, with transportation cost adders included to reflect the expected cost at each of the sites. Because the units are expected to run infrequently, the impact of total system emissions is expected to be small. The Strategist modeling also included expected emission rates for $SO_2$, $NO_x$, $CO_2$, PM, CO, VOCs, and lead.

The costs associated with the Company's proposed peaking units are primarily capital expenditures. Black Dog Unit 6 is modeled to reflect (i) initial construction capital; (ii) forecasted on-going capital investments after the unit is in service; and (iii) a small capital investment for additional transmission infrastructure to connect the unit to the existing 115 kV system. The two Red River Valley units were modeled with the same three capital cost categories, plus an additional small capital investment necessary for construction of a natural gas pipeline to serve the units. The Strategist model also included forecasts for fixed and variable operating expenses. Our base case assumptions in Strategist were that Black Dog 6 would be in-service in Spring 2017, and the Red River Valley units would come on line in 2018 and 2019, respectively.

A scenario to reflect a large natural-gas, combined-cycle unit was also run through the Strategist model. Natural-gas, combined-cycle generators have higher capital expenditures for construction, but are more fuel efficient when generating. This intermediate alterative was modeled with an approximate maximum capacity of 800 MW for winter and 680 MW for summer. The average heat rate was 6.9 mmbtu/MWh, and the total construction cost was $620 million. The Company based its intermediate project estimate on a generic estimate of the cost of a new green field combined cycle power plant project.

Strategist simulated the total system cost over the 2013-2050 timeframe. The results are summarized as present value of revenue requirements (PVRR). Table 5-1 shows that our peaking alternative had a lower net system cost of $172 million compared to the generic intermediate unit using base case assumptions.

**Table 5-1**
**System Cost Comparison of Peaking and Intermediate Alternatives**

| | **Total PVRR 2013- 2050 ($ Millions)** | **Incremental Over Peaking Units** |
|---|---|---|
| **Peaking Units:**<br>**3 CTs @ 209 MW** | $88,922 | - |
| **Intermediate Unit:**<br>**1 CC @ 684 MW** | $89,094 | + $172 |

The addition of peaking resources fits well with the existing generation in our fleet. With relatively small capital investments to meet the need for additional power during peak demand periods, our system more fully utilizes existing intermediate plants at High Bridge and Riverside to meet energy requirements off peak. Thus the overall cost of energy from our system is lower.

Another benefit of our Proposal is its modular design, which allows modifying the scheduled in-service dates as conditions warrant. Based on the Commission's finding of need in our Resource Plan, we assume that the Red River Valley units will be placed in-service in early 2018 and 2019, respectively. Of course, if the Commission finds that the need for generation moderates, the Company can defer or combine its units to better match the evolving need. A delay in the in-service date of a CT under such circumstances saves customers a significant amount in fixed O&M and capital revenue requirements. For example, if the first Red River Valley unit were delayed until 2019, customers could realize a benefit on the order of approximately $20 million on a present value basis. If both units were further delayed until 2020, customers could save roughly an additional $50 million.

## 5.3 Purchased Power

We expect that this competitive acquisition process will attract proposals from independent power producers. We expect that other parties may submit offers for long- and short-term PPAs to fill all or some portion of the identified need.

While PPAs can be an appropriate choice under the circumstances, utility-owned generation can also provide long-term benefits to our customers that may not be available from PPAs. PPAs are typically 10 to 25 years long, and upon expiration the independent supplier owns the asset and is free to sell the facility's output to others or renegotiate terms for an extension. Utility-owned resources, on the other hand, will generally last 35 years or more, and the unit will remain available to ratepayers for even longer if the life of the unit is extended, as is often the case. This difference in length is an important difference that should be considered when comparing alternatives.

Short term purchase power agreements (less than 5 years) could also be part of a chosen portfolio, but only if they are shown to be a cost effective 'bridge' to extending the time period before investment in new generating capacity becomes necessary. We do not believe that a portfolio consisting of only short term purchased power is appropriate to fill the entire 500 MW of capacity in 2019. If shorter term capacity proposals are offered in the competitive acquisition process, they should be analyzed and compared to the proposals that rely on new generation to determine which reduce our customers' power supply costs over the long term.

## 5.4 Renewables

Renewable energy generation must be considered as alternatives to proposed generation projects. The Company has had great success adding cost effective renewable energy resources to our system, and will continue to pursue additional cost effective renewable energy opportunities as they arise. However, based on Strategist simulations, renewable generation alternatives do not appear to be suitable to meet the capacity need identified by the Commission. We chose to model two types of renewable alternatives using Strategist.

First, we considered a biomass resource because it is generally dispatchable and can provide significant capacity that can be depended on to meet our customers' energy needs. The biomass alternative was modeled as five individual projects with a total capacity of 500 MW in the winter, and 485 MW in the summer. The average heat rate of these units was 12.9 mmbtu/MWh, and the average fuel cost in the 2017-2019 timeframe was $3.00/mmbtu. Based on the Company's experience with similar units, the biomass alternative was modeled as 'must run,' meaning that the units must operate at least at their minimum capacity levels unless off line for maintenance. Typically a developer supports this assumption to be assured of enough revenue to meet financing obligations and operating costs. The total capital costs of these units were $1.8 billion.

Second, we included an evaluation of solar resources as an alternative. The solar alterative was modeled as 22 separate 50 MW projects with in-service dates between 2017 and 2019. Because solar is a variable generation resource, it is not 100 percent reliable during our peak system demand. As such, we modeled solar as having an accredited capacity of 42 percent of its maximum capacity rating.[1] With this assumption the total summer capacity of the solar projects totals 462 MW. Given the rapid changes in the cost of solar, and the fact that the federal investment tax credit for solar is set to expire in 2016, the future cost of these resources is very uncertain. For this analysis the Company assumed a price of $125/MWh, which reflects our expectation of current market prices.

[1] The 40 percent accredited capacity assumption is only an approximate value. In the next few months, Company will be filling a study that calculates the effective load carrying capability (ELCC) of solar generation. This study will set the level of accredited capacity that the company uses in the future. The Company is willing to supplement the record in this proceeding with that study when it is completed and has been submitted.

The results of the Strategist simulations are presented in Table 5 – 2. The PVRR results for both the renewable energy alternatives are significantly higher that the results for the natural gas alternatives.

**Table 5-2**
**System Cost Comparison of Renewable Alternatives**

| | **Total PVRR 2013- 2050 ($ Millions)** | **Incremental Over Peaking Units** |
|---|---|---|
| **Peaking Units:<br>3 CTs @ 209 MW** | $88,922 | - |
| **Biomass Alternative:<br>5 units @ 100 MW** | $90,515 | +$1,592 |
| **Solar Alternative:<br>22 units @ 50 MW** | $89,400 | +$478 |

The biomass alternative is the most expensive of the resources modeled. This is due to very high capital costs and relatively expensive fuel. The biomass alternative was modeled as emitting zero CO2, which created a benefit for this alternative of $380 million in comparison to the natural gas alternatives. Even with this emissions benefit, the biomass alternative was not cost effective. In addition, we have concerns over whether sufficient fuel would be available to serve such a large biomass project, and we are concerned that this alternative may not be feasible.

The solar alternative was also more expensive than the natural gas options. The 1,100 MW of installed solar capacity created large fuel cost savings, but they were not sufficient to offset the high cost that was assumed in Strategist. Note that the Strategist model did not include a cost for solar integration. Currently, the NSP system has about 10 MW of solar generation. At this level the intermittent generation from solar resources can be easily integrated into our system without significant changes to how our generation fleet is dispatched. However, if the amount of solar in the NSP system was to increase to 1,100 MW as contemplated in this alternative, we would need to change the way our system is operated in order to maintain reliable service for our customers. For example, the amount of spinning reserves that are maintained during the day would need to be increased. Spinning reserves are additional generation capacity that can quickly be called upon in the event that other resources (such as solar) suddenly decrease their amount of generation.

The Company considered wind energy including Community-Based Energy Development ("C-BED") as an alternative. Minnesota Statutes Section 216B.1612, subdivision 5 requires the Company to "take reasonable steps to determine if one or more C-BED projects are available that meet the utility's cost and reliability requirements . . . ." Because wind is a variable generation resource, it is not suitable to fulfill the dispatchable generation capacity need identified by the Commission.

We note that the Company recently issued an RFP for all types of additional wind resources including the potential for C-BED proposals. These projects will be evaluated for cost effectiveness, and if successful will be submitted for regulatory approval. In order to integrate additional cost effective renewable resources such as wind power into a utility system, there must also be adequate dispatchable resources to complement them so that demand can be met reliably. While wind power cannot meet peaking or intermediate duty in our system, the addition of peaking generation allows us to continue to take advantage of the low energy production costs of wind power.

Minnesota Statutes Section 216B.243, subdivision 3(10) states that the Commission shall evaluate whether the applicant is in compliance with the applicable provisions of Minnesota Statutes Sections 216B.1691 (the RES statute), and 216B.2425, subdivision 7. The RES requires the Company to obtain renewable generation resources sufficient to produce 30 percent of retail electric sales by eligible renewable energy resources by 2020. The Department issued a letter on July 8, 2010, in Docket No. E999-PR-10-267, verifying that the Company was in compliance with the RES for 2009. Since then we have made annual compliance reports to the Commission demonstrating that we continue to comply with the requirements of the Statute. As we have reported in our Resource Plan dockets, the Company is well positioned to comply with Minnesota's RES - as well as the renewable policies of the other states we serve - well into the future. With the renewable based generation on our system and the renewable energy credits we have banked, we can continue to comply until 2018 or 2019. Additions that may come out of the current Wind RFP competitive bidding process will extend our compliance capability further.

## 5.5 Demand Side Management

Demand-Side Management (DSM) is another category of potential alternatives to new generation. Our existing DSM programs are presented in detail in Appendix B.

As discussed in our recent Resource Plan, we are committed to achieving or exceeding our DSM goals. The Commission recently approved the Company's 2013-2015 Conservation Improvement Program (CIP), which sets goals to reach 1.5 percent savings. The Company proposes to attain these goals by launching new programs and expanding our existing programs. However, these aggressive goals suggest that additional gains may be difficult to achieve and sustain.

Minnesota currently has the second largest nationally reported potential peak reduction, as noted by FERC in their assessment study for 2012. This reduction is made up of traditional demand response programs such as direct load control (Saver's Switch) and Interruptible Rates. The Company's 2013-2015 overall electric CIP filing included incremental additions to our demand response portfolio. The projected incremental growth to our programs includes the anticipated impact of new EPA rules affecting our C&I customers, and the most recent load research which shows a decrease in available load relief (a decline in kW relief potential on a per switch basis). Given the considerable existing portfolio, combined with limited potential for traditional demand response, we project small, deliberate growth for the next three years.

We undertook a benchmarking study that projected the potential of 304 MW of additional load reduction. However, it is not clear that this potential can be realized in a cost-effective manner, and the potential has not yet been adequately defined for the Company to make definitive judgments about its potential. We will be commissioning further work to help refine this analysis and incorporate the results in our next Resource Plan filing, as directed by the Commission. However, at this time, we do not believe that conservation measures can be relied on to reduce the current identified need.

We believe that it is important to determine whether additional demand response can be achieved and sustained before treating DSM as a generation alternative that can be depended upon to maintain reliable service to our customers. Our conservation initiatives are being actively debated in Docket E-999/CI-09-1449.

Finally, we also considered increasing efficiency at existing facilities as an alternative. The type of efficiency project that would be appropriate to fill the identified 500 MW capacity need must increase the maximum output from a facility without substantially increasing the fuel inputs. The Company has completed such a project at the Monticello nuclear facility that added 77 MW of capacity in 2013. Also, when Sherburne County Unit 3 returns to service this year, it will have an additional 10 MW of generation capacity. The Company will continue to pursue projects like these to the extent that they are identified as cost effective for our customers. However, at this time the Company has not identified any additional cost effective efficiency opportunities within our generation fleet.

### 5.6 Other Alternatives

New transmission is not a viable alternative for our Proposal. The underlying assumption with this alternative is that additional transmission infrastructure would provide access to new or existing capacity resources. We are currently unaware of additional generation resources that, with the construction of new transmission, could cost effectively provide our customers with the needed energy and capacity. Timing is also an issue when considering transmission as a viable alternative. Transmission capacity of any size can take several years to plan, permit, site, and construct, and would likely not be available in time to meet the customer need.

Pursuant to Minnesota Statutes Section 216B.2426, we also considered the use of distributed generation to meet the established need. In Minnesota, distributed generation ("DG") is defined generally as generation that is located on or near the site where the output is primarily to be used, interconnected to and operated in parallel with the electric grid, and has a total capacity of no more than 10 MW.[2] Additionally, the capacity of the DG installation must be lower than the minimum load of the distribution system to which it would be interconnected so that the energy generated by the DG facility is used locally.[3]

We identified the cost of solar in our discussion of renewable resources above, and believe that distributed solar generation would be at or above those cost

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[2] In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212, Docket No. E-999/CI-01-1023, ORDER ESTABLISHING STANDARDS (September 28, 2004). Minnesota defines renewable projects between 10 and 40 megawatts as "dispersed" renewable generation (DRG). See Laws of Minnesota 2007, chapter 136, article 4, section 17.

[3] See "Potential for and Barriers to State Jurisdiction Over Interconnecting Dispersed Generation Projects," Minnesota Office of Energy Security, June 6, 2008; and Phase II Report of the Technical Standards Workgroup Regarding Distributed Generation, MPUC Docket No. E999/CI-01-1023, Attachment 1, page 1.

levels. Thermal distributed generation such as micro turbines and reciprocating engines is also cost prohibitive. The U.S. Energy Information Administration estimated the cost of DG resources to be two to two-and-a-half times more expensive to construct than conventional peaking resources such as those proposed by the Company.

Minnesota Statutes § 216B.1694 requires consideration of an innovative energy alternative as a supply option. At this time, the Company is not aware of an innovative energy project available to meet the need.

## 5.7 Conclusion

The Proposal represents the best alternative available to our customers by adding low capital cost generation to the system, which fits well with the existing Xcel Energy generation fleet and can be added incrementally as needed within relatively short time frames. The Company looks forward to working with the Department and other stakeholders to assist the Commission in determining the best generation option to meet our customers' needs.

# 6 Environmental Information

This section discusses the environmental impacts of our Proposal.

## 6.1 Air Impacts

### 6.1.1 Generation Air Emissions

Natural gas-fired combustion turbine technology is among the cleanest means of generating utility-scale electricity. Natural gas combustion generates significantly less carbon dioxide, particulate matter, sulfur dioxide, and hazardous air pollutant emissions (including mercury) than oil or coal.

The primary constituents of concern resulting from combustion of natural gas are oxides of nitrogen ($NO_x$), carbon monoxide (CO), and volatile organic compounds (VOCs). Our Proposal will control $NO_x$ emissions through use of dry low-$NO_x$ burners. Good combustion practices will be used to control emissions of fine particulates, CO, and VOCs.

*Black Dog Site*

There will be a single combustion turbine at the Black Dog site. An air emissions permit application will be submitted in mid-2014. Because our Proposal will serve peaking duty in Xcel Energy's system, and thus operate a limited number of hours per year, we have elected to pursue an air quality permit that will limit, or cap, the total number of hours the CT will be allowed to operate. Emissions categories regulated by the federal Prevention of Significant Deterioration ("PSD") program will be netted against the current emissions from the coal-fired units so that the project will not be subject to PSD for any emissions, with the possible exception of CO. Taking this approach streamlines the air permitting process.

Table 6-1 presents the estimated air emissions from Black Dog Unit 6. Estimated impacts to ambient air quality summarized in Table 6-2 are based on preliminary modeling using an EPA approved dispersion model (AERMOD).

**Table 6-1**
**Estimated Project Air Emissions for Black Dog 6**

| EPA Criteria Pollutants | | |
|---|---|---|
| Pollutant | Emission Rate at Rated Capacity (average ambient conditions, base load) (lbs/hour) | Emissions at Projected Annual Operating Hours (tons/year) |
| SO2 | 3 | 1 |
| NOx | 77 | 43 |
| PM10 | 23 | 9 |
| PM2.5 | 23 | 9 |
| CO | 47 | 83 |
| VOC | 6 | 9 |
| EPA Hazardous Air Pollutants | | |
| 1,3-Butadiene | 0.00 | 0.00 |
| 1,4 Dichlorobenzene | 0.00 | 0.00 |
| Acetaldehyde | 0.09 | 0.04 |
| Acrolein | 0.01 | 0.01 |
| Arsenic | 0.00 | 0.00 |
| Benzene | 0.03 | 0.01 |
| Beryllium | 0.00 | 0.00 |
| Cadmium | 0.00 | 0.00 |
| Chromium | 0.00 | 0.00 |
| Cobalt | 0.00 | 0.00 |
| Ethylbenzene | 0.07 | 0.03 |
| Formaldehyde | 1.65 | 0.65 |
| Lead | 0.00 | 0.00 |
| Manganese | 0.00 | 0.00 |
| Mercury | 0.00 | 0.00 |
| Naphthalene | 0.00 | 0.00 |
| Nickel | 0.00 | 0.00 |
| Polycyclic Aromatic | 0.01 | 0.00 |
| Propylene Oxide | 0.07 | 0.03 |
| Selenium | 0.00 | 0.00 |
| Toluene | 0.30 | 0.12 |
| Xylenes | 0.15 | 0.06 |

Note: Annual emissions at 9% capacity factor, with startup and shutdown periods.

**Table 6-2**
**Estimated Maximum Contributions to Ambient Air Quality for Black Dog 6**

| Pollutant | Ground-level Concentrations (µg/m$^3$) | National and Minnesota Ambient Standards (µg/m$^3$) |
|---|---|---|
| $O_2$ (24-hour) | 0.02 | 365 |
| $NO_2$ (24-hour) | 0.51 | -- |
| $PM_{10}$ (24-hour) | 0.15 | 150 |

Note: Based on stack height of 230 feet and combustion turbines at 100% load. Dispersion model used emission rates at winter ambient temperatures to account for worst case.

*Red River Valley Site*

The Red River Valley site will be able to support two CTs, which are capable of rapid starts to support the rapid changes in wind generation. An air emissions permit application will be submitted in late 2014 to early 2015. Because these are peaking units that will operate a limited number of hours per year, we have elected to pursue an air quality permit that will cap the total number of hours the CTs will be allowed to operate. PSD requirements are expected to apply to one or more emissions categories, depending on whether one or two combustion turbines will be sited. Under PSD, limits will be set based on a Best Available Control Technology analysis.

Table 6-3 presents the estimated air emissions from the new CTs at the Red River Valley site. Estimated impacts to ambient air quality summarized in Table 6-4 are based on preliminary modeling using an EPA approved dispersion model (AERMOD).

## Table 6-3
## Estimated Project Air Emissions for Red River Valley CTs

| EPA Criteria Pollutants | | | | |
|---|---|---|---|---|
| Pollutant | Emission Rate at Rated Capacity (average ambient conditions, base load) (lbs/hour) | | Emissions at Projected Annual Operating Hours (tons/year) | |
| | 1 Unit at Red River Valley | 2 Units at Red River Valley | 1 Unit at Red River Valley | 2 Units at Red River Valley |
| SO2 | 3 | 6 | 1 | 2 |
| NOx | 77 | 154 | 43 | 86 |
| PM10 | 23 | 46 | 9 | 18 |
| PM2.5 | 23 | 46 | 9 | 18 |
| CO | 47 | 94 | 83 | 166 |
| VOC | 6 | 12 | 9 | 18 |
| EPA Hazardous Air Pollutants (HAPs) | | | | |
| 1,3-Butadiene | 0.00 | 0.00 | 0.00 | 0.00 |
| 1,4 | 0.00 | 0.01 | 0.00 | 0.00 |
| Acetaldehyde | 0.09 | 0.19 | 0.04 | 0.07 |
| Acrolein | 0.01 | 0.03 | 0.01 | 0.01 |
| Arsenic | 0.00 | 0.00 | 0.00 | 0.00 |
| Benzene | 0.03 | 0.06 | 0.01 | 0.02 |
| Beryllium | 0.00 | 0.00 | 0.00 | 0.00 |
| Cadmium | 0.00 | 0.01 | 0.00 | 0.00 |
| Chromium | 0.00 | 0.01 | 0.00 | 0.00 |
| Cobalt | 0.00 | 0.00 | 0.00 | 0.00 |
| Ethylbenzene | 0.07 | 0.15 | 0.03 | 0.06 |
| Formaldehyde | 1.65 | 3.31 | 0.65 | 1.30 |
| Lead | 0.00 | 0.00 | 0.00 | 0.00 |
| Manganese | 0.00 | 0.00 | 0.00 | 0.00 |
| Mercury | 0.00 | 0.00 | 0.00 | 0.00 |
| Naphthalene | 0.00 | 0.01 | 0.00 | 0.00 |
| Nickel | 0.00 | 0.00 | 0.00 | 0.00 |
| Polycyclic | 0.01 | 0.01 | 0.00 | 0.00 |
| Propylene Oxide | 0.07 | 0.14 | 0.03 | 0.05 |
| Selenium | 0.00 | 0.00 | 0.00 | 0.00 |
| Toluene | 0.30 | 0.61 | 0.12 | 0.24 |
| Xylenes | 0.15 | 0.30 | 0.06 | 0.12 |

Note: Annual emissions at 9% capacity factor, with startup and shutdown periods.

**Table 6-4**
**Estimated Maximum Contributions to Ambient Air Quality for the Red River Valley site**

| Pollutant | Ground-level Concentrations ($\mu g/m^3$) | | National and North Dakota Ambient Standards ($\mu g/m^3$) |
|---|---|---|---|
| | 1 Unit at North Dakota | 2 Units at North Dakota | |
| $SO_2$ (24-hour) | 0.05 | 0.09 | 365 |
| $NO_2$ (24-hour) | 1.18 | 2.25 | -- |
| $PM_{10}$ (24-hour) | 0.37 | 0.70 | 150 |

Note: Based on stack height of 65 feet and combustion turbines on natural gas as primary fuel, at 100% load. Dispersion model used emission rates at winter ambient temperatures for worst case.

### 6.1.2 Transmission Air Emissions

The potential air emissions associated with our Proposal's transmission lines are negligible. However, there is potential for ozone and nitrogen oxide due to corona. Corona consists of the breakdown or ionization of air within a few centimeters of conductors which can produce ozone and oxides of nitrogen in the air surrounding the conductor. Typically some imperfection such as a scratch on the conductor or a water droplet is necessary to cause corona. Ozone is not only produced by corona, but also forms naturally in the lower atmosphere from lightning discharges and from reactions between solar ultraviolet radiation and air pollutants, such as hydrocarbons from auto emissions. The natural production rate of ozone is directly proportional to temperature and sunlight, and inversely proportional to humidity. Thus humidity or moisture, the same factors that increase corona discharges from transmission lines, inhibits the production of ozone. Ozone is a very reactive form of oxygen molecules and combines readily with other elements and compounds in the atmosphere. Because of its reactivity, it is relatively short lived. For a 230 kV transmission line, the conductor gradient surface is usually below the air breakdown level.

Currently, both state and federal governments have regulations regarding permissible concentrations of ozone and $NO_2$. The applicable standards for these compounds in parts per million ("ppm") are presented in Table 6-5.

**Table 6-5**
**Applicable Ambient Air Quality Standards for Transmission Projects**

| Pollutant | Level | Averaging Time | National or Minnesota/North Dakota Standard |
|---|---|---|---|
| Nitrogen Dioxide | 0.100 ppm | 1-hour | National |
| Nitrogen Dioxide | 0.053 ppm | Annual | National |
| Nitrogen Dioxide | 0.053 ppm | Annual | North Dakota |
| Nitrogen Dioxide | 0.050 ppm | Annual | Minnesota |
| Ozone | 0.075 ppm | 8-hour | National |
| Ozone | 0.075 ppm | 8-hour | North Dakota |
| Ozone | 0.08 ppm | 8-hour | Minnesota |

For the overhead design on the existing 115kV line to Black Dog Substation, the predicted ozone concentration is 0.00005 ppm for foul weather (worst case) conditions. The corona loss estimate is 0.02 W/m.

For the overhead design on the proposed route to interconnect the two Red River Valley CTs to the area transmission system, the predicted ozone concentration for 230 kV/230 kV double circuit design with both circuits in service is 0.0007 ppm for foul weather (worst case) conditions. The corona loss estimate is 0.4 W/m. These calculations are obtained from the Software Applications for the EPRI AC Transmission Line Reference Book, 200kV and Above, Third Edition.

These results are well below both federal and state standards. Most calculations of the production and concentration of ozone assume high humidity or rain, with no reduction in the amount of ozone due to oxidation or air movement.

### 6.1.3 Fugitive Dust

Site preparation and construction activities to include construction of the transmission lines will produce small amounts of fugitive dust from earth-moving, construction, and right-of-way clearing on the Red River Valley site. Fugitive emissions from earth-moving and construction will be controlled on both sites by watering or applying dust suppressants to exposed soil surfaces as necessary. Adverse impacts to the surrounding environment will be minimal because of the short and intermittent nature of the overall emissions and dust-producing earth-moving, construction, and right-of way clearing processes.

Fugitive dust emissions will not be generated in any significant amounts during operation of the plants at either site, and will be reduced with the elimination of coal as a fuel at the Black Dog site. Adverse impacts to the surrounding environment will be minimal because of the short and intermittent nature of the emission and dust-producing construction phases.

## 6.2 Noise Impacts

### 6.2.1 Generation Noise

Noise from the generating units is not expected to have a significant impact. The generating units will be in compliance with state and local noise standards. The generation at either site is located in an isolated area with the nearest residences located more than 1,500 feet away from the plant. Noise from the operation of the new generating units is expected to be predominantly low frequency noise, as is noise from traffic. Noise from the generation operations will not significantly impact the acoustical environment given the noise control technology that will be employed by the new generating units. In addition, noise at the Black Dog site will be reduced by the retirement of existing Units 3 and 4 and elimination of the noise associated with coal trains and other coal and ash handling processes.

To control potential generation noise impacts and meet applicable standards, the Company will potentially employ several noise mitigation measures including:

1. Installing the Black Dog combustion turbine inside of the existing generation building;
2. Combustion turbine generator air inlet silencer; and
3. Diesel engine silencers.

Thus, generation operation is expected to be 50 dBA at the nearest residence, which meets the state noise standards established by the Minnesota Pollution Control Agency (MPCA) and the North Dakota Department of Health (NDDOH).

Temporary noise will also be generated by the construction of the Project. Construction noise will be predominantly from intermittent sources originating from diesel engine driven construction equipment. Potential noise impacts will be mitigated by proper muffling equipment fitted to construction equipment, as well as by restricting activities if necessary. Additional noise will be generated by pile driving activities. Pile driving activities at the Red River Valley site are expected to last three months and to occur in 2016 through 2017. No pile driving activity is expected for the Black Dog site.

### 6.2.2 Demolition Noise

At the Black Dog site, existing Units 3 and 4 will be retired along with other coal and ash handling processes. Site demolition activities will generate noise. Potential noise impacts will be mitigated by proper muffling equipment fitted to construction equipment, as well as restricting activities if necessary. This activity is expected to occur beginning in 2014 and ending in 2019.

### 6.2.3 Transmission Noise

Overhead transmission conductors produce noise under certain conditions. The level of noise depends on conductor conditions, voltage level, and weather conditions. Generally, activity-related noise levels during the operation and maintenance of substations and transmission lines are minimal.

Noise emission from a transmission line occurs during certain weather conditions. In foggy, damp, or rainy weather, power lines can create a crackling sound due to the small amount of electricity ionizing the moist air near the wires. During heavy rain the background noise level of the rain is usually greater than the noise from the transmission line. As a result, people do not normally hear noise from a transmission line during heavy rain. During light rain, dense fog, snow, and other times when there is moisture in the air, transmission lines can produce noise.

However, noise levels produced by a 230 kV transmission line are generally less than outdoor background levels and are therefore not typically audible. The noise generated from the transmission lines is not expected to exceed the background noise levels and would therefore not be audible at any receptor location.

## 6.3 Water Needs

The advantage of simple cycle technology is that it can operate without using significant quantities of water. It is estimated that over 80 percent of the time the Project CTs operate, no water will be used. Up to 20 percent of the time it is anticipated that evaporative cooling will be used to cool the inlet air of the CTs. This enhances operational efficiency of the units during the warmest days of the year. Evaporative cooling increases the humidity, which results in the cooling of the air entering the combustion turbine. The evaporative cooling process consumes a small amount of water, but increases output by about 5 to 10 percent, depending on the relative humidity during hot summer day operation. Details of expected water usage are provided in Tables 4a and 4b in Appendix C for the Black Dog site and the Red River Valley site, respectively.

At the Black Dog site groundwater from an existing site well will supply evaporative cooling water and other water needs for Unit 6. No increase in the groundwater appropriation rate or annual withdrawal volume will be required at the Black Dog site. The annual withdrawal volumes for future site operations (new and existing units) are expected to be within the range of existing plant operations.

The Red River Valley site would require new groundwater wells to provide for site water needs. Groundwater appropriations permitting would be required. Lacking groundwater sufficient to supply plant needs, water would be trucked in and stored on-site.

## 6.4 Waste Generation

*Black Dog Site*

Wastewater generation associated with operation of Unit 6 will be reduced from that of the existing plant with the cessation of once-through cooling for existing units 3 and 4. The solid waste generation will be reduced because there will no longer be coal ash generated at the plant.

Estimates of discharges to water and solid wastes attributable to operation of Unit 6 are provided in Table 6-6. All waste management activities will be conducted in accordance with applicable rules, regulations, and permits.

Sanitary wastewater will continue to be discharged to the existing sanitary sewer system. Other liquid wastes will stem from routine maintenance activities. No radioactive releases will occur as a result of the Project.

**Table 6-6**
**Black Dog Site Liquid and Solid Wastes**

| Waste | Phase | Description | Generation Rate | Disposition Method |
|---|---|---|---|---|
| 7849.0320F | Potential Sources and types of discharges to water attributable to operation of the facility | | | |
| RO Reject Water | Liquid | Water containing dissolved solids present in the raw water source except at a greater concentration. | <0.4 MGPY<br>15 gpm (max.) | Discharge to surface waters under NPDES permit or discharge to sanitary sewer |
| Service Water | Liquid | Equipment wash water | <1 MGPY similar to present except during construction | Discharge to surface waters under NPDES permit or discharge to sanitary sewer |
| 7849.0320G.2 Radioactive Releases | | None – natural gas combustion | | |
| 7849.0320H | Potential types and quantities of solid wastes in tons per year at expected capacity factor | | | |
| Maintenance Materials | Solid | Lubricants, hydraulic fluid, etc. | <10 barrels/yr | Manage used oil with a contract firm |
| Maintenance Materials | Solid | Oily and greasy rags, materials packaging, office waste, domestic-type solid wastes, cleaning solvents. | <5 tons/yr | Dispose of properly as specially regulated, solid or hazardous waste and/or recycle as feasible and allowable |
| Settling Pond Accumulation | Solid | Maintenance cleaning of settled solids | ~0 tons/year | Dispose of properly as specially regulated or solid waste or with dredge spoils |

*Red River Valley Site*

Table 6-7 summarizes the information on the solid and liquid wastes generated by the CTs at the Red River Valley site. The most significant waste streams from the Project will be wastewater resulting from the treatment process for groundwater used for evaporative cooling. The wastewater will be similar in makeup to the groundwater and will be a relatively small volume. Other solid and liquid wastes will stem from routine maintenance activities. There will be no radioactive releases.

All waste management activities will be conducted in accordance with applicable rules and regulations. Site domestic wastewater will be discharged to an on-site drain field.

**Table 6-7**
**Red River Valley Site Liquid and Solid Wastes**

| Waste | Phase | Description | Generation Rate | Disposition Method |
|---|---|---|---|---|
| 7849.0320F | Potential Sources and types of discharges to water attributable to operation of the facility | | | |
| RO Reject Water | Liquid | Water containing dissolved solids present in the raw water source except at a greater concentration. | <0.8 MGPY<br>30 gpm (max.) | Discharge to surface waters under NPDES permit or discharge to sanitary sewer |
| Service Water | Liquid | Equipment wash water | 2 MGPY similar to present except during construction | Discharge to surface waters under NPDES permit or discharge to sanitary sewer |
| 7849.0320G.2 Radioactive Releases | | None – natural gas combustion | | |
| 7849.0320H | Potential types and quantities of solid wastes in tons per year at expected capacity factor | | | |
| Maintenance Materials | Solid | Lubricants, hydraulic fluid, etc. | <20 barrels/yr | Manage used oil with a contract firm |
| Maintenance Materials | Solid | Oily and greasy rags, materials packaging, office waste, domestic-type solid wastes, cleaning solvents. | <10 tons/yr | Dispose of properly as specially regulated, solid or hazardous waste and/or recycle as feasible and allowable |
| Settling Pond Accumulation | Solid | Maintenance cleaning of settled solids | 5 tons/year | Dispose of properly as specially regulated or solid waste or with dredge spoils |

## 6.5 Electric and Magnetic Fields

No adverse impacts from electric and magnetic fields associated with the CTs' transmission lines are expected.

The term electromagnetic field ("EMF") refers to electric and magnetic fields that are coupled together such as in high frequency radiating fields. For the lower frequencies associated with power lines (referred to as "extremely low frequencies" ("ELF")), EMF should be separated into electric fields ("EFs") and magnetic fields ("MFs"), measured in kilovolts per meter ("kV/m") and milligauss ("mG"), respectively. These fields are dependent on the voltage of a transmission line (EFs) and current carried by a transmission line (MFs). The intensity of the EF is proportional to the voltage of the line, and the intensity of the MF is proportional to the current flow through the conductors. Transmission lines operate at a power frequency of 60 hertz (cycles per second).

### 6.5.1 Electric Fields

There is no federal standard for transmission line electric fields. The Commission, however, has imposed a maximum electric field limit of 8 kV/meter measured at one meter above the ground. *In the Matter of the Route Permit Application for a 345 kV Transmission Line from Brookings County, South Dakota to Hampton, Minnesota,* Docket No. ET-2/TL-08-1474, Order Granting Route Permit (*adopting* ALJ Findings of Fact, Conclusions and Recommendation at Finding 194 (April 22, 2010 and amended April 30, 2010)) (September 14, 2010).

*Black Dog Site*

The maximum electric field, measured at one meter above ground, associated with the existing 115kV line to Black Dog Substation is calculated to be 1.18 kV/m. The calculated EFs for the Project are provided in Table 6-8.

**Table 6-8**
**Calculated Electric Fields (KV/M) For 115 KV Transmission Line Designs (One meter above ground) for the Black Dog Project**

| Structure Type | Maximum Operating Voltage (kV) | Distance to Proposed Centerline | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | -300' | -200' | -100' | -50' | -25 | 0' | 25 | 50' | 100' | 200' | 300' |
| 115Kv Steel Circuit Black Dog Plant to Black Dog Substation | 121 | 0.00 | 0.00 | 0.03 | 0.14 | 0.46 | 1.18 | 1.10 | 0.79 | 0.11 | 0.02 | 0.00 |

*Red River Valley Site*

The maximum electric field, measured at one meter above ground, associated with the Red River Valley Project is calculated to be 2.04 kV/m. The calculated electric fields for the Project are provided in Table 6-9.

**Table 6-9**
**Calculated Electric Fields (KV/M) For Proposed 230 KV Transmission Line Designs (One meter above ground) for the Red River Valley Facility**

| Structure Type | Maximum Operating Voltage (kV) | Distance to Proposed Centerline | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | -300' | -200' | -100' | -50' | -25 | 0' | 25 | 50' | 100' | 200' | 300' |
| 230Kv Steel Pole Double Circuit I-String | 242 | 0.00 | 0.02 | 0.06 | 0.62 | 2.04 | 1.18 | 2.04 | 0.62 | 0.08 | 0.02 | 0.00 |

### 6.5.2 Magnetic Fields

There are presently no Minnesota or North Dakota regulations pertaining to MF exposure.

*Black Dog Site*

Magnetic fields are calculated for the existing 115kV line to Black Dog Substation two system conditions: the expected peak and average current flows for the year 2013. The peak MF values are calculated at a point directly under the transmission line and where the conductor is closest to the ground. The same method is used to calculate the MF at the edge of the right-of-way. The calculated MFs show that fields decrease rapidly as the distance from the centerline increases (proportional to the inverse square of the distance from source).

The MF produced by a transmission line is dependent on the current flowing on its conductors. Therefore, the actual MFs when the Project is placed in service are typically less than shown in Table 6-10. Actual current flow on the line will vary with system conditions, so MFs would be less than peak levels during most hours of the year.

**Table 6-10**
**Calculated Magnetic Flux density (milligauss) for 115 kV**
**Transmission Line Design for the Black Dog Project (One meter above ground)**

| Segment | System Condition | Current (Amps) | Distance to Proposed Centerline | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | -300’ | -200’ | -100’ | -50’ | -25 | 0’ | 25 | 50’ | 100’ | 200’ | 300’ |
| 115kV Single Circuit to Black Dog Substation | Peak | 1255 | 1.36 | 2.93 | 10.07 | 29.62 | 67.65 | 190.22 | 234.62 | 90.99 | 19.42 | 4.31 | 1.88 |
| | Average | 753 | 0.82 | 1.76 | 6.04 | 17.77 | 40.59 | 114.13 | 140.77 | 54.59 | 11.65 | 2.59 | 1.13 |

*Red River Valley Site*

Magnetic fields are calculated for the transmission at the Red River Valley site under two system conditions: the expected peak and average current flows as projected for the year 2018. The calculated magnetic fields for the units are provided in Table 6-11.

**Table 6-11**
**Calculated Magnetic Flux density (milligauss) for Proposed 230 kV**
**Transmission Line Design (One meter above ground) for the Red River Valley Facility**

| Segment | System Condition | Current (Amps) | Distance to Proposed Centerline | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | -300’ | -200’ | -100’ | -50’ | -25 | 0’ | 25 | 50’ | 100’ | 200’ | 300’ |
| 230kV Steel Pole Double Circuit I-String | Peak | 600/600 | 0.48 | 1.27 | 7.51 | 30.89 | 67.75 | 92.48 | 66.08 | 29.55 | 6.91 | 1.09 | 0.41 |
| | Average | 360/360 | 0.29 | 0.76 | 4.51 | 18.53 | 40.65 | 55.49 | 39.65 | 17.73 | 4.15 | 0.6 | 0.25 |

Considerable research has been conducted throughout the past three decades to determine whether exposure to power-frequency (60 hertz) MFs causes biological responses and health effects. Epidemiological and toxicological studies have shown no statistically significant association or weak associations between MF exposure and health risks. The possible impact of exposure to EMFs upon human health has also been investigated by public health professionals for the past several decades. While the general consensus is that EFs pose no risk to humans, the question of whether exposure to MFs can cause biological responses or health effects continues to be debated.

In 1999, the National Institute of Environmental Health Sciences (“NIEHS”) issued its final report on “Health Effects from Exposure to Power-Line Frequency Electric and Magnetic Fields” in response to the Energy Policy Act of 1992. The NIEHS concluded that the scientific evidence linking MF exposure with health risks is weak, and that this finding does not warrant aggressive regulatory concern. However, because of the weak scientific evidence that supports some association between MFs and health effects, passive regulatory action, such as providing public education on reducing exposures, is warranted.

In 2007, the World Health Organization ("WHO") concluded a review of the health implications of electromagnetic fields. In this report, WHO stated:

> Uncertainties in the hazard assessment [of epidemiological studies] include the role that control selection bias and exposure misclassification might have on the observed relationship between magnetic fields and childhood leukemia. In addition, virtually all of the laboratory evidence and the mechanistic evidence fail to support a relationship between low-level [extremely low frequency] magnetic fields and changes in biological function or disease status. Thus, on balance, the evidence is not strong enough to be considered causal, but sufficiently strong to remain a concern. (WHO, 2007 at p. 12).

Also, regarding disease outcomes, aside from childhood leukemia, WHO stated:

> A number of other diseases have been investigated for possible association with ELF magnetic field exposure. These include cancers in children and adults, depression suicide, reproductive dysfunction, developmental disorders, immunological modifications, and neurological disease. The scientific evidence supporting a linkage between ELF magnetic fields and any of these diseases is much weaker than for childhood leukemia and in some cases (for example, for cardiovascular disease or breast cancer) the evidence is sufficient to give confidence that magnetic fields do not cause the disease. (*Id.* at p. 12.)

Furthermore, in its "Summary and Recommendations for Further Study" WHO emphasized that: "The limit values in [ELF-MF] exposure guidelines [should not] be reduced to some arbitrary level in the name of precaution. Such practice undermines the scientific foundation on which the limits are based and is likely to be an expensive and not necessarily effective way of providing protection." *Id.* at p. 12.

Although WHO recognized epidemiological studies indicate an association on the range of three to four mG, WHO did not recommend these levels as an exposure limit but instead provided: "The best source of guidance for both exposure levels and the principles of scientific review are international guidelines." *Id.* at pp. 12-13. The international guidelines referred to by WHO are the International Commission on Non-Ionizing Radiation Protection ("ICNIRP"), and the Institute of Electrical and Electronic Engineers ("IEEE") exposure limit guidelines to protect against acute effects. *Id.* at p. 12. The ICNIRP-1998 continuous general public exposure guideline is 833 mG, and the IEEE continuous general public exposure guideline in 9,040 mG. In addition, WHO determined that "the evidence for a casual relationship [between ELF-MF and childhood leukemia] is limited, therefore exposure limits based on epidemiological evidence is not recommended, but some precautionary measures are warranted." *Id.* at 355-56.

WHO concluded that:

> given the weakness of the evidence for a link between exposure to ELF magnetic fields and childhood leukemia, and the limited impact on public health, the benefits of exposure reduction on health are unclear and thus, the costs of precautionary measures should be very low… Provided that the health, social and economic benefits of electric power are not compromised, implementing very low-cost precautionary procedures to reduce exposure is reasonable and warranted. (*Id.* at p. 372).

Wisconsin, Minnesota, and California have all conducted literature reviews or research to examine this issue. In 2002, Minnesota formed an Interagency Working Group ("Working Group") to evaluate the body of research and develop policy recommendations to protect the public health from any potential problems resulting from HVTL EMF effects. The Working Group consisted of staff from various state agencies, and it published in September 2002 its findings in "White Paper on Electric and Magnetic Field (EMF) Policy and Mitigation Options (Minnesota Department of Health)." The report summarized the findings of the Working Group as follows:

> Research on the health effects of [MF] has been carried out since the 1970s. Epidemiological studies have mixed results – some have shown no statistically significant association between exposure to [MF] and health effects, some have shown a weak association. More recently, laboratory studies have failed to show such an association, or to establish a biological

> mechanism for how magnetic fields may cause cancer. A number of scientific panels convened by national and international health agencies and the United States Congress have reviewed the research carried out to date. Most researchers concluded that there is insufficient evidence to prove an association between [MF] and health effects; however, many of them also concluded that there is insufficient evidence to prove that [MF] exposure is safe. (*Id.* at p. 1.)

The Public Service Commission of Wisconsin ("PSCW") has periodically reviewed the science on MFs since 1989 and held hearings to consider the topic of MF and human health effects. The most recent hearings on MF were held in July 1998. In January 2008, the PSCW published a fact sheet regarding MFs. In this fact sheet the PSCW noted that:

> Many scientists believe the potential for health risks for exposure to [MFs] is very small. This is supported, in part, by weak epidemiological evidence and the lack of a plausible biological mechanism that explains how exposure to [MFs] could cause disease. The [MFs] produced by electricity are weak and do not have enough energy to break chemical bonds or to cause mutations in DNA. Without a mechanism, scientists have no idea what kind of exposure, if any, might be harmful. In addition, whole animal studies investigating long-term exposure to power frequency [MF] have shown no connection between exposure and cancer of any kind. (PSCW 2008).

The Commission, based on the Working Group and World Health Organization findings, has repeatedly found that "there is insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects." *In the Matter of the Application of Xcel Energy for a Route Permit for the Lake Yankton to Marshall Transmission Line Project in Lyon County*, Docket No. E-002/TL-07-1407, Findings of Fact, Conclusions of Law and Order Issuing a Route Permit to Xcel Energy for the Lake Yankton to Marshall Transmission Project at p. 7-8 (Aug. 29, 2008); *See also*, *In the Matter of the Application for a HVTL Route Permit for the Tower Transmission Line Project*, Docket No. ET-2, E015/TL-06-1624, Findings of Fact, Conclusions of Law and Order Issuing a Route Permit to Minnesota Power and Great River Energy for the Tower Transmission Line Project and Associated Facilities at p. 23 (Aug. 1, 2007)("Currently, there is insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects.").

The Commission again confirmed its conclusion regarding health effects and MFs in the Brookings County – Hampton 345 kV Route Permit proceeding ("Brookings Project"). In the course of the proceeding Applicants Great River Energy and Xcel Energy and one of the intervening parties provided expert evidence on the potential impacts of electric and magnetic fields on human health. The Administrative Law Judge evaluated written submissions and a day-and-half of testimony from the two expert witnesses. The Administrative Law Judge concluded "there is no demonstrated impact on human health and safety that is not adequately addressed by the existing State standards for [EF or MF] exposure." *In the Matter of the Route Permit Application by Great River Energy and Xcel Energy for a 345 kV Transmission Line from Brookings County, South Dakota to Hampton, Minnesota*, Docket No. ET-2/TL-08-1474, ALJ Findings of Fact, Conclusions and Recommendation at Finding 216 (April 22, 2010, and as amended April 30, 2010). The Commission adopted this finding on July 15, 2010. *In the Matter of the Route Permit Application by Great River Energy and Xcel Energy for a 345 kV Transmission Line from Brookings County, South Dakota to Hampton, Minnesota*, Docket No. ET-2/TL-08-1474, Order Granting Route Permit (September 14, 2010).

## 6.6 Stray Voltage

"Stray voltage" is a condition that can occur on the electric service entrances to structures from distribution lines, not transmission lines. More precisely, stray voltage is a voltage that exists between the neutral wire of the service entrance and grounded objects in buildings such as barns and milking parlors.

Transmission lines do not, by themselves, create stray voltage because they do not connect to businesses or residences. Transmission lines, however, can induce stray voltage on a distribution circuit that is parallel to and immediately under the transmission line. Stray voltage issues are not anticipated for the Project.
If stray voltage issues arise as a result of the construction of the Project, the Project will take appropriate measures to address potential stray voltage issues on a case-by-case basis.

## 6.7 Vehicle Use and Metal Buildings Near Power Lines

Passenger vehicles and trucks may be safely used under and near power lines. Due to the location of these lines, there will be minimal vehicle traffic near the lines. However, as with all power lines built by the Company, these lines will be designed to meet or exceed minimum clearance requirements with respect to roads, driveways, cultivated fields, and grazing lands specified by the NESC. Recommended clearances within the NESC are designed to accommodate a relative vehicle height of 14 feet.

Buildings are permitted near transmission lines but are generally discouraged within the right-of-way itself because a structure under a line may interfere with safe operation of the transmission facilities. Due to the location of the lines, we do not anticipate any building other than those at the plant sites to be located near the transmission lines.

## 6.8 Radio and Television Interference

The transmission for the CTs is not expected to cause radio and television interference. Corona from transmission line conductors can generate electromagnetic "noise" at the same frequencies that radio and television signals are transmitted. This noise can cause interference with the reception of these signals depending on the frequency and strength of the radio and television signal. Tightening loose hardware on the transmission line usually resolves the problem. If radio interference from transmission line corona does occur, satisfactory reception from AM radio stations previously providing good reception can be restored by appropriate modification of (or addition to) the receiving antenna system. AM radio frequency interference typically occurs immediately under a transmission line and dissipates rapidly within the right-of-way to either side.

FM radio receivers usually do not pick up interference from transmission lines because corona-generated radio frequency noise currents decrease in magnitude with increasing frequency and are quite small in the FM broadcast band (88-108 Megahertz), and the excellent interference rejection properties inherent in FM radio systems make them virtually immune to amplitude type disturbances.

A two-way mobile radio unit located immediately adjacent to and behind a large metallic structure (such as a steel transmission tower) may experience interference in communicating with another mobile radio unit because of the signal-blocking effects of the structure. Movement of either mobile unit so that the metallic structure is not immediately between the two units should restore communications. This would generally require a movement of less than 50 feet by a mobile unit adjacent to a metallic transmission tower.

Television interference is rare but may occur when a large transmission structure is aligned between the receiver and a weak distant signal, creating a shadow effect. Loose and/or damaged transmission structure hardware may also cause television interference. If television or radio interference is caused by or from the operation of the proposed facilities in those areas where good reception is presently obtained, the Company will inspect and repair any loose or damaged hardware in the transmission line, or take other necessary action to restore reception to the present level, including the appropriate modification of receiving antenna systems if deemed necessary.

## 6.9 Land Requirements

*Black Dog Site*

No new land area will be required as the new CT will be located inside of the existing generation building. Unit 6 will be entirely on land already used for electric power production. Most of the site will be protected to the 100 year flood elevation level, and additional protection will be provided by final grades and equipment elevations. Although protected, the area has a floodplain designation which will be addressed in the Site Permit application based on previous modeling (HEC/RAZ) work.

On-site water storage will include a new tank for storage of treated water for evaporative cooling and other processes. No solid waste will be permanently stored on site. Temporary storage of minor quantities of oily and greasy rags, materials packaging, office waste, domestic-type solid wastes, industrial wastes, universal wastes, and hazardous wastes will occur during operation of Unit 6. As is the case with other similar facilities, the Project is expected to be a very small quantity generator ("VSQG") of hazardous waste.

*Red River Valley Site*

Xcel Energy assessed an approximately 50,000-acre area with a five-mile radius centered on its Hankinson 230 kV substation to site the potential facility location. An exact location of the facility site and total land area required for construction has not yet been determined. The majority of land cover within the evaluation area is active agricultural land. The majority of trees within the area are small, scattered clusters within the Sheyenne National Grassland. There are two cities within the evaluation area. Table 6-12 lists the major land types within the evaluation area, based on USGS Land Use/Land Cover data and National Wetland Inventory (NWI) data.

**Table 6-12**
**Acres of Major Land Types Affected in the Evaluation Area**

| Acres of Major Land Types Affected in the Evaluation Area | | | | | | |
|---|---|---|---|---|---|---|
| **Facility site** | **Agricultural [a]** | **Forest Land** | **Pasture [b]** | **Developed [c]** | **Open Water** | **Wetlands [d]** |
| 5-mile Radius Area | 34,325 | 830 | 7,637 | 3,188 | 947 | 1,053 |
| **Project Total** | **34,325** | **830** | **7,637** | **3,188** | **947** | **1,053** |

[a] Agricultural land includes cultivated row crop fields.

[b] Pasture land includes land used for pasture and hay fields, and herbaceous grassland.

[c] Developed land acreage includes roads, residences, and commercial and industrial buildings.

[d] Wetlands includes forested/shrub wetlands and emergent wetlands. Data is from the National Wetland Inventory database.

Note: Only major land use types are accounted for in this table. The Project totals summed will not add up to the total acreage in the Evaluation area.

A review of FEMA maps was conducted as part of our evaluation. Within the evaluation area, several 100-year floodplain areas occur adjacent to the Wild Rice River, Stacks Slough stream, Willard Lake, Grass Lake, and Lake Elsie.

On-site water storage for the facility site will include a new tank for storage of raw water, and a new tank for storage of treated water for evaporative cooling and other processes. No solid waste will be permanently stored on site. Temporary storage of minor quantities of oily and greasy rags, materials packaging, office waste, domestic-type solid wastes, industrial wastes, universal wastes, and hazardous wastes will occur during the construction and operation of the facility site. As is the case with other similar facilities, the Project is expected to be a VSQG of hazardous waste.

## 6.10 Vegetation and Wildlife

The Black Dog plant is located within the Minnesota and Northeast Iowa Morainal Section (222M), a section within the biogeographic province known as the Eastern Broadleaf Forest Province under the Ecological Classification System ("ECS") developed by the MnDNR and the U.S. Forest Service (MnDNR, 2013). More specifically, the plant is located in an area on the border of the Anoka Sand Plain and the St. Paul Baldwin Plains and Moraines subsections of the Minnesota and Northeast Iowa Morainal Section. The Project site is primarily surrounded by wetland and riparian habitat, providing habitat for many species of plants and animals.

The area for the Red River Valley plant site is located in the Red River Valley and Glaciated Plains physiographic regions of southeastern North Dakota (Bluemle 1989:24). The division is clearly marked by a prominent scarp formed along the western margin of glacial Lake Agassiz. The Red River Valley is characterized by a flat lacustrine plain that developed following the recession of the glacial Lake Agassiz and varies only where Holocene drainages have down cut (NDSHPO 2003:10.1). Gently rolling hills and steep relief characterize the Glaciated Plains and were formed along the glacial ice margin that developed end moraines and eskers. The Project area in North Dakota is primarily northern mixed-grass prairie and is one of the most fertile agricultural areas in the country.

### 6.10.1 Wildlife

*Black Dog Site*

Wildlife commonly found near the Plant site includes a variety of small to medium sized mammals, reptiles and amphibians, birds, and fish. The largest mammal typically found in the area is the white-tailed deer. Other mammals include coyotes, fox, raccoons, beaver, opossum, woodchucks, squirrels, and muskrats. Reptiles near the Plant site include Snapping turtles, Map turtles, Softshell turtles, Painted turtles, gopher snakes, fox snakes, and northern water snakes. Amphibians include leopard frogs, pickerel frogs, spring peeper, and American toads. Fish species vary depending on the type of water body. The most commonly distributed fish species in the area include largemouth bass, sunfish, crappies, northern pike, and multiple species of rough fish such as carp and suckers. Bird species include eagles, turkeys, hawks, pheasants, ducks, herons, and multiple species of song birds.

Because the Plant is located within an urban area, the fauna generally present are adapted to high levels of anthropogenic disturbance. Further, the existing Black Dog Plant provides little to no habitat for wildlife species. Since all facilities for the Project will be constructed on the existing plant site, it is unlikely that the construction, operation, and maintenance of the Project would have an effect on fauna present in the area.

*Red River Valley Site*

Wildlife that commonly occurs near or in the evaluation area include small to medium sized mammals, reptiles and amphibians, birds, and fish. Common mammals that frequent the area could include white-tailed deer, squirrels, rabbits, opossums, coyotes, fox, or raccoons. Fish, reptiles, and amphibians found in the area will vary and will most likely occur in areas adjacent to or in the Wild Rice River, and intermittent streams, lakes, and wetland complexes. Birds and waterfowl that occur in the evaluation area include, but are not limited to, raptors, ducks, geese, cranes, and multiple species of song birds. Because the evaluation area is located within active agricultural land, the fauna generally present are adapted to high levels of anthropogenic disturbance. Therefore, it is unlikely that any disturbances within the evaluation area would have an effect on fauna present in the area.

### 6.10.2 Waterbodies

*Black Dog Site*

The majority of the Black Dog Plant site is located in a Zone A20, or 100 year, floodplain (FEMA, 1977). A small portion of the railroad spur is located in a Zone B, or 500 year, floodplain.

The plant site is located in the Black Dog Lake – Minnesota River watershed (USDA, 2011). A watershed is defined as the entire physical area or basin drained by a distinct stream or riverine system, physically separated from other watersheds by ridgetop boundaries (MnDNR, 2011).

As part of the Metropolitan Surface Water Management Act, the Black Dog Watershed Management Organization ("BDWMO") was formed (BDWMO, 2011). Watershed management overseen by the BDWMO covers northwestern Dakota County and a portion of northeastern Scott County, Minnesota. The BDWMO contains portions of the cities of Apple Valley, Burnsville, Eagan, Lakeville, and Savage. Surface water in the BDWMO ultimately discharges to the Minnesota River.

The plant site is surrounded by several significant surface water features that include the Minnesota River and Black Dog Lake. Some of these waterbodies are also classified by the MnDNR as Minnesota public water basins and watercourses that meet the criteria set forth in Minnesota Statutes Section 103G.005, subdivision 15, and are identified on Public Water Inventory ("PWI") maps authorized by

Minnesota Statutes, Section 103G. Per the NPDES permit, Black Dog Lake is referred to as a lotic system cooling lake for thermal discharges only.

*Red River Valley Site*

The evaluation area is located within two watersheds. The Western Wild Rice Watershed (HUC9020105) comprises the majority of the evaluation area while the Bois De Sioux Watershed (HUC9020101) is located on the very southern edge of the evaluation area below the City of Hankinson.[1]

The Wild Rice River flows through the northern half of the evaluation area and is listed as impaired (waterbody id: ND-09020105-009-S_00) due to fecal coliform, dissolved oxygen, physical substrate habitat alternations, and sedimentation.[2] The Stacks Slough stream traverses through the southern half of the evaluation area. There are several unnamed stream systems within the evaluation area.

The evaluation area encompasses three lakes: Willard Lake, Grass Lake, and Lake Elsie. Lake Elsie is listed as impaired due to sedimentation.[1] All three lakes are located southwest of the city of Hankinson and are adjacent to each other. Based on a review of NWI data, approximately 1,053 acres of wetlands are present within the evaluation area.

Xcel Energy will design the project scope to minimize to the greatest extent possible direct and indirect impacts on waterbodies (e.g., erosion runoff). Xcel Energy will apply erosion control measures such as using silt fence to minimize impacts to adjacent water resources. During construction, Xcel Energy will control operations to minimize and prevent material discharge to surface waters. Disturbed surface soils will be stabilized at the completion of the construction process to minimize the potential for subsequent effects on surface water quality.

Xcel Energy is currently determining specific engineering details for the facility site. Facilities are not expected to be sited within wetlands and/or waterbodies. However, if dredge and fill activities became necessary within jurisdictional wetlands and/or waterbodies, Xcel Energy would obtain approvals from the USACE and/or the North Dakota Department of Health, if necessary, under Sections 401 and 404 of the Clean Water Act.

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[1] http://mapservice.swc.state.nd.us/floodplain.html

[2] http://ofmpub.epa.gov/waters10/attains_waterbody.control?p_list_id=ND-09020105-009-S_00&p_report_type=T&p_cycle=2012#causes

### 6.10.3 Vegetation Cover

*Black Dog Site*

Historically, this area was primarily floodplain and terrace forests of silver maple, cottonwood, box-elder, green ash and elm within and along the terrace forests river valley. Wetland complexes associated with the Minnesota River Valley system are present throughout the area. Many of the native species remain although many wetlands are dominated by invasive species such as reed canary grass or purple loose-strife.

Because the Project will be constructed within the existing Plant footprint and adjacent to an existing, active railroad line, as well as within an area populated by transmission lines and structures, the Project impacts to vegetation will be minor.

*Red River Valley Site*

The majority of land in Richland County has been used for agriculture since the late 19th century. Currently, most of the land cover in the evaluation area is cultivated agricultural land. Wetland complexes that occur in the area are associated with the riparian boundaries of the Wild Rice River, intermittent streams, and lakes. Any wetland complex present within the evaluation area will likely be avoided by construction and not impacted.

Short-term impacts from construction on agricultural land could include the loss of standing crops within soil disturbing activities and disruption of farming operations. The majority of trees within the facility site are in small scattered clusters throughout the evaluation area and within the Sheyenne National Grassland.

### 6.10.4 Threatened and Endangered Species

*Black Dog Site*

<u>U.S. Fish and Wildlife Service</u>
The U.S. Fish and Wildlife Service ("FWS") website was reviewed for a list of species covered under the Endangered Species Act ("ESA") that may be present within Dakota County. According to the website, the following two federally listed species are known to occur within the county: Higgins eye pearlymussel (*Lampsilis higginsii*) and prairie bush-clover (*Lespedeza leptostachya*).

The Higgins eye pearly mussel is listed as endangered and occurs only within the Mississippi River and the lower portion of some of its larger tributaries. The Project will not be located at the Mississippi River. Therefore, it was determined that the Project will have no effect on the Higgins eye pearly mussel or its habitats.

The prairie bush-clover is listed as threatened and occurs within native dry mesic-prairies where the soils are well-drained with high sand or gravel content. The Project is confined to an existing Plant site. Therefore, it has been determined the Project will have no effect on the prairie bush-clover or its habitat.

<u>State of Minnesota</u>
A request for a MnDNR Natural Heritage Information System ("NHIS") search and comments regarding rare species and natural communities for the Project area was submitted to the MnDNR on January 11, 2011. In a letter dated March 8, 2011, MnDNR identified within the Project area Bulrush Marsh native plant communities and peregrine falcons *(Falco peregrinus)*, a state-listed threatened species. The MnDNR recommended mitigation measures for the Bulrush Marsh and concluded that the Project will not likely affect the peregrine falcons. A review of the NHIS database, completed in February 2013, confirmed there have been no changes within the Project area.

*Red River Valley Site*

<u>U.S. Fish and Wildlife Service</u>
The FWS website was reviewed for a list of species protected under the ESA that may be present within Richland County. According to the website, the federally listed whooping crane (*Grus americana*) and the Western prairie fringed orchid (*Platanthera praeclara*) are known to occur within the county.

Whooping cranes occur in wetland and mosaic habitats and shallow waters. They use cropland and wetland areas as stopover locations to feed and rest. If individuals are migrating through the project area during construction, they would likely avoid the area and use adjacent croplands and wetland areas. The FWS's standard mitigation recommendation is for the construction company to coordinate with the FWS to identify appropriate impact minimization measures when a whooping crane is identified within 1 mile of a construction area. Xcel Energy will follow standard mitigation procedures in coordination with the FWS. Western prairie fringed orchids occur in wet prairies and sedge meadows. The evaluation area is primarily comprised of agricultural land and developed areas.

Impacts on suitable habitat for the western prairie fringed orchids present within the evaluation area would likely be avoided by construction.

State of North Dakota

Although North Dakota does not have a state endangered or threatened species list, Xcel Energy will consult with the following agencies, if necessary, to fulfill other state permit requirements:

- North Dakota State Game and Fish Department's Nongame Program for review of species of conservation priority, habitats of concern, or state-owned lands; and
- North Dakota Parks and Recreation for review of plant or animal species of concern, other significant ecological communities, and lands owned or managed by the agency.

## 6.11 Human Settlement

*Black Dog Site*

In prehistoric and the early historic periods, the bluffs above the river were the preferred location for settlement. Human groups utilized the resources in the bottomlands and wetlands, but they did not spend significant time or routinely leave behind evidence of their presence there (Merjent, Inc., Phase 1a Literature Review for the Xcel Energy Proposed Black Dog Repower Project, Dakota County, Minnesota, December 30, 2010). Today, the study area is almost entirely limited to industrial infrastructure.

According to U.S. Census Bureau data, and as shown in Table 6-13, minority groups in the area constitute only a small percentage of the total population. Per capita incomes within the county and nearest cities to the plant site are higher than for the State of Minnesota. The average percentage of persons living below the poverty level in the area is less than the State average. The area does not contain disproportionately high minority populations, low-income populations, or high percentages of persons living below the poverty level.

**Table 6-13**
**Black Dog Site Population and Economic Characteristics**

| Location | Population | Minority Population (Percent) | Caucasian Population (Percent) | Per Capita Income | Percentage of Individuals Below Poverty Level |
|---|---|---|---|---|---|
| State of Minnesota | 5,303,925 (2010) [a] 5,379,139 (2012) [b] | 13.1% (2011) [b] | 86.9% (2011) [b] | $30,310 (2011) [b] | 11% (2011) [b] |
| Dakota County | 402,006 (2011) [c] | 12.6% (2011) [c] | 87.4% (2011) [c] | $34,822 (2011) [c] | 6% (2011) [c] |
| City of Burnsville | 60,828 (2011) [d] | 22.5% (2010) [d] | 77.5% (2010) [d] | $32,164 (2011) [d] | 9.2% (2011) [d] |
| City of Eagan | 64,765 (2011) [e] | 18.5% (2010) [e] | 81.5% (2010) [e] | $40,213 (2011) [e] | 5.5% (2011) [e] |

Sources:

[a] U.S. Census Bureau. 2010 U.S. Census, Resident Population Data, Population Density. http://www.census.gov/2010census/popmap/ipmtext.php?fl=27. Accessed February 2013.

[b] U.S. Census Bureau. State and County QuickFacts. Minnesota. Available online at http://quickfacts.census.gov/qfd/states/27000.html. Accessed February 2013.

[c] U.S. Census Bureau. State and County QuickFacts. Dakota County, Minnesota. Available online at http://quickfacts.census.gov/qfd/states/27/27037.html. Accessed February 2013.

[d] U.S. Census Bureau. Population Finder. Burnsville City, Minnesota. Available online at http://quickfacts.census.gov/qfd/states/27/2708794.html. Accessed February 2013.

[e] U.S. Census Bureau. Population Finder. Eagan City, Minnesota. Available online at http://quickfacts.census.gov/qfd/states/27/2717288.html. Accessed February 2013.

The Project is not located in an agricultural area. Based on recent aerial photographs, the nearest significant tracts of land with evidence of agriculture are south of the City of Apple Valley, approximately 6 miles from the Project.

There are no forested areas where species are harvested within the plant's boundaries. The primary tree cover in the area is associated with waterways and along the Xcel Energy railroad spur. No economically significant forestry resources are located along the proposed new transmission lines route.
The Minneapolis – St. Paul International Airport ("MSP") is located approximately 3.3 miles north of the property boundaries. The applicable Standards for Determining Obstructions only apply to structures within the three mile radius of an airfield.

According to the Minnesota Department of Transportation county pit map for Dakota County and USGS topographic maps, there are no gravel pits, rock quarries, or commercial aggregate sources in the vicinity of the plant boundaries (http://www.dot.state.mn.us/maps/cadd/county/dakota.pdf). Because no existing gravel and rock resources are being utilized within the area, no impacts are anticipated. Unknown resources that may exist in the area would be situated in close proximity to existing utility and roadway rights-of-way, making development unlikely.

*Red River Valley Site*

Settlers first came to North Dakota in the 1870s and 1880s to farm wheat. Today, the area is still used for agricultural purposes and is now farmed for corn, soybeans, and sunflowers in addition to wheat. There are two cities, Hankinson and Great Bend, within the evaluation area and one city, Mantador, on the northwestern border of the evaluation area. The City of Hankinson was founded in the 1870s, although settlers were present in the area before that time[3]. Today, there are numerous residences, farmsteads, and businesses scattered throughout the evaluation area.

According to U.S. Census Bureau data, and as shown in Table 6-14, minority groups in the surrounding cities constitute only a small percentage of the total population, averaging 7 percent. Per capita income within Richland County is lower than for the State of North Dakota; however, the poverty level for Richland County is lower than the State of North Dakota. Data describing the average Per Capita Income and Poverty Levels for the cities within the facility site are unavailable. The area does not contain disproportionately high minority populations, low-income populations, or high percentages of persons living below the poverty level.

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3 http://www.hankinsonnd.com/

**Table 6-14**
**Evaluation Area Population and Economic Characteristics**

| Location | Population | Minority Population (Percent) | Caucasian Population (Percent) | Per Capita Income | Percentage of Individuals Below Poverty Level |
|---|---|---|---|---|---|
| State of North Dakota | 672,591 (2010) [a]<br>699,628 (2012) [b] | 9.6% (2011) [b] | 90.4% (2011) [b] | $27,305 (2011) [b] | 12.3% (2011) [b] |
| Richland County | 16,217 (2012) [c] | 5.1% (2011) [c] | 94.9% (2011) [c] | $25,835 (2011) [c] | 10.6% (2011) [c] |
| Great Bend City | 60 (2010) [d] | 0% (2010) [d] | 100% (2010) [d] | NA | NA |
| Hankinson City | 919 (2010) [e] | 6% (2010) [e] | 94% (2010) [e] | NA | NA |
| Mantador City | 64 (2010) [f] | 8% (2010) [f] | 92% (2010) [f] | NA | NA |

Sources:

[a] U.S. Census Bureau. 2010 U.S. Census, Resident Population Data, Population Density. http://www.census.gov/2010census/popmap/ipmtext.php?fl=27. Accessed April 2013.

[b] U.S. Census Bureau. State and County QuickFacts. North Dakota. Available online at http://quickfacts.census.gov/qfd/states/38000.html. Accessed April 2013.

[c] U.S. Census Bureau. State and County QuickFacts. Richland County, North Dakota. Available online at http://quickfacts.census.gov/qfd/states/38/38077.html. Accessed April 2013.

[d] U.S. Census Bureau. American FactFinder. Great Bend City, North Dakota. Available online at http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=bkmk. Accessed April 2013.

[e] U.S. Census Bureau. American FactFinder. Hankinson City, North Dakota. Available online at http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=bkmk. Accessed April 2013.

[f] U.S. Census Bureau. American FactFinder. Mantador City, North Dakota. Available online at http://factfinder2.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=bkmk. Accessed April 2013.

The evaluation area is comprised mainly of active agricultural land, and land used for pasture and hay fields. The majority of agricultural land is located in the northern and eastern halves of the evaluation area. Short-term impacts from construction on agricultural land could include the loss of standing crops within soil disturbing activities and disruption of farming operations.

There are no forested areas within the evaluation area that are being harvested commercially. The primary type of tree species within the evaluation area is deciduous. No economically significant forestry resources are located within the evaluation area.

There are multiple federal and state managed lands within the evaluation area. The evaluation area crosses areas within the Sheyenne National Grassland, the Lake Elsie National Wildlife Refuge, the Stack Slough State Wildlife Management Area, the Mud Lake State Wildlife Management Area, and waterfowl area managed by the Tewaukon Wetland Management District. These designated lands are located southwest of Hankinson except for the Sheyenne National Grassland, which is located in the central western portion of the evaluation area. Xcel Energy recognizes the biological importance of these designated areas and will avoid constructing within the boundaries and within close proximity to the boundaries of these areas.

Based on a desktop review, there are no active gravel pits, rock quarries, or commercial aggregate sources or mineral resources within the evaluation area. Because no active gravel and rock resources are being utilized within the area, no impacts are anticipated.

There are two cities, Hankinson and Great Bend, within the evaluation area and one city, Mantador, on the northwestern border. Since there are cities within and surrounding the evaluation area, there are numerous residential, commercial, and industrial buildings. Other sensitive developed areas within the evaluation area include cemeteries, schools, and churches. Xcel Energy will take these developed and sensitive areas into account when determining the location of the facility site.

## 6.12 Archeological and Historic Resources

*Black Dog Site*

In December 2010, a review of hard copy records maintained at the Minnesota State Historic Preservation Office ("SHPO") identified two archaeological sites and one inventoried historic architectural property located within one mile of the Plant site. In February 2013, a second review of the SHPO records, this time utilizing records available in their GIS database, identified three additional cultural resources within one mile of the Project, including one historic property listed on the National Register of Historic Places ("NRHP"). A summary of the inventoried cultural resource sites is provided in Table 6-15.

**Table 6-15**
**Previously Identified Historic Properties near the Plant Site**

| Type of Historic Property | Inventory Number | Description | NRHP Status |
|---|---|---|---|
| Archaeological | 21HE0001 | Contact Period, Davis Mound (part of 21HE0012) | Unevaluated |
| Archaeological | 21HE0013 | Prehistoric, Findlay Mounds – Group No. 2 | Unevaluated |
| Archaeological Lead | 21HEbl | Contact Period, Oak Grove Indian Mission Cemetery | Unevaluated |
| Archaeological | 21DK0041 | Prehistoric Arvilla Complex mound site | Destroyed |
| Architectural/ Archaeological | HE-BLC-020/ 21HE0244 | Gideon H. Pond House | NRHP Listed |
| Architectural | N/A | Union Pacific Railroad | Potentially eligible |

Three of the archaeological sites are mound sites, confirmed as burials by excavation, and a fourth is the unconfirmed location of the Oak Grove Indian Mission Cemetery. Site 21DK0041, which was dated to the prehistoric Arvilla Complex (AD 500-900), has been destroyed, and the remaining sites are located on the river bluff more than one-half mile north and west of the Project area. Since all of the sites are located outside of the construction footprint, they will not experience direct impacts resulting from the construction of this Project.

Two historic architectural properties, the Gideon Pond House and the Union Pacific Railroad, are located within one mile of the plant boundaries. The Gideon Pond House is a private residence that was built in the mid-nineteenth century and listed on the NRHP on July 1970. It is located on the river bluff approximately one mile west of the project area and will not experience adverse view shed effects by construction of this Project.

The Union Pacific Railroad, which runs along the southern edge of the Minnesota River Valley, was first built in 1864. This rail line between St. Paul and Mankato, represents the early expansion of Minnesota and the transportation network that helped bring the state's agricultural products to the marketplace. A Multiple Property Nomination to the NRHP for Railroads in Minnesota 1862-56 (Schmidt et al., 2002) establishes the criteria for NRHP eligibility for railroad properties. Although the Union Pacific Railroad is not specified as eligible for listing on the NRHP, it does meet the criteria and should be considered potentially eligible.

The Union Pacific Railroad is on the southern edge of the construction footprint, but will not be directly impacted by proposed construction. The proposed construction is an in-kind expansion of the existing built environment and will not create new indirect visual impacts.

*Red River Valley Site*

A desktop review to assess the likelihood that the facility site would affect unknown cultural resources was conducted within the evaluation area. The evaluation area is located on a beach ridge overlooking lacustrine plain of glacial Lake Agassiz. The meandering Wild Rice River cuts through the northern half of the evaluation area, while Stacks Slough flows through the southern half and divides the glacial plain from the pitted outwash terrain to the southwest. Prehistoric populations likely took advantage of the various subsistence resources available along the Wild Rice River and pothole lakes. Except for the Sheyenne National Grasslands area, the evaluation area has been actively cultivated for over one hundred years, thereby disturbing near-surface cultural deposits; however, there is a very slight potential for intact cultural horizons that were buried by alluvial deposition from annual flooding. The North Dakota SHPO has recorded few archaeological sites within this setting and as a result, the potential for impacting unrecorded prehistoric archaeological resources within the Evaluation area is generally low, but increases nearer Wild Rice River.

Other historical documents relevant to the evaluation area were reviewed in order to identify possible unrecorded historic sites that might be affected by the Facility site. A review of the NRHP did not identify any state- or NRHP-listed property within the Evaluation area. General Land Office ("GLO") Survey maps, representing the original township surveying of the territory between 1871 to 1884, were viewed online through the North Dakota State Water Commission website. The GLO maps show numerous small parcels surrounding Willard and Grass Lakes, as well as an early road or Indian/pioneer trail that extends northeast across the Evaluation area, being situated on the north side of Willard Lake and running south of Wild Rice River toward Breckenridge. This trail does not appear on current maps of the evaluation area. Historic plat maps, and modern aerial photographs and topographic maps viewed online identified several farmsteads dating from the late nineteen century within the evaluation area. There is a potential the plant site will create new permanent visual impacts to these historic farmsteads. The only known historic architectural property within the vicinity of the evaluation area is the Soo Line Railroad, which runs northwestward from the Hankinson; it will not be impacted by proposed construction.

## 6.13 Traffic and Transportation Infrastructure

*Black Dog Site*

During construction of the Project, there will be an increase in traffic on the roadways into the plant. Minor temporary road upgrades may be necessary to facilitate delivery of equipment and materials for the Project. Some equipment and materials for construction of the Project will be delivered by rail. During construction, barge delivery is also an option but is not anticipated to be significant. Operation of the Project will result in a decrease in traffic from current traffic levels. The existing roads and rail yard will meet the Project access needs during future operations.

*Red River Valley Site*

Many roads and highways traverse through the evaluation area including Interstate 29 and Highway 11, which are high traffic roadways. During construction of the Project, there will be an increase in traffic on the roadways into the site. Minor temporary road upgrades may be necessary to facilitate delivery of equipment and materials for the Project. Operation of the Project will result in an increase in traffic from current traffic levels.

## Appendix A
## Peak Demand and Annual Consumption Forecast

### Forecast Methodology

*Overall Methodological Framework*

Xcel Energy prepares its forecast by major customer class and jurisdiction, using a variety of statistical and econometric techniques. The NSP System serves five jurisdictions. Minnesota, North Dakota and South Dakota are served by Northern States Power Company. Wisconsin and Michigan are served by Northern States Power Company, a Wisconsin corporation (NSPW). The overall methodological framework is "model oriented". The NSP and NSPW Systems operate as an integrated system. The forecast is referred to as the 2012 Budget Update (Fall 2011).

*Specific Analytical Techniques*

1. Econometric Analysis. Xcel Energy uses econometric analysis to develop jurisdictional MWh sales forecasts at the customer meter for the following sectors:
   a. Residential without Space Heating;
   b. Residential with Space Heating;
   c. Small Commercial and Industrial;
   d. Large Commercial and Industrial.

   Xcel Energy also uses econometric analysis to develop the total system MW demand forecast.
2. Trend analysis is used for the "Other" sectors, which includes Public Street and Highway Lighting, Other Sales to Public Authorities, Interdepartmental sales, and Municipals (firm Wholesale).
3. Loss Factor Methodology. Loss factors by jurisdiction are used to convert the sales forecasts into system energy requirements (at the generator).
4. Judgment. Judgment is inherent to the development of any forecast. Whenever possible, Xcel Energy uses quantitative models to structure its judgment in the forecasting process.

The sales forecasts are estimates of MWh levels measured at the customer meter. They do not include line or other losses. The various jurisdictional class forecasts are summed to yield the total system sales forecast. Native energy requirements are measured at the generator and include line and other losses. Xcel Energy creates native energy requirements based on the sales forecasts. A system loss factor for each jurisdiction, developed based on average historical losses, is applied to the jurisdictional sales forecast to calculate total losses. The sum of the jurisdictional MWh sales plus losses equals native energy requirements. The native energy requirements, along with peak producing weather and binary variables, are then used as independent variables within an econometric model to forecast MW peak demand for the Xcel Energy North System.

*Models Used*

1. Residential Econometric Models. Sales to the residential sectors represent 28.8 percent of total NSP System electric sales in 2010. Residential sales are divided into with space heating and without space heating customer classes for each jurisdiction. Regression models using historical data are developed for each residential sector. A variety of independent variables are used in the models, including:
    - Number of customers;
    - Gross Metro Product for respective jurisdiction;
    - Actual heating and temperature humidity index (THI) degree days;
    - Number of monthly billing days.

2. Small Commercial and Industrial Econometric Models. The small commercial and industrial sector represents 42.2 percent of NSP System electric sales in 2010. The models are regressions using historical data. The models include a combination of variables, including the following:
    - Number of small commercial and industrial customers;
    - Gross Metro Product for respective jurisdiction;
    - Employment for respective jurisdiction;
    - Actual heating and temperature humidity index (THI) degree days.

3. Large Commercial and Industrial Econometric Models. Sales to the large commercial and industrial sector represent 26.3 percent of NSP System electric sales in 2010. The models are regressions using historical data and a combination of variables, including the following:
    - Industrial Production for respective jurisdiction;
    - Employment for respective jurisdiction;
    - Number of monthly billing days;
    - Indicator variables such as CI reclassification.

4. Others. Sales to the "Others" sector represent 0.7 percent of NSP System electric sales in 2010. This sector includes Public Street and Highway Lighting (PSHL),

Sales to Public Authorities (OSPA) and Interdepartmental IDS) sales. Because this class represents a very small portion of the total sales, trend analysis is used and very little growth is forecast.

5. Municipals. Sales to the Municipal utility sector represent 2.0 percent of NSP System electric sales in 2010. The municipal class is forecast using separate trend analysis at the individual customer level for NSP and NSPW. The forecast of these municipal customers only includes firm wholesale customer usage.

6. Peak Demand Model. An econometric model is developed to forecast base peak demand for the entire planning period. The model includes a combination of variables, including the following:
   - Weather normalized native energy requirements;
   - Peak producing weather by month;
   - Binary variables.

**Methodology Strengths and Weaknesses**

The strength of the process Xcel Energy uses for this forecast is the richness of the information obtained during the analysis. Xcel Energy's econometric forecasting models are based on sound economic and statistical theory. Historical modeling and forecast drivers are based on economic and demographic variables that are easily measured and analyzed. The use of models by class and jurisdiction gives greater insight into how the NSP System is growing, thereby providing better information for decisions to be made in the areas of generation, transmission, marketing, conservation, and load management.

With respect to accuracy, forecasts of this duration are inherently uncertain. Planners and decision makers must be keenly aware of the inherent risk that accompanies long-term forecasts. They must also develop plans that are robust over a wide range of future outcomes.

**Data Definitions**

The following is a list of definitions of the variables considered in Xcel Energy's econometric models.

**Jurisdiction Abbreviations**

| | |
|---|---|
| M or MN | State of Minnesota |
| N or ND | State of North Dakota |

S or SD State of South Dakota
W or WI State of Wisconsin
Mi or MI State of Michigan

**Monthly MWh Sales Series**

SLSReswo(Juris) Residential without space heating for given jurisdiction
SLSResSH(Juris) Residential with space heating for given jurisdiction
SLSSmCI(Juris) Small commercial and industrial for given jurisdiction
SLSLgCI(Juris) Large commercial and industrial for given jurisdiction

**Monthly Customer Series**

CustReswo(Juris) Residential without space heating for given jurisdiction
CustResSH(Juris) Residential with space heating for given jurisdiction
CustSmCI(Juris) Small commercial and industrial for given jurisdiction
CustLgCI(Juris) Large commercial and industrial for given jurisdiction

**Monthly Economic and Demographic Series**

(Juris)HH Number of Households in given jurisdiction
(Juris)NR Total Population in given jurisdiction
GMP(MSA) Gross Metro Product for given metropolitan statistical area
GSP(State) Gross State Product for given state
EE_(Juris) Total employment in given jurisdiction
EEMFG_(Juris) Manufacturing employment in given jurisdiction
IPMFG_(Juris) Industrial Production Index - manufacturing in given jurisdiction
IPSB0004_US Industrial Production Index – United States
CYP_(Juris) Real Personal Income in given jurisdiction
CYPNR_(Juris) Real per capita Personal Income in given jurisdiction
(Juris)TotRes_RAP Real Average Price for electric sales to residential customers

**Monthly Data Variables used in Demand Model**

THI12(Month)Cust Temperature Humidity Index @12:00 noon multiplied by total retail customers

THI12_LAG1(Month)Cust Temperature Humidity Index @12:00 noon on the day before the peak day multiplied by total retail customers.

THI15(Month)Cust Temperature Humidity Index @15:00 (3:00 PM) on the peak day multiplied by total retail customers

HDD(Season) Normal Heating Degree Days on the day of the Peak multiplied by a binary variable for the season (winter – Wtr, shoulder month – sh)

DaysOver90(Month) cumulative days over 90 for the calendar year as of the monthly peak day

WNActEnergy_LpYrAdj_12MoSum 12 month rolling sum of the weather normalized net energy requirements adjusted to remove the effect of leap years

MfgSlowdown An index based on Industrial (Manufacturing) Production and Manufacturing Employment

**Monthly Weather Variables**

H65_bill (Juris) (Month) HDD base 65 for given jurisdiction and month

T65_bill (Juris) (Month) THI DD base 65 for given jurisdiction and month

**Other Monthly Variables**

BillDaysCellnet21 Billing Month Days

**Monthly Binary Variables**

| | |
|---|---|
| Jan | Binary variable for the month of January |
| Feb | Binary variable for the month of February |
| Mar | Binary variable for the month of March |
| Apr | Binary variable for the month of April |
| May | Binary variable for the month of May |
| Jun | Binary variable for the month of June |
| Jul | Binary variable for the month of July |
| Aug | Binary variable for the month of August |
| Sep | Binary variable for the month of September |
| Oct | Binary variable for the month of October |

| | |
|---|---|
| Nov | Binary variable for the month of November |
| Dec | Binary variable for the month of December |

Xcel Energy uses internal and external data to create its MWh sales and MW peak demand forecast.

Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. Historical coincident net peak demand data is obtained through company records. The load management estimate is added to the net peak demand to derive the base peak demand.

The Company relies on weather data (dry bulb temperature and dew points) collected from official NOAA weather reporting stations for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. The data is collected from weatherunderground.com for these locations. The heating degree-days and THI degree-days are calculated internally based on this weather data.

Economic and demographic data is obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically they are accessed from IHS Global Insight, Inc. data banks, and reflect the most recent values of those series at the time of modeling.

**Demand-Side Management Programs**

The regression model results for the residential and commercial and industrial classes are reduced to account for the expected incremental impacts of demand-side management ("DSM") programs. An annual forecast of the impact of new DSM programs (excluding Saver's Switch) is developed by Xcel Energy's DSM Regulatory Strategy and Planning Department. The resulting sales volumes are used to reduce the class level sales forecasts that result from the regression modeling process. Impacts from all program installations through 2010 are assumed to be imbedded in the historical data, so only new program installations are included in the DSM adjustment.

An additional adjustment was made to the Fall 2011 forecast to account for new federally mandated efficiency standards for business cooling. This new standard supplants DSM programs the Company previously had in place, which reduces the amount of Business DSM. However, the standards have not been in place long enough to be reflected in actual sales data used in the development of the forecast. The solution to this problem was to adjust forecasted Commercial/Industrial sales downward to incorporate the effect of the new standards.

The Company's Saver's Switch program results in short-term interruptions of service designed to reduce system capacity requirements rather than permanent reductions in energy use, so it is not considered here.

**Overview of Probability Distributions**

Xcel Energy uses a straightforward extension of the peak demand econometric model to assess risk around the expected value of the peak demand by conducting a Monte Carlo simulation on the main drivers of the peak model (weather and native energy requirements). For the Monte Carlo energy probability distribution model, the main drivers are weather and Minnesota Households (HH_MN).

The Monte Carlo stochastic simulation of peak demand (MW) or (energy (MWh)) involves taking 10,000 random draws from the weather probability distributions as well as 10,000 draws from the 12-month sum of energy probability distribution (or HH_MN probability distribution), which, in turn, produces 10,000 forecasts of peak demand (or energy), and thus generates a probability distribution around the mean peak demand (or mean energy).

For example, if the econometric model forecasts that the mean peak demand for 2022 is 9,969 MW, then using the same econometric model, the Monte Carlo simulation method forecasts that there is a 90percent probability that the 2022 peak demand will be less than 11,187 MW, or alternatively, a 10percent chance that the peak will be less than 8,730 MW.

In summary, the Monte Carlo stochastic simulation method adequately captures the effect of extreme weather on monthly peak demand and monthly energy usage, while preserving the expected value or mean forecast of peak demand and energy.

**Data Adjustments and Assumptions**

1. Weather Adjustments. Xcel Energy adjusts the monthly weather data to reflect billing schedules. Therefore, the monthly weather data corresponds exactly with the billing month schedule.

2. Economic Adjustments. All price data and related economic series are deflated to 2005 constant dollars.

## Assumptions and Special Information

The data used in Xcel Energy's forecasting process has already been discussed in a general way. Descriptions and citations of sources for the data sets have been mentioned within this documentation under different sections.

Xcel Energy believes that its process is a reasonable and workable one to use as a guide for its future energy and load requirements. The underlying assumptions used to prepare Xcel Energy's median forecast are as follows:

1. Demographic Assumption. Population or household projections are essential in the development of the long-range forecast. The forecasts of customers are derived from population and household projections provided by IHS Global Insight, Inc., and reviewed by Xcel Energy staff. Xcel Energy customer growth mirrors demographic growth over the forecast period.

2. Weather Assumption. Xcel Energy assumes "normal" weather in the forecast horizon. Normal weather is defined as the average weather pattern over the 20-year period from 1991-2010. The variability of weather is an important source of uncertainty. Xcel Energy's energy and peak demand forecasts are based on the assumption that the normal weather conditions will prevail in the forecast horizon. Weather-related demand uncertainties are not treated explicitly in this forecast.

3. Loss Factor Assumptions. The loss factors are important to convert the sales forecast to energy requirements. Xcel Energy uses a historical average loss factor for each jurisdiction, and assumes it will not change in the future.

4. Large Customer Assumptions. The model results have been adjusted to account for announced changes in operations for several large customers.

5. Alternate Energy Sources/Fuel Conversion Assumptions. The availability of alternate sources of energy was not a factor considered in our econometric model. However, in the Strategist modeling done in the resource plan, the net total demand by customers is adjusted to account for the roof top solar installations funded through our Solar*Rewards program. Our forecast assumptions also did not include any specific inputs regarding conversion from other fuels to electricity or vice versa. While we forecast residential sales and residential customer counts separately for the with-space-heating class and the without-space-heating class, we make no explicit adjustment to account for customers switching between the two classes.

6. Electricity Prices. The Company expects the future price of electricity to increase. The prices used in the forecasting process are developed based on historical actual prices calculated as revenues divided by sales. A price escalator is then used to project prices in the future. The price escalator used in the development of this forecast was the U.S. Producer Price Index for electric power. Given the inverse relationship between price and demand, the projected increasing prices will likely result in lower system demand as compared to a situation where projected prices are flat or declining.

7. Data Availability. Subpart 2 B requests data that is not available historically or not generated by the Company in preparing its own internal forecast. This includes annual energy consumption and peak demand for the categories farm, irrigation and drainage pumping, commercial, mining, and industrial. The Company does not track consumption or demand based on the type of business activity, but rather based on rate classes. The Company's rate classes are grouped into Small Commercial and Industrial, for customers with demand less than 1,000 kW, and Large Commercial and Industrial for customers with demand greater than 999 kW. The Small Commercial and Industrial consumption and demand have been reported in the commercial category and the Large Commercial and Industrial consumption and demand have been reported in the industrial category.

   Subpart 2 E requests the estimated annual revenue requirement per kilowatt hour for the system in current dollars. This information is not generated by the Company in preparing the internal forecast. As explained above, the electricity price forecast is based on the U.S. Producer Price Index for electric power.

   Subpart 2 F requests estimated average system weekday load factor by month. The Company does not have this information available, and instead has provided average system load factors by month.

**Forecast Coordination**

Xcel Energy reports its energy and peak demand forecasts to the Midwest ISO (MISO). MISO then combines the forecasts of all its member utilities. Xcel Energy also reports its forecast to the Public Service Commission of Wisconsin as part of its Strategic Energy Assessment (SEA) process. In this process, the Wisconsin portion of the total Xcel Energy system load is combined with other Wisconsin electric utilities to form a statewide Wisconsin forecast.

## Forecast Vintage Comparison

As described above, projections of energy and demand are fundamental to identifying the need for generation resources. Thus, these forecasts are an important component in determining the size, type and timing of new generation resources. As a result, ensuring robust forecasts with fully analyzed assumptions and variables is a key component to analyzing a Resource Plan or Certificate of Need.

*Forecast Vintage and Comparison*

The review process for a Resource Plan or a Certificate of Need typically takes a significant amount of time and effort to complete. During this time, forecasts can change as economic variables change. The graphs below compare the peak demand and energy of the Company's Fall 2011 forecast (Resource Plan Update) with the forecasts originally filed in the 2010 Resource Plan.

Figure 1 indicates that the energy forecast is lower than the original Resource Plan forecast. This is mainly due to a reduction in historical volumes caused by the recession and slower recovery and subsequent expected growth in all economic indicators than was previously expected. Other factors not included in the original 2010 IRP forecast are the termination of almost all firm wholesale contracts by the end of 2012 and the partial or full shutdown of several large industrial customers.

**Figure 1**
**Net Energy Requirements (MWh) Median (50th Percentile)**
**Forecast Comparison of Fall 2011 and 2010 IRP Forecasts**

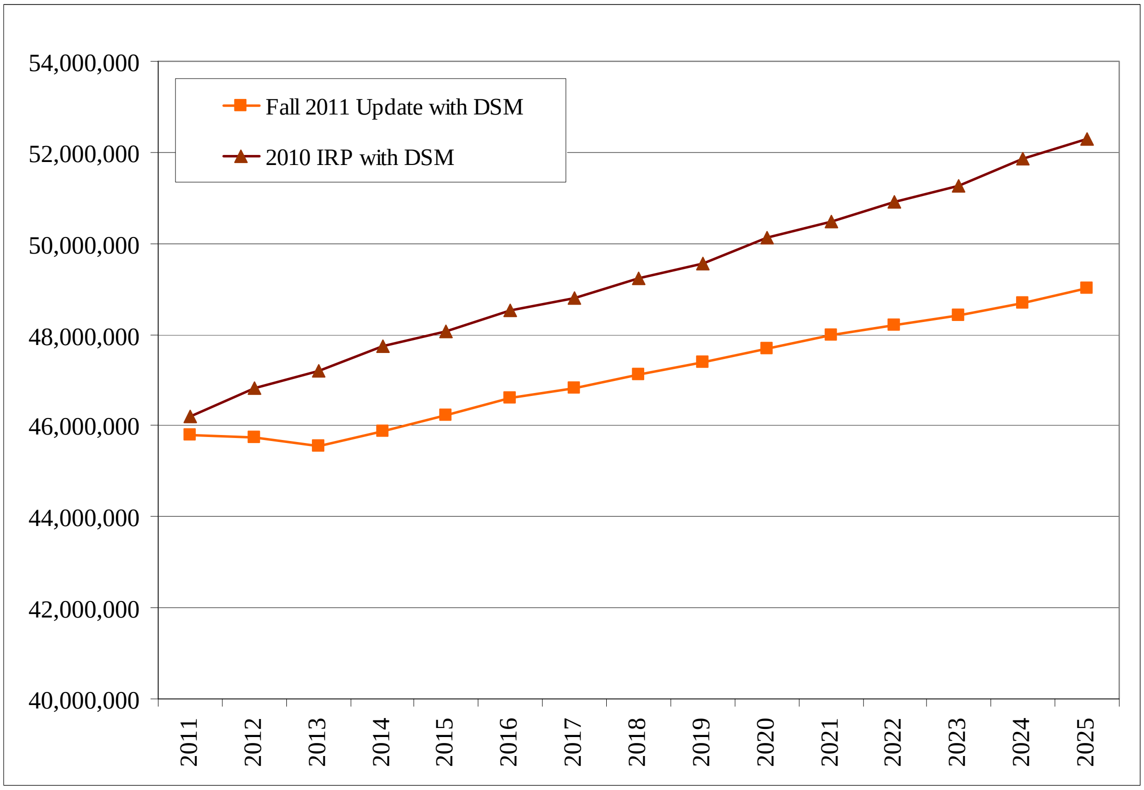
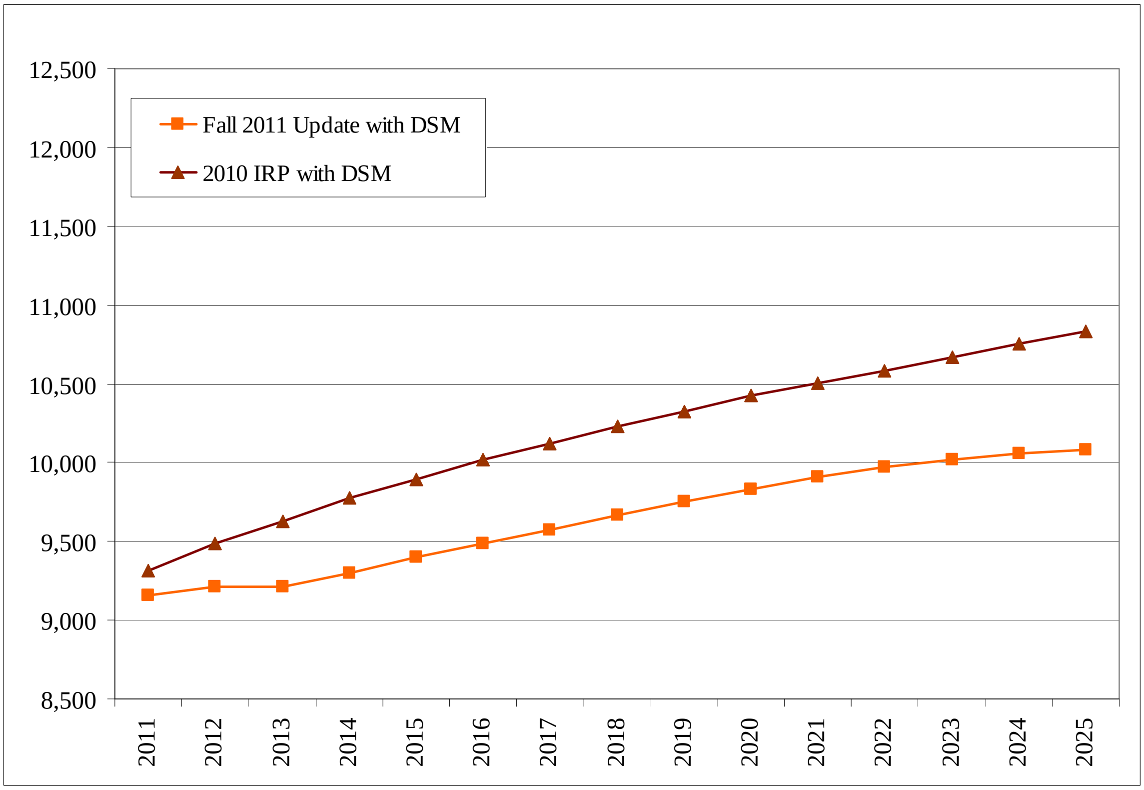



Figure 2 shows a comparison of the 50 percent peak demand forecast originally filed in the 2010 IRP with those developed in the Fall of 2011 (Resource Plan Update). Similar to the energy forecasts, the demand forecasts developed in the Fall of 2011 are lower than the original 2010 IRP forecast due to the economic recession and slow recovery, the termination of firm wholesale contracts and the partial or full shutdown of several large industrial customers.

**Figure 2**
**Base Peak Demand (MW) 50th Percentile Forecast**
**Comparison of Fall 2011 and 2010 IRP Forecasts**



## Forecast Content

The following tables are provided for compliance with 7849.0270 subp. 2. Please note that not all the customer categories listed in part B of the statute are tracked by the Company.

**NSP - Total Company**
**Historic and Forecasted Number of Customers**

| | Total Residential | Small C&I | Large C&I | Total C&I | Street Lighting | Public Authority | Interdept. | Total Other | Total Retail | Total Wholesale | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 1,379,851 | 175,484 | 753 | 176,237 | 3,784 | 2,810 | | 6,594 | 1,562,682 | 17 | 1,562,699 |
| 2004 | 1,404,993 | 179,326 | 769 | 180,095 | 4,299 | 2,813 | | 7,112 | 1,592,200 | 20 | 1,592,220 |
| 2005 | 1,389,605 | 176,358 | 616 | 176,974 | 4,290 | 2,716 | | 7,006 | 1,573,585 | 21 | 1,573,606 |
| 2006 | 1,413,729 | 180,050 | 599 | 180,649 | 4,430 | 2,709 | 37 | 7,176 | 1,601,554 | 24 | 1,601,578 |
| 2007 | 1,426,755 | 182,606 | 635 | 183,241 | 4,518 | 2,698 | 45 | 7,261 | 1,617,257 | 23 | 1,617,280 |
| 2008 | 1,437,869 | 184,756 | 619 | 185,375 | 4,533 | 2,688 | 55 | 7,276 | 1,630,520 | 22 | 1,630,542 |
| 2009 | 1,441,861 | 186,271 | 578 | 186,849 | 4,596 | 2,622 | 52 | 7,270 | 1,635,980 | 19 | 1,635,999 |
| 2010 | 1,451,290 | 188,165 | 602 | 188,767 | 4,829 | 2,613 | 59 | 7,501 | 1,647,558 | 16 | 1,647,574 |
| 2011 | 1,456,782 | 189,077 | 603 | 189,680 | 5,018 | 2,608 | 44 | 7,670 | 1,654,132 | 13 | 1,654,145 |
| 2012 | 1,467,943 | 190,500 | 600 | 191,100 | 5,050 | 2,596 | 59 | 7,705 | 1,666,748 | 12 | 1,666,760 |
| 2013 | 1,480,108 | 192,166 | 607 | 192,773 | 5,153 | 2,585 | 59 | 7,797 | 1,680,678 | 2 | 1,680,680 |
| 2014 | 1,492,678 | 193,877 | 613 | 194,490 | 5,258 | 2,574 | 59 | 7,891 | 1,695,059 | 1 | 1,695,060 |
| 2015 | 1,505,936 | 195,631 | 617 | 196,248 | 5,361 | 2,564 | 59 | 7,984 | 1,710,168 | 1 | 1,710,169 |
| 2016 | 1,519,185 | 197,352 | 619 | 197,971 | 5,465 | 2,555 | 59 | 8,079 | 1,725,235 | 1 | 1,725,236 |
| 2017 | 1,533,038 | 199,133 | 622 | 199,755 | 5,565 | 2,546 | 59 | 8,170 | 1,740,963 | 1 | 1,740,964 |
| 2018 | 1,547,416 | 200,929 | 625 | 201,554 | 5,662 | 2,538 | 59 | 8,259 | 1,757,229 | 1 | 1,757,230 |
| 2019 | 1,561,636 | 202,714 | 626 | 203,340 | 5,752 | 2,530 | 59 | 8,341 | 1,773,317 | 1 | 1,773,318 |
| 2020 | 1,575,087 | 204,420 | 628 | 205,048 | 5,839 | 2,524 | 59 | 8,422 | 1,788,557 | 1 | 1,788,558 |
| 2021 | 1,588,476 | 206,124 | 631 | 206,755 | 5,924 | 2,517 | 59 | 8,500 | 1,803,731 | 1 | 1,803,732 |
| 2022 | 1,602,364 | 207,879 | 629 | 208,508 | 6,009 | 2,510 | 59 | 8,578 | 1,819,450 | 1 | 1,819,451 |
| 2023 | 1,616,193 | 209,637 | 625 | 210,262 | 6,091 | 2,504 | 59 | 8,654 | 1,835,109 | 1 | 1,835,110 |
| 2024 | 1,629,824 | 211,360 | 620 | 211,980 | 6,172 | 2,498 | 59 | 8,729 | 1,850,533 | 1 | 1,850,534 |
| 2025 | 1,643,251 | 213,064 | 615 | 213,679 | 6,253 | 2,492 | 59 | 8,804 | 1,865,734 | 1 | 1,865,735 |
| 2026 | 1,656,790 | 214,779 | 611 | 215,390 | 6,332 | 2,487 | 59 | 8,878 | 1,881,058 | 1 | 1,881,059 |
| 2027 | 1,670,458 | 216,513 | 608 | 217,121 | 6,408 | 2,482 | 59 | 8,949 | 1,896,528 | 1 | 1,896,529 |
| 2028 | 1,684,763 | 218,321 | 603 | 218,924 | 6,485 | 2,477 | 59 | 9,021 | 1,912,708 | 1 | 1,912,709 |

## NSP - Minnesota Only
## Historic and Forecasted Number of Customers

| | Total Residential | Small C&I | Large C&I | Total C&I | Street Lighting | Public Authority | Interdept. | Total Other | Total Retail | Total Wholesale | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 1,043,231 | 148,558 | 120,818 | 269,376 | 2,712 | 2,142 | 0 | 4,854 | 1,317,461 | 7 | 1,317,468 |
| 2004 | 1,062,137 | 151,411 | 123,488 | 274,899 | 3,188 | 2,140 | 0 | 5,328 | 1,342,364 | 10 | 1,342,374 |
| 2005 | 1,047,452 | 147,734 | 120,420 | 268,154 | 3,151 | 2,093 | 0 | 5,244 | 1,320,850 | 11 | 1,320,861 |
| 2006 | 1,065,337 | 150,531 | 122,867 | 273,398 | 3,276 | 2,058 | 4 | 5,334 | 1,344,069 | 14 | 1,344,083 |
| 2007 | 1,074,894 | 152,441 | 124,648 | 277,089 | 3,346 | 2,049 | 8 | 5,395 | 1,357,378 | 13 | 1,357,391 |
| 2008 | 1,082,161 | 125,393 | 483 | 125,876 | 3,346 | 2,030 | 8 | 5,384 | 1,213,421 | 12 | 1,213,433 |
| 2009 | 1,084,245 | 126,373 | 446 | 126,819 | 3,381 | 2,015 | 8 | 5,404 | 1,216,468 | 9 | 1,216,477 |
| 2010 | 1,091,363 | 127,783 | 465 | 128,248 | 3,616 | 2,013 | 9 | 5,638 | 1,225,249 | 6 | 1,225,255 |
| 2011 | 1,095,812 | 128,447 | 462 | 128,909 | 3,768 | 2,018 | 6 | 5,792 | 1,230,513 | 3 | 1,230,516 |
| 2012 | 1,103,880 | 129,180 | 461 | 129,641 | 3,786 | 1,999 | 9 | 5,794 | 1,239,315 | 3 | 1,239,318 |
| 2013 | 1,112,923 | 130,224 | 468 | 130,692 | 3,874 | 1,990 | 9 | 5,873 | 1,249,488 | 2 | 1,249,490 |
| 2014 | 1,122,704 | 131,361 | 474 | 131,835 | 3,962 | 1,981 | 9 | 5,952 | 1,260,491 | 1 | 1,260,492 |
| 2015 | 1,132,783 | 132,536 | 478 | 133,014 | 4,047 | 1,973 | 9 | 6,029 | 1,271,826 | 1 | 1,271,827 |
| 2016 | 1,142,750 | 133,702 | 480 | 134,182 | 4,134 | 1,966 | 9 | 6,109 | 1,283,041 | 1 | 1,283,042 |
| 2017 | 1,153,518 | 134,965 | 483 | 135,448 | 4,218 | 1,959 | 9 | 6,186 | 1,295,152 | 1 | 1,295,153 |
| 2018 | 1,164,616 | 136,269 | 486 | 136,755 | 4,300 | 1,953 | 9 | 6,262 | 1,307,633 | 1 | 1,307,634 |
| 2019 | 1,175,807 | 137,587 | 487 | 138,074 | 4,377 | 1,947 | 9 | 6,333 | 1,320,214 | 1 | 1,320,215 |
| 2020 | 1,186,399 | 138,835 | 489 | 139,324 | 4,451 | 1,942 | 9 | 6,402 | 1,332,125 | 1 | 1,332,126 |
| 2021 | 1,197,020 | 140,088 | 492 | 140,580 | 4,523 | 1,937 | 9 | 6,469 | 1,344,069 | 1 | 1,344,070 |
| 2022 | 1,208,275 | 141,417 | 490 | 141,907 | 4,595 | 1,932 | 9 | 6,536 | 1,356,718 | 1 | 1,356,719 |
| 2023 | 1,219,559 | 142,751 | 486 | 143,237 | 4,665 | 1,928 | 9 | 6,602 | 1,369,398 | 1 | 1,369,399 |
| 2024 | 1,230,746 | 144,074 | 481 | 144,555 | 4,735 | 1,924 | 9 | 6,668 | 1,381,969 | 1 | 1,381,970 |
| 2025 | 1,241,796 | 145,382 | 476 | 145,858 | 4,805 | 1,920 | 9 | 6,734 | 1,394,388 | 1 | 1,394,389 |
| 2026 | 1,253,023 | 146,711 | 472 | 147,183 | 4,873 | 1,917 | 9 | 6,799 | 1,407,005 | 1 | 1,407,006 |
| 2027 | 1,264,420 | 148,061 | 469 | 148,530 | 4,940 | 1,914 | 9 | 6,863 | 1,419,813 | 1 | 1,419,814 |
| 2028 | 1,276,490 | 149,491 | 464 | 149,955 | 5,006 | 1,911 | 9 | 6,926 | 1,433,371 | 1 | 1,433,372 |

### NSP - Total Company
### Annual Energy Consumption

| | Residential w/o Sp Heat | Residential w/ Sp Heat | Total Residential | Small C&I | Large C&I | Total C&I | Street Lighting | Public Authority | Interdept | Total Other | Total Retail | Wholesale | Total Mwh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 10,680,301 | 981,766 | 11,662,067 | 16,579,354 | 11,443,959 | 28,023,313 | 177,054 | 127,745 | 16,525 | 321,323 | 40,006,704 | 809,894 | 40,816,598 |
| 2004 | 10,459,500 | 942,528 | 11,402,028 | 16,644,896 | 11,708,988 | 28,353,884 | 188,087 | 116,072 | 18,481 | 322,640 | 40,078,552 | 963,618 | 41,042,169 |
| 2005 | 11,169,742 | 935,853 | 12,105,594 | 18,272,282 | 11,110,675 | 29,382,957 | 184,643 | 118,715 | 8,511 | 311,869 | 41,800,420 | 1,176,285 | 42,976,705 |
| 2006 | 11,236,540 | 910,638 | 12,147,178 | 18,276,180 | 11,354,870 | 29,631,050 | 192,808 | 116,475 | 8,661 | 317,944 | 42,096,172 | 1,526,496 | 43,622,668 |
| 2007 | 11,835,008 | 656,244 | 12,491,252 | 18,492,190 | 11,724,807 | 30,216,998 | 185,376 | 113,206 | 14,540 | 313,122 | 43,021,372 | 1,538,399 | 44,559,771 |
| 2008 | 11,363,669 | 673,452 | 12,037,121 | 18,464,532 | 11,772,762 | 30,237,294 | 185,966 | 103,132 | 9,174 | 298,273 | 42,572,688 | 1,504,301 | 44,076,989 |
| 2009 | 11,111,576 | 672,022 | 11,783,599 | 18,052,021 | 10,772,546 | 28,824,567 | 189,836 | 103,092 | 10,828 | 303,756 | 40,911,922 | 1,251,121 | 42,163,043 |
| 2010 | 11,702,687 | 672,459 | 12,375,146 | 18,169,958 | 11,339,000 | 29,508,958 | 190,654 | 99,054 | 12,395 | 302,103 | 42,186,207 | 844,573 | 43,030,779 |
| 2011 | 11,728,620 | 700,826 | 12,429,445 | 18,156,958 | 11,428,290 | 29,585,248 | 194,205 | 99,264 | 12,222 | 305,691 | 42,320,385 | 588,684 | 42,909,069 |
| 2012 | 11,595,715 | 679,991 | 12,275,706 | 18,093,409 | 11,407,270 | 29,500,678 | 194,665 | 102,204 | 11,456 | 308,325 | 42,084,709 | 438,011 | 42,522,720 |
| 2013 | 11,688,026 | 676,571 | 12,364,597 | 18,159,896 | 11,489,835 | 29,649,731 | 196,499 | 100,902 | 11,456 | 308,856 | 42,323,184 | 23,027 | 42,346,211 |
| 2014 | 11,792,091 | 680,936 | 12,473,026 | 18,255,700 | 11,609,352 | 29,865,052 | 198,329 | 99,730 | 11,456 | 309,514 | 42,647,592 | 3,416 | 42,651,008 |
| 2015 | 11,903,055 | 679,114 | 12,582,170 | 18,354,084 | 11,713,717 | 30,067,801 | 200,197 | 98,537 | 11,456 | 310,190 | 42,960,161 | 3,423 | 42,963,584 |
| 2016 | 12,007,172 | 684,338 | 12,691,509 | 18,476,187 | 11,835,481 | 30,311,668 | 202,142 | 97,506 | 11,456 | 311,103 | 43,314,281 | 3,429 | 43,317,710 |
| 2017 | 12,090,641 | 682,691 | 12,773,332 | 18,504,030 | 11,917,316 | 30,421,346 | 204,031 | 96,571 | 11,456 | 312,057 | 43,506,736 | 3,436 | 43,510,172 |
| 2018 | 12,171,750 | 685,670 | 12,857,420 | 18,575,427 | 12,034,481 | 30,609,908 | 205,837 | 95,744 | 11,456 | 313,036 | 43,780,364 | 3,443 | 43,783,807 |
| 2019 | 12,248,884 | 686,028 | 12,934,911 | 18,629,694 | 12,156,273 | 30,785,967 | 207,574 | 94,871 | 11,456 | 313,902 | 44,034,780 | 3,450 | 44,038,230 |
| 2020 | 12,343,797 | 688,179 | 13,031,976 | 18,685,824 | 12,280,651 | 30,966,475 | 209,239 | 94,139 | 11,456 | 314,833 | 44,313,284 | 3,457 | 44,316,741 |
| 2021 | 12,445,986 | 687,541 | 13,133,527 | 18,732,696 | 12,408,207 | 31,140,904 | 210,879 | 93,437 | 11,456 | 315,772 | 44,590,203 | 3,464 | 44,593,667 |
| 2022 | 12,537,488 | 688,509 | 13,225,997 | 18,751,591 | 12,491,459 | 31,243,049 | 212,537 | 92,825 | 11,456 | 316,818 | 44,785,865 | 3,471 | 44,789,336 |
| 2023 | 12,634,174 | 688,361 | 13,322,534 | 18,770,347 | 12,584,376 | 31,354,723 | 214,136 | 92,152 | 11,456 | 317,744 | 44,995,001 | 3,478 | 44,998,478 |
| 2024 | 12,768,189 | 690,379 | 13,458,568 | 18,797,663 | 12,676,763 | 31,474,425 | 215,721 | 91,604 | 11,456 | 318,780 | 45,251,774 | 3,485 | 45,255,258 |
| 2025 | 12,943,971 | 691,063 | 13,635,034 | 18,818,298 | 12,767,942 | 31,586,240 | 217,300 | 91,072 | 11,456 | 319,828 | 45,541,102 | 3,492 | 45,544,593 |
| 2026 | 13,106,822 | 693,331 | 13,800,153 | 18,869,032 | 12,867,701 | 31,736,733 | 218,888 | 90,618 | 11,456 | 320,962 | 45,857,847 | 3,499 | 45,861,346 |
| 2027 | 13,263,204 | 694,751 | 13,957,954 | 18,906,117 | 12,978,043 | 31,884,160 | 220,461 | 90,090 | 11,456 | 322,007 | 46,164,122 | 3,506 | 46,167,627 |
| 2028 | 13,439,542 | 698,416 | 14,137,957 | 18,944,011 | 13,082,150 | 32,026,160 | 222,036 | 89,677 | 11,456 | 323,168 | 46,487,286 | 3,513 | 46,490,799 |

**NSP - Minnesota Only**
**Annual Energy Consumption**

| | Residential w/o Sp Heat | Residential w/ Sp Heat | Total Residential | Small C&I | Large C&I | Total C&I | Street Lighting | Public Authority | Interdept | Total Other | Total Retail |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 8,097,619 | 384,952 | 8,482,571 | 12,300,171 | 9,387,479 | 21,687,650 | 129,473 | 104,419 | 13,867 | 247,759 | 30,417,981 |
| 2004 | 7,916,320 | 373,041 | 8,289,361 | 12,375,215 | 9,489,401 | 21,864,616 | 139,813 | 93,102 | 16,311 | 249,226 | 30,403,203 |
| 2005 | 8,473,184 | 368,762 | 8,841,947 | 13,640,412 | 8,993,804 | 22,634,216 | 135,989 | 94,761 | 6,133 | 236,883 | 31,713,046 |
| 2006 | 8,525,645 | 350,900 | 8,876,545 | 13,677,161 | 9,129,744 | 22,806,904 | 143,664 | 92,112 | 7,310 | 243,086 | 31,926,536 |
| 2007 | 8,747,807 | 375,278 | 9,123,085 | 13,722,963 | 9,395,486 | 23,118,449 | 135,836 | 89,390 | 12,013 | 237,239 | 32,478,773 |
| 2008 | 8,314,634 | 382,010 | 8,696,644 | 13,683,725 | 9,449,345 | 23,133,070 | 136,071 | 80,504 | 7,005 | 223,580 | 32,053,294 |
| 2009 | 8,104,166 | 375,107 | 8,479,273 | 13,400,674 | 8,551,188 | 21,951,862 | 137,899 | 80,183 | 9,072 | 227,154 | 30,658,289 |
| 2010 | 8,570,740 | 377,036 | 8,947,776 | 13,434,890 | 9,053,962 | 22,488,852 | 140,268 | 75,397 | 10,006 | 225,671 | 31,662,300 |
| 2011 | 8,579,451 | 389,580 | 8,969,031 | 13,393,931 | 9,064,449 | 22,458,380 | 143,220 | 74,454 | 8,049 | 225,723 | 31,653,133 |
| 2012 | 8,438,365 | 381,432 | 8,819,797 | 13,353,049 | 9,009,704 | 22,362,753 | 142,433 | 78,645 | 9,014 | 230,092 | 31,412,643 |
| 2013 | 8,496,121 | 377,924 | 8,874,044 | 13,384,489 | 9,060,118 | 22,444,606 | 143,534 | 77,488 | 9,014 | 230,037 | 31,548,687 |
| 2014 | 8,553,602 | 378,377 | 8,931,980 | 13,429,139 | 9,140,546 | 22,569,685 | 144,628 | 76,461 | 9,014 | 230,104 | 31,731,768 |
| 2015 | 8,625,492 | 375,968 | 9,001,460 | 13,471,618 | 9,204,327 | 22,675,945 | 145,744 | 75,411 | 9,014 | 230,170 | 31,907,574 |
| 2016 | 8,683,183 | 377,366 | 9,060,549 | 13,529,618 | 9,282,690 | 22,812,308 | 146,896 | 74,520 | 9,014 | 230,430 | 32,103,287 |
| 2017 | 8,736,774 | 375,041 | 9,111,815 | 13,519,519 | 9,327,016 | 22,846,535 | 148,088 | 73,677 | 9,014 | 230,780 | 32,189,130 |
| 2018 | 8,784,789 | 375,318 | 9,160,106 | 13,544,151 | 9,404,727 | 22,948,878 | 149,276 | 72,941 | 9,014 | 231,232 | 32,340,216 |
| 2019 | 8,829,895 | 374,348 | 9,204,243 | 13,551,144 | 9,483,725 | 23,034,869 | 150,434 | 72,159 | 9,014 | 231,608 | 32,470,720 |
| 2020 | 8,890,026 | 374,436 | 9,264,462 | 13,563,435 | 9,563,552 | 23,126,988 | 151,531 | 71,516 | 9,014 | 232,061 | 32,623,511 |
| 2021 | 8,962,608 | 373,086 | 9,335,694 | 13,578,481 | 9,650,576 | 23,229,057 | 152,617 | 70,903 | 9,014 | 232,534 | 32,797,285 |
| 2022 | 9,021,050 | 372,476 | 9,393,525 | 13,564,822 | 9,704,894 | 23,269,716 | 153,715 | 70,378 | 9,014 | 233,108 | 32,896,349 |
| 2023 | 9,080,254 | 371,424 | 9,451,677 | 13,549,846 | 9,762,340 | 23,312,186 | 154,829 | 69,792 | 9,014 | 233,636 | 32,997,499 |
| 2024 | 9,168,702 | 371,620 | 9,540,322 | 13,540,868 | 9,822,058 | 23,362,926 | 155,954 | 69,329 | 9,014 | 234,298 | 33,137,546 |
| 2025 | 9,300,980 | 371,892 | 9,672,872 | 13,527,846 | 9,879,476 | 23,407,322 | 157,101 | 68,883 | 9,014 | 234,998 | 33,315,192 |
| 2026 | 9,422,786 | 372,816 | 9,795,602 | 13,544,004 | 9,945,598 | 23,489,602 | 158,266 | 68,512 | 9,014 | 235,792 | 33,520,997 |
| 2027 | 9,541,651 | 373,428 | 9,915,080 | 13,544,557 | 10,017,040 | 23,561,597 | 159,428 | 68,069 | 9,014 | 236,511 | 33,713,188 |
| 2028 | 9,672,794 | 375,298 | 10,048,091 | 13,544,203 | 10,083,942 | 23,628,145 | 160,598 | 67,738 | 9,014 | 237,350 | 33,913,586 |

**NSP - Total Company**
**Historic and Forecasted Peak Demand**

| | Residential | Commercial | Industrial | Other | Total Demand |
|---|---|---|---|---|---|
| 2003 | 3,074 | 3,113 | 1,933 | 161 | 8,281 |
| 2004 | 3,055 | 3,164 | 2,173 | 204 | 8,596 |
| 2005 | 3,222 | 3,174 | 1,884 | 221 | 8,501 |
| 2006 | 3,274 | 3,394 | 2,059 | 299 | 9,026 |
| 2007 | 2,836 | 3,525 | 2,182 | 260 | 8,803 |
| 2008 | 2,776 | 3,455 | 2,143 | 250 | 8,624 |
| 2009 | 2,860 | 3,415 | 2,051 | 221 | 8,546 |
| 2010 | 3,055 | 3,648 | 2,191 | 236 | 9,131 |
| 2011 | 3,749 | 3,656 | 2,223 | 164 | 9,792 |
| 2012 | 3,527 | 3,440 | 2,092 | 154 | 9,213 |
| 2013 | 3,527 | 3,440 | 2,092 | 154 | 9,213 |
| 2014 | 3,561 | 3,473 | 2,112 | 155 | 9,301 |
| 2015 | 3,597 | 3,509 | 2,134 | 157 | 9,397 |
| 2016 | 3,633 | 3,543 | 2,154 | 159 | 9,489 |
| 2017 | 3,665 | 3,575 | 2,174 | 160 | 9,573 |
| 2018 | 3,700 | 3,608 | 2,194 | 162 | 9,664 |
| 2019 | 3,733 | 3,641 | 2,214 | 163 | 9,750 |
| 2020 | 3,763 | 3,670 | 2,232 | 164 | 9,829 |
| 2021 | 3,793 | 3,699 | 2,249 | 166 | 9,907 |
| 2022 | 3,816 | 3,722 | 2,263 | 167 | 9,969 |
| 2023 | 3,835 | 3,740 | 2,274 | 167 | 10,017 |
| 2024 | 3,849 | 3,754 | 2,283 | 168 | 10,055 |
| 2025 | 3,858 | 3,763 | 2,288 | 168 | 10,078 |
| 2026 | 3,866 | 3,771 | 2,293 | 169 | 10,099 |
| 2027 | 3,880 | 3,784 | 2,301 | 169 | 10,134 |
| 2028 | 3,892 | 3,796 | 2,308 | 170 | 10,166 |

**NSP - Total System**
**Monthly Load Factors**

| | Native Energy Requirements (MWh) | Base Peak Demand (MW) | Days | Load Factor |
|---|---|---|---|---|
| Jan-03 | 3,803,608 | 6,371 | 31 | 80.2% |
| Feb-03 | 3,384,792 | 6,236 | 28 | 80.8% |
| Mar-03 | 3,527,760 | 5,954 | 31 | 79.6% |
| Apr-03 | 3,287,588 | 5,755 | 30 | 79.3% |
| May-03 | 3,310,402 | 5,892 | 31 | 75.5% |
| Jun-03 | 3,649,429 | 7,760 | 30 | 65.3% |
| Jul-03 | 4,218,642 | 8,066 | 31 | 70.3% |
| Aug-03 | 4,354,499 | 8,868 | 31 | 66.0% |
| Sep-03 | 3,561,053 | 7,819 | 30 | 63.3% |
| Oct-03 | 3,486,682 | 6,128 | 31 | 76.5% |
| Nov-03 | 3,425,474 | 6,136 | 30 | 77.5% |
| Dec-03 | 3,723,471 | 6,497 | 31 | 77.0% |
| Jan-04 | 3,905,061 | 6,653 | 31 | 78.9% |
| Feb-04 | 3,487,426 | 6,320 | 29 | 79.3% |
| Mar-04 | 3,559,448 | 5,941 | 31 | 80.5% |
| Apr-04 | 3,259,891 | 5,749 | 30 | 78.8% |
| May-04 | 3,399,231 | 6,240 | 31 | 73.2% |
| Jun-04 | 3,661,488 | 8,106 | 30 | 62.7% |
| Jul-04 | 4,177,268 | 8,665 | 31 | 64.8% |
| Aug-04 | 3,864,519 | 7,920 | 31 | 65.6% |
| Sep-04 | 3,776,737 | 8,029 | 30 | 65.3% |
| Oct-04 | 3,546,840 | 5,937 | 31 | 80.3% |
| Nov-04 | 3,511,756 | 6,224 | 30 | 78.4% |
| Dec-04 | 3,905,782 | 6,873 | 31 | 76.4% |

| | Native Energy Requirements (MWh) | Base Peak Demand (MW) | Days | Load Factor |
|---|---|---|---|---|
| Jan-05 | 3,916,456 | 6,636 | 31 | 79.3% |
| Feb-05 | 3,398,237 | 6,222 | 28 | 81.3% |
| Mar-05 | 3,667,801 | 5,996 | 31 | 82.2% |
| Apr-05 | 3,342,840 | 6,017 | 30 | 77.2% |
| May-05 | 3,525,768 | 6,055 | 31 | 78.3% |
| Jun-05 | 4,163,552 | 9,072 | 30 | 63.7% |
| Jul-05 | 4,605,640 | 8,945 | 31 | 69.2% |
| Aug-05 | 4,350,713 | 9,104 | 31 | 64.2% |
| Sep-05 | 3,853,840 | 7,512 | 30 | 71.3% |
| Oct-05 | 3,649,397 | 7,253 | 31 | 67.6% |
| Nov-05 | 3,574,084 | 6,466 | 30 | 76.8% |
| Dec-05 | 3,959,815 | 6,833 | 31 | 77.9% |
| Jan-06 | 3,852,014 | 6,332 | 31 | 81.8% |
| Feb-06 | 3,580,961 | 6,451 | 28 | 82.6% |
| Mar-06 | 3,757,537 | 6,058 | 31 | 83.4% |
| Apr-06 | 3,423,351 | 5,753 | 30 | 82.6% |
| May-06 | 3,778,659 | 7,273 | 31 | 69.8% |
| Jun-06 | 4,119,203 | 8,203 | 30 | 69.7% |
| Jul-06 | 4,895,295 | 9,859 | 31 | 66.7% |
| Aug-06 | 4,439,661 | 8,007 | 31 | 74.5% |
| Sep-06 | 3,629,557 | 7,132 | 30 | 70.7% |
| Oct-06 | 3,717,020 | 6,439 | 31 | 77.6% |
| Nov-06 | 3,647,831 | 6,599 | 30 | 76.8% |
| Dec-06 | 3,940,232 | 6,887 | 31 | 76.9% |

**NSP - Total System**
**Monthly Load Factors - continued**

| | Native Energy Requirements (MWh) | Base Peak Demand (MW) | Days | Load Factor |
|---|---|---|---|---|
| Jan-07 | 4,036,501 | 6,597 | 31 | 82.2% |
| Feb-07 | 3,748,020 | 6,740 | 28 | 82.8% |
| Mar-07 | 3,752,072 | 6,297 | 31 | 80.1% |
| Apr-07 | 3,528,276 | 5,985 | 30 | 81.9% |
| May-07 | 3,793,551 | 7,273 | 31 | 70.1% |
| Jun-07 | 4,261,258 | 9,210 | 30 | 64.3% |
| Jul-07 | 4,703,782 | 9,473 | 31 | 66.7% |
| Aug-07 | 4,546,156 | 9,051 | 31 | 67.5% |
| Sep-07 | 3,917,770 | 8,919 | 30 | 61.0% |
| Oct-07 | 3,823,393 | 6,710 | 31 | 76.6% |
| Nov-07 | 3,715,683 | 6,798 | 30 | 75.9% |
| Dec-07 | 4,124,795 | 6,968 | 31 | 79.6% |
| Jan-08 | 4,208,150 | 6,953 | 31 | 81.3% |
| Feb-08 | 3,900,939 | 6,900 | 29 | 81.2% |
| Mar-08 | 3,831,023 | 6,369 | 31 | 80.8% |
| Apr-08 | 3,580,870 | 5,917 | 30 | 84.1% |
| May-08 | 3,568,644 | 5,917 | 31 | 81.1% |
| Jun-08 | 3,860,078 | 8,001 | 30 | 67.0% |
| Jul-08 | 4,528,627 | 8,694 | 31 | 70.0% |
| Aug-08 | 4,416,662 | 8,432 | 31 | 70.4% |
| Sep-08 | 3,773,757 | 7,486 | 30 | 70.0% |
| Oct-08 | 3,694,984 | 6,048 | 31 | 82.1% |
| Nov-08 | 3,651,191 | 6,494 | 30 | 78.1% |
| Dec-08 | 4,130,010 | 7,226 | 31 | 76.8% |

| | Native Energy Requirements (MWh) | Base Peak Demand (MW) | Days | Load Factor |
|---|---|---|---|---|
| Jan-09 | 4,126,200 | 6,948 | 31 | 79.8% |
| Feb-09 | 3,574,053 | 6,597 | 28 | 80.6% |
| Mar-09 | 3,716,482 | 6,247 | 31 | 80.0% |
| Apr-09 | 3,410,854 | 5,757 | 30 | 82.3% |
| May-09 | 3,483,284 | 6,994 | 31 | 66.9% |
| Jun-09 | 3,847,934 | 8,609 | 30 | 62.1% |
| Jul-09 | 3,989,892 | 7,448 | 31 | 72.0% |
| Aug-09 | 4,089,921 | 8,248 | 31 | 66.6% |
| Sep-09 | 3,805,139 | 7,112 | 30 | 74.3% |
| Oct-09 | 3,630,942 | 5,882 | 31 | 83.0% |
| Nov-09 | 3,516,847 | 6,165 | 30 | 79.2% |
| Dec-09 | 4,032,800 | 6,971 | 31 | 77.8% |
| Jan-10 | 4,042,809 | 6,722 | 31 | 80.8% |
| Feb-10 | 3,544,970 | 6,414 | 28 | 82.2% |
| Mar-10 | 3,657,755 | 5,895 | 31 | 83.4% |
| Apr-10 | 3,390,415 | 5,844 | 30 | 80.6% |
| May-10 | 3,715,888 | 8,474 | 31 | 58.9% |
| Jun-10 | 3,942,951 | 8,366 | 30 | 65.5% |
| Jul-10 | 4,601,317 | 8,889 | 31 | 69.6% |
| Aug-10 | 4,704,821 | 9,131 | 31 | 69.3% |
| Sep-10 | 3,544,953 | 6,888 | 30 | 71.5% |
| Oct-10 | 3,607,576 | 6,277 | 31 | 77.2% |
| Nov-10 | 3,609,855 | 6,631 | 30 | 75.6% |
| Dec-10 | 4,058,982 | 6,848 | 31 | 79.7% |

**NSP - Total System**
**Monthly Load Factors - continued**

| | Native Energy Requirements (MWh) | Base Peak Demand (MW) | Days | Load Factor |
|---|---|---|---|---|
| Jan-11 | 4,092,587 | 6,691 | 31 | 82.2% |
| Feb-11 | 3,605,163 | 6,601 | 28 | 81.3% |
| Mar-11 | 3,795,065 | 6,235 | 31 | 81.8% |
| Apr-11 | 3,440,475 | 5,768 | 30 | 82.8% |
| May-11 | 3,570,130 | 6,318 | 31 | 76.0% |
| Jun-11 | 3,903,340 | 9,143 | 30 | 59.3% |
| Jul-11 | 4,801,579 | 9,623 | 31 | 67.1% |
| Aug-11 | 4,409,791 | 8,324 | 31 | 71.2% |
| Sep-11 | 3,653,240 | 8,698 | 30 | 58.3% |
| Oct-11 | 3,628,914 | 6,434 | 31 | 75.8% |
| Nov-11 | 3,543,328 | 6,184 | 30 | 79.6% |
| Dec-11 | 3,842,875 | 6,492 | 31 | 79.6% |
| Jan-12 | 4,052,035 | 6,815 | 31 | 79.9% |
| Feb-12 | 3,639,603 | 6,631 | 29 | 78.9% |
| Mar-12 | 3,749,101 | 6,236 | 31 | 80.8% |
| Apr-12 | 3,363,098 | 5,990 | 30 | 78.0% |
| May-12 | 3,564,822 | 7,151 | 31 | 67.0% |
| Jun-12 | 3,954,004 | 8,617 | 30 | 63.7% |
| Jul-12 | 4,390,784 | 9,213 | 31 | 64.1% |
| Aug-12 | 4,243,846 | 8,819 | 31 | 64.7% |
| Sep-12 | 3,645,419 | 8,002 | 30 | 63.3% |
| Oct-12 | 3,570,928 | 6,123 | 31 | 78.4% |
| Nov-12 | 3,576,643 | 6,621 | 30 | 75.0% |
| Dec-12 | 3,999,510 | 7,030 | 31 | 76.5% |

| | Native Energy Requirements (MWh) | Base Peak Demand (MW) | Days | Load Factor |
|---|---|---|---|---|
| Jan-13 | 4,039,755 | 6,831 | 31 | 79.5% |
| Feb-13 | 3,561,731 | 6,644 | 28 | 79.8% |
| Mar-13 | 3,741,376 | 6,259 | 31 | 80.3% |
| Apr-13 | 3,363,655 | 6,004 | 30 | 77.8% |
| May-13 | 3,543,603 | 7,173 | 31 | 66.4% |
| Jun-13 | 3,947,542 | 8,607 | 30 | 63.7% |
| Jul-13 | 4,383,557 | 9,213 | 31 | 64.0% |
| Aug-13 | 4,232,039 | 8,826 | 31 | 64.5% |
| Sep-13 | 3,638,466 | 8,038 | 30 | 62.9% |
| Oct-13 | 3,562,795 | 6,100 | 31 | 78.5% |
| Nov-13 | 3,567,681 | 6,620 | 30 | 74.8% |
| Dec-13 | 3,976,617 | 7,028 | 31 | 76.1% |
| Jan-14 | 4,062,776 | 6,903 | 31 | 79.1% |
| Feb-14 | 3,584,471 | 6,719 | 28 | 79.4% |
| Mar-14 | 3,759,919 | 6,331 | 31 | 79.8% |
| Apr-14 | 3,382,098 | 6,074 | 30 | 77.3% |
| May-14 | 3,563,632 | 7,280 | 31 | 65.8% |
| Jun-14 | 3,977,084 | 8,699 | 30 | 63.5% |
| Jul-14 | 4,417,165 | 9,301 | 31 | 63.8% |
| Aug-14 | 4,266,228 | 8,912 | 31 | 64.3% |
| Sep-14 | 3,665,704 | 8,150 | 30 | 62.5% |
| Oct-14 | 3,589,886 | 6,146 | 31 | 78.5% |
| Nov-14 | 3,596,535 | 6,696 | 30 | 74.6% |
| Dec-14 | 4,023,264 | 7,104 | 31 | 76.1% |

**NSP - Total System**
**Monthly Load Factors - continued**

| | Native Energy Requirements (MWh) | Base Peak Demand (MW) | Days | Load Factor |
|---|---|---|---|---|
| Jan-15 | 4,091,359 | 6,984 | 31 | 78.7% |
| Feb-15 | 3,620,226 | 6,797 | 28 | 79.3% |
| Mar-15 | 3,789,098 | 6,408 | 31 | 79.5% |
| Apr-15 | 3,409,004 | 6,147 | 30 | 77.0% |
| May-15 | 3,605,094 | 7,390 | 31 | 65.6% |
| Jun-15 | 4,008,323 | 8,795 | 30 | 63.3% |
| Jul-15 | 4,446,029 | 9,397 | 31 | 63.6% |
| Aug-15 | 4,295,648 | 9,009 | 31 | 64.1% |
| Sep-15 | 3,693,962 | 8,271 | 30 | 62.0% |
| Oct-15 | 3,596,114 | 6,195 | 31 | 78.0% |
| Nov-15 | 3,624,434 | 6,770 | 30 | 74.4% |
| Dec-15 | 4,047,728 | 7,182 | 31 | 75.8% |
| Jan-16 | 4,111,271 | 7,063 | 31 | 78.2% |
| Feb-16 | 3,683,390 | 6,875 | 29 | 77.0% |
| Mar-16 | 3,817,774 | 6,482 | 31 | 79.2% |
| Apr-16 | 3,445,848 | 6,216 | 30 | 77.0% |
| May-16 | 3,640,229 | 7,498 | 31 | 65.3% |
| Jun-16 | 4,037,186 | 8,889 | 30 | 63.1% |
| Jul-16 | 4,484,270 | 9,489 | 31 | 63.5% |
| Aug-16 | 4,325,292 | 9,100 | 31 | 63.9% |
| Sep-16 | 3,710,768 | 8,389 | 30 | 61.4% |
| Oct-16 | 3,624,031 | 6,239 | 31 | 78.1% |
| Nov-16 | 3,654,745 | 6,839 | 30 | 74.2% |
| Dec-16 | 4,074,586 | 7,254 | 31 | 75.5% |

| | Native Energy Requirements (MWh) | Base Peak Demand (MW) | Days | Load Factor |
|---|---|---|---|---|
| Jan-17 | 4,136,663 | 7,133 | 31 | 77.9% |
| Feb-17 | 3,670,259 | 6,945 | 28 | 78.6% |
| Mar-17 | 3,846,336 | 6,550 | 31 | 78.9% |
| Apr-17 | 3,473,072 | 6,280 | 30 | 76.8% |
| May-17 | 3,639,426 | 7,600 | 31 | 64.4% |
| Jun-17 | 4,060,783 | 8,976 | 30 | 62.8% |
| Jul-17 | 4,494,865 | 9,573 | 31 | 63.1% |
| Aug-17 | 4,338,988 | 9,186 | 31 | 63.5% |
| Sep-17 | 3,730,340 | 8,501 | 30 | 60.9% |
| Oct-17 | 3,646,607 | 6,278 | 31 | 78.1% |
| Nov-17 | 3,687,535 | 6,904 | 30 | 74.2% |
| Dec-17 | 4,091,556 | 7,323 | 31 | 75.1% |
| Jan-18 | 4,169,944 | 7,203 | 31 | 77.8% |
| Feb-18 | 3,695,709 | 7,013 | 28 | 78.4% |
| Mar-18 | 3,871,230 | 6,615 | 31 | 78.7% |
| Apr-18 | 3,484,564 | 6,342 | 30 | 76.3% |
| May-18 | 3,659,443 | 7,710 | 31 | 63.8% |
| Jun-18 | 4,081,598 | 9,070 | 30 | 62.5% |
| Jul-18 | 4,525,777 | 9,664 | 31 | 62.9% |
| Aug-18 | 4,371,070 | 9,277 | 31 | 63.3% |
| Sep-18 | 3,748,774 | 8,620 | 30 | 60.4% |
| Oct-18 | 3,673,444 | 6,321 | 31 | 78.1% |
| Nov-18 | 3,704,300 | 6,972 | 30 | 73.8% |
| Dec-18 | 4,126,190 | 7,393 | 31 | 75.0% |

**NSP - Total System**
**Monthly Load Factors - continued**

| | Native Energy Requirements (MWh) | Base Peak Demand (MW) | Days | Load Factor |
|---|---|---|---|---|
| Jan-19 | 4,190,098 | 7,272 | 31 | 77.4% |
| Feb-19 | 3,720,336 | 7,081 | 28 | 78.2% |
| Mar-19 | 3,885,898 | 6,680 | 31 | 78.2% |
| Apr-19 | 3,506,288 | 6,403 | 30 | 76.1% |
| May-19 | 3,693,975 | 7,817 | 31 | 63.5% |
| Jun-19 | 4,101,460 | 9,161 | 30 | 62.2% |
| Jul-19 | 4,552,817 | 9,750 | 31 | 62.8% |
| Aug-19 | 4,391,672 | 9,363 | 31 | 63.0% |
| Sep-19 | 3,779,097 | 8,734 | 30 | 60.1% |
| Oct-19 | 3,686,352 | 6,357 | 31 | 77.9% |
| Nov-19 | 3,722,960 | 7,031 | 30 | 73.5% |
| Dec-19 | 4,156,904 | 7,457 | 31 | 74.9% |
| Jan-20 | 4,215,566 | 7,334 | 31 | 77.3% |
| Feb-20 | 3,700,760 | 7,143 | 29 | 74.4% |
| Mar-20 | 3,922,728 | 6,740 | 31 | 78.2% |
| Apr-20 | 3,541,235 | 6,458 | 30 | 76.2% |
| May-20 | 3,730,308 | 7,916 | 31 | 63.3% |
| Jun-20 | 4,133,720 | 9,243 | 30 | 62.1% |
| Jul-20 | 4,581,708 | 9,829 | 31 | 62.7% |
| Aug-20 | 4,417,375 | 9,444 | 31 | 62.9% |
| Sep-20 | 3,796,159 | 8,841 | 30 | 59.6% |
| Oct-20 | 3,706,343 | 6,392 | 31 | 77.9% |
| Nov-20 | 3,755,984 | 7,094 | 30 | 73.5% |
| Dec-20 | 4,186,749 | 7,523 | 31 | 74.8% |

| | Native Energy Requirements (MWh) | Base Peak Demand (MW) | Days | Load Factor |
|---|---|---|---|---|
| Jan-21 | 4,239,228 | 7,403 | 31 | 77.0% |
| Feb-21 | 3,775,871 | 7,210 | 28 | 77.9% |
| Mar-21 | 3,960,284 | 6,807 | 31 | 78.2% |
| Apr-21 | 3,562,935 | 6,520 | 30 | 75.9% |
| May-21 | 3,731,504 | 8,017 | 31 | 62.6% |
| Jun-21 | 4,162,885 | 9,326 | 30 | 62.0% |
| Jul-21 | 4,586,772 | 9,907 | 31 | 62.2% |
| Aug-21 | 4,433,298 | 9,524 | 31 | 62.6% |
| Sep-21 | 3,813,541 | 8,948 | 30 | 59.2% |
| Oct-21 | 3,728,608 | 6,429 | 31 | 78.0% |
| Nov-21 | 3,792,818 | 7,158 | 30 | 73.6% |
| Dec-21 | 4,198,014 | 7,589 | 31 | 74.4% |
| Jan-22 | 4,270,383 | 7,461 | 31 | 76.9% |
| Feb-22 | 3,797,887 | 7,265 | 28 | 77.8% |
| Mar-22 | 3,976,617 | 6,858 | 31 | 77.9% |
| Apr-22 | 3,573,554 | 6,567 | 30 | 75.6% |
| May-22 | 3,745,989 | 8,104 | 31 | 62.1% |
| Jun-22 | 4,172,170 | 9,395 | 30 | 61.7% |
| Jul-22 | 4,608,437 | 9,969 | 31 | 62.1% |
| Aug-22 | 4,459,728 | 9,588 | 31 | 62.5% |
| Sep-22 | 3,820,224 | 9,039 | 30 | 58.7% |
| Oct-22 | 3,747,325 | 6,445 | 31 | 78.2% |
| Nov-22 | 3,803,828 | 7,200 | 30 | 73.4% |
| Dec-22 | 4,221,415 | 7,634 | 31 | 74.3% |

**NSP - Total System**
**Monthly Load Factors - continued**

| | Native Energy Requirements (MWh) | Base Peak Demand (MW) | Days | Load Factor |
|---|---|---|---|---|
| Jan-23 | 4,287,010 | 7,504 | 31 | 76.8% |
| Feb-23 | 3,816,859 | 7,307 | 28 | 77.7% |
| Mar-23 | 3,979,634 | 6,897 | 31 | 77.6% |
| Apr-23 | 3,594,113 | 6,601 | 30 | 75.6% |
| May-23 | 3,776,008 | 8,179 | 31 | 62.0% |
| Jun-23 | 4,184,474 | 9,451 | 30 | 61.5% |
| Jul-23 | 4,636,796 | 10,017 | 31 | 62.2% |
| Aug-23 | 4,470,306 | 9,640 | 31 | 62.3% |
| Sep-23 | 3,848,540 | 9,120 | 30 | 58.6% |
| Oct-23 | 3,763,001 | 6,451 | 31 | 78.4% |
| Nov-23 | 3,813,151 | 7,232 | 30 | 73.2% |
| Dec-23 | 4,254,889 | 7,669 | 31 | 74.6% |
| Jan-24 | 4,310,170 | 7,533 | 31 | 76.9% |
| Feb-24 | 3,791,365 | 7,336 | 29 | 74.3% |
| Mar-24 | 4,016,999 | 6,926 | 31 | 78.0% |
| Apr-24 | 3,624,339 | 6,625 | 30 | 76.0% |
| May-24 | 3,807,720 | 8,245 | 31 | 62.1% |
| Jun-24 | 4,216,489 | 9,496 | 30 | 61.7% |
| Jul-24 | 4,661,460 | 10,055 | 31 | 62.3% |
| Aug-24 | 4,496,520 | 9,682 | 31 | 62.4% |
| Sep-24 | 3,871,910 | 9,191 | 30 | 58.5% |
| Oct-24 | 3,774,732 | 6,451 | 31 | 78.7% |
| Nov-24 | 3,844,243 | 7,259 | 30 | 73.6% |
| Dec-24 | 4,286,081 | 7,698 | 31 | 74.8% |

| | Native Energy Requirements (MWh) | Base Peak Demand (MW) | Days | Load Factor |
|---|---|---|---|---|
| Jan-25 | 4,331,325 | 7,559 | 31 | 77.0% |
| Feb-25 | 3,869,869 | 7,361 | 28 | 78.2% |
| Mar-25 | 4,061,613 | 6,949 | 31 | 78.6% |
| Apr-25 | 3,639,457 | 6,642 | 30 | 76.1% |
| May-25 | 3,808,705 | 8,302 | 31 | 61.7% |
| Jun-25 | 4,249,046 | 9,530 | 30 | 61.9% |
| Jul-25 | 4,662,341 | 10,078 | 31 | 62.2% |
| Aug-25 | 4,514,457 | 9,710 | 31 | 62.5% |
| Sep-25 | 3,885,746 | 9,249 | 30 | 58.4% |
| Oct-25 | 3,801,070 | 6,439 | 31 | 79.3% |
| Nov-25 | 3,890,776 | 7,275 | 30 | 74.3% |
| Dec-25 | 4,297,609 | 7,717 | 31 | 74.9% |
| Jan-26 | 4,372,019 | 7,578 | 31 | 77.5% |
| Feb-26 | 3,901,736 | 7,377 | 28 | 78.7% |
| Mar-26 | 4,084,771 | 6,965 | 31 | 78.8% |
| Apr-26 | 3,665,442 | 6,654 | 30 | 76.5% |
| May-26 | 3,835,699 | 8,352 | 31 | 61.7% |
| Jun-26 | 4,266,351 | 9,560 | 30 | 62.0% |
| Jul-26 | 4,695,641 | 10,099 | 31 | 62.5% |
| Aug-26 | 4,555,534 | 9,738 | 31 | 62.9% |
| Sep-26 | 3,898,959 | 9,308 | 30 | 58.2% |
| Oct-26 | 3,830,817 | 6,428 | 31 | 80.1% |
| Nov-26 | 3,916,777 | 7,294 | 30 | 74.6% |
| Dec-26 | 4,329,055 | 7,739 | 31 | 75.2% |

**NSP - Total System**
**Monthly Load Factors - continued**

| | Native Energy Requirements (MWh) | Base Peak Demand (MW) | Days | Load Factor |
|---|---|---|---|---|
| Jan-27 | 4,401,718 | 7,609 | 31 | 77.8% |
| Feb-27 | 3,930,032 | 7,407 | 28 | 79.0% |
| Mar-27 | 4,090,630 | 6,995 | 31 | 78.6% |
| Apr-27 | 3,699,421 | 6,680 | 30 | 76.9% |
| May-27 | 3,875,139 | 8,418 | 31 | 61.9% |
| Jun-27 | 4,284,579 | 9,605 | 30 | 62.0% |
| Jul-27 | 4,740,041 | 10,134 | 31 | 62.9% |
| Aug-27 | 4,567,485 | 9,779 | 31 | 62.8% |
| Sep-27 | 3,935,190 | 9,378 | 30 | 58.3% |
| Oct-27 | 3,859,509 | 6,428 | 31 | 80.7% |
| Nov-27 | 3,924,517 | 7,323 | 30 | 74.4% |
| Dec-27 | 4,375,479 | 7,771 | 31 | 75.7% |
| Jan-28 | 4,431,243 | 7,638 | 31 | 78.0% |
| Feb-28 | 3,907,140 | 7,435 | 29 | 75.5% |
| Mar-28 | 4,138,359 | 7,022 | 31 | 79.2% |
| Apr-28 | 3,734,279 | 6,702 | 30 | 77.4% |
| May-28 | 3,912,367 | 8,483 | 31 | 62.0% |
| Jun-28 | 4,326,538 | 9,647 | 30 | 62.3% |
| Jul-28 | 4,766,614 | 10,166 | 31 | 63.0% |
| Aug-28 | 4,599,692 | 9,818 | 31 | 63.0% |
| Sep-28 | 3,969,258 | 9,447 | 30 | 58.4% |
| Oct-28 | 3,869,489 | 6,425 | 31 | 81.0% |
| Nov-28 | 3,960,602 | 7,346 | 30 | 74.9% |
| Dec-28 | 4,416,349 | 7,797 | 31 | 76.1% |

## Appendix B
## Xcel Energy Demand Side Management Programs

Minn. Rules 7849.0240, subp. 2.B requires that an application for a Certificate of Need include an explanation of promotional activities that may have given rise to the demand for the facility. Xcel Energy does not have programs promoting the sale of electricity, but rather programs that promote the conservation of electricity.

Xcel Energy has proposed two new tariffs in its pending electric rate case to offer two services: a competitive service offering, which addresses retention and expansion for our largest customers; and a development offering which provides incentive for business customers to expand operations, make new investments in Minnesota, and create jobs. The first tariff, the Competitive Response (CR) Rider, is an existing program currently located in two separate riders. The second tariff, the Business Incentive and Sustainability (BIS) Rider is a new program. Approval of the CR and BIS Riders would provide tools to retain load and encourage efficient growth on our system to the benefit of all customers. While the Company does not anticipate significant activity on these Riders if they are approved, having the tools available will be useful to responding efficiently and effectively should the opportunity arise.

Minn. R. 7849.0290 requires that an application for a Certificate of Need include information regarding the applicant's conservation and load management programs (collectively, "Demand Side Management" or "DSM"). This information is presented below for Xcel Energy.

Minn. R. 7849.0290 requires that an application must include:

### *A. The name of the committee, department, or individual responsible for the applicant's energy conservation and efficiency programs, including load management;*

Lee Gabler, Director, Energy Efficiency Marketing is responsible for Xcel Energy's demand-side management (conservation and load management) programs.

***B. A list of the applicant's energy conservation and efficiency goals and objectives***;

Xcel Energy's[1] approved 2013-2015 Triennial Plan[2] represents a budget of over $260 million, energy savings of 1,307 GWh and demand savings of 315 MW over the three years.

***C. A description of the specific energy conservation and efficiency programs the applicant has considered, a list of those that have been implemented, and the reasons why the other programs have not been implemented;***

Xcel Energy is required under Minn. Stat. § 216B.241, Subd. 1a to spend at least 2% of its electric gross operating revenue ("GOR") on electric conservation programs and 0.5% of its gas GOR on gas conservation programs. Additionally, the Next Generation Energy Act of 2007 requires utilities, beginning in 2010, to have an annual energy savings goal equivalent to 1.5% of gross annual retail sales, unless modified by the Commissioner. The minimum energy savings goal is 1.0% of retail sales.

To comply with the minimum spending requirement, Xcel Energy offers an extensive portfolio of programs. In general, these programs can be categorized as direct or indirect. Further, the direct programs can be categorized as prescriptive or custom.

Direct programs result in quantifiable energy savings. The Lighting Efficiency program, for example, offers rebates for the installation of energy efficient lighting within our business customer segment. Prescriptive programs use technical assumptions based on stipulated or deemed technical assumptions that are assigned to measures in order to calculate gross energy and demand savings. The rebates and savings are predetermined based on the deemed technical assumptions. Custom programs use technical assumptions that are specific to the actual measure characteristics in order to calculate the energy and demand savings. The rebates and savings vary with the measure. Further, direct programs can be categorized as

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[1] Northern States Power Company, a Minnesota Corporation.
[2] Docket No. E,G002/CIP-12-447

conservation or load management programs. Load management programs are specifically designed to manage peak load.

The following table lists our program offerings over the last ten years. Please note that some of the programs have been discontinued, modified or incorporated into other programs.

| 1.1.1.1 **Business Segment** |
|---|
| ***Conservation*** |
| Commercial Efficiency |
| Heating Efficiency f.k.a. Boiler Efficiency |
| Commercial Real Estate |
| Fluid Systems Optimization f.k.a. Compressed Air Efficiency |
| Commercial Audit and Contract Management |
| Computer Efficiency |
| Cooling Efficiency |
| Custom Efficiency |
| Data Center Efficiency |
| Distributed Generation Incentive |
| Efficiency Controls |
| Energy Assets |
| Energy Design Assistance (EDA) |
| Energy Design Assistance - Business New Construction |
| Energy Efficient Buildings – Business New Construction |
| Energy Efficient Rebate |
| Energy Management Systems |
| Food Service Equipment |
| Furnace Efficiency |
| Government Conservation |
| Heat Recovery Rebate |
| Industrial Efficiency |
| Lighting Efficiency |

| |
|---|
| Market Transformation – Computer Efficiency |
| Market Transformation – Vending Efficiency |
| Motor Efficiency |
| Process Efficiency |
| Recommissioning |
| Refrigeration Efficiency |
| Roofing Efficiency |
| Segment Efficiency |
| Self-Direct |
| Turn Key Services |
| ***Load Management*** |
| Electric Rates Savings f.k.a Peak Controlled Rates |
| Business Saver's Switch |
| ***Indirect Impact*** |
| Business Education |
| Energy Advisory Service |
| Energy Analysis |
| Energy Financing |
| Small Business Lamp Recycling |
| School Financing |
| **1.1.1.2 Residential Segment** |
| ***Conservation*** |
| Central AC Quality Installation |
| ENERGY STAR Homes |
| ENERGY STAR Rebates |
| Energy Efficiency Showerheads f.k.a High-Efficiency Showerheads |
| Energy Feedback Pilot |
| Heating System Rebates |
| Home Efficiency |
| Home Energy Squad f.k.a Residential Quick Fix Efficiency Service |
| Home Lighting f.k.a Home Lighting Direct Purchase |
| Home Performance with ENERGY STAR |

| |
|---|
| Insulation Rebate Program |
| Refrigerator Recycling |
| Residential Cooling |
| Premier Home |
| School Education Kits |
| Water Heater Rebates |
| ***Load Management*** |
| Residential Saver's Switch |
| ***Indirect Impact*** |
| Consumer Education |
| Energy Loans |
| Home Energy Audits |
| Residential Lamp Recycling |
| **1.1.1.3 Energy Efficiency Support Services** |
| **1.1.1.4 Low-Income Segment** |
| ***Conservation*** |
| Affordable Housing |
| Home Energy Savings Program f.k.a Home Electric Savings |
| Home Energy Savings Program f.k.a Low Income Weatherization |
| Low-Income Home Energy Squad f.k.a Residential Quick Fix – Low Income |
| Multi-Family Energy Savings Program |
| **Research, Evaluation & Pilots** |
| Annex 49 Pilot |

For more details on our current business, residential and low-income programs, see the Xcel Energy website at http://www.xcelenergy.com.

Xcel Energy's Product Development department continually analyzes potential measures and concepts to add to our program portfolio offering.  Measures and programs are analyzed and prioritized based on cost-effectiveness standards, availability potential within the marketplace and applicability potential within our customer base.

## *D. A description of the major accomplishments that have been made by the applicant with respect to energy conservation and efficiency*

The 2013-2015 CIP Triennial Plan continues Xcel Energy's long-standing commitment to DSM. Although DSM activities in many states around the country have ebbed and flowed, Minnesota and Xcel Energy as its largest utility have generally maintained a consistent approach to DSM. This long-standing commitment and dedication to excellence in running cost effective conservation and load management programs places the Company among the nation's top utilities in terms of energy and demand saved and most innovative programs.

Between 1990 and 2011, Xcel Energy has invested over $1 billion (nominal) resulting in 5,912 GWh of electric energy savings, 2,675 MW of electric demand savings and an estimated 10,992,937 MCF of natural gas savings. The following figures show our historical spending from 2000 through 2015 on CIP and energy savings achievements. Approved goals for 2013, 2014 and 2015 are provided for context.

**Figure 1**
**CIP Electric Expenditures, 2000-2015**

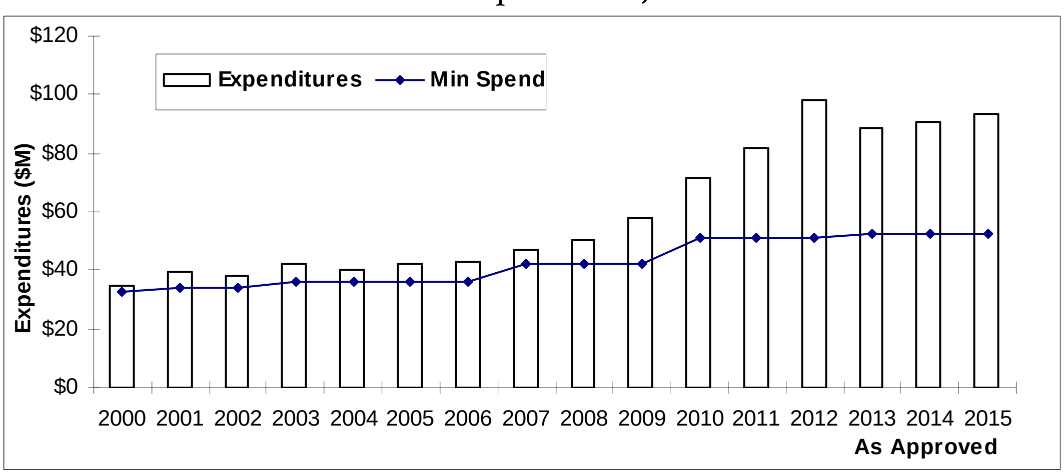


**Figure 2**
**CIP Gas Expenditures, 2000-2015**

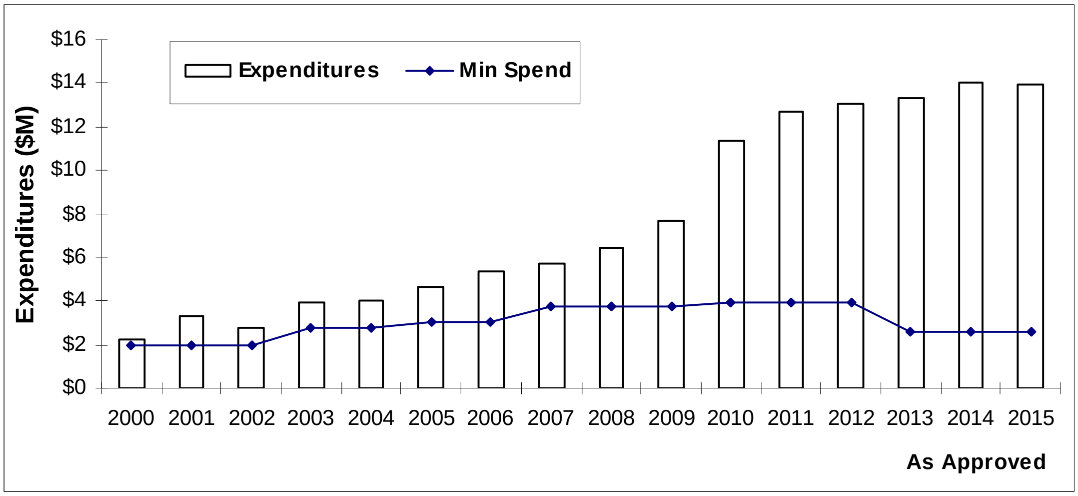



**Figure 3**
**CIP Electric Energy Savings, 2000-2015**

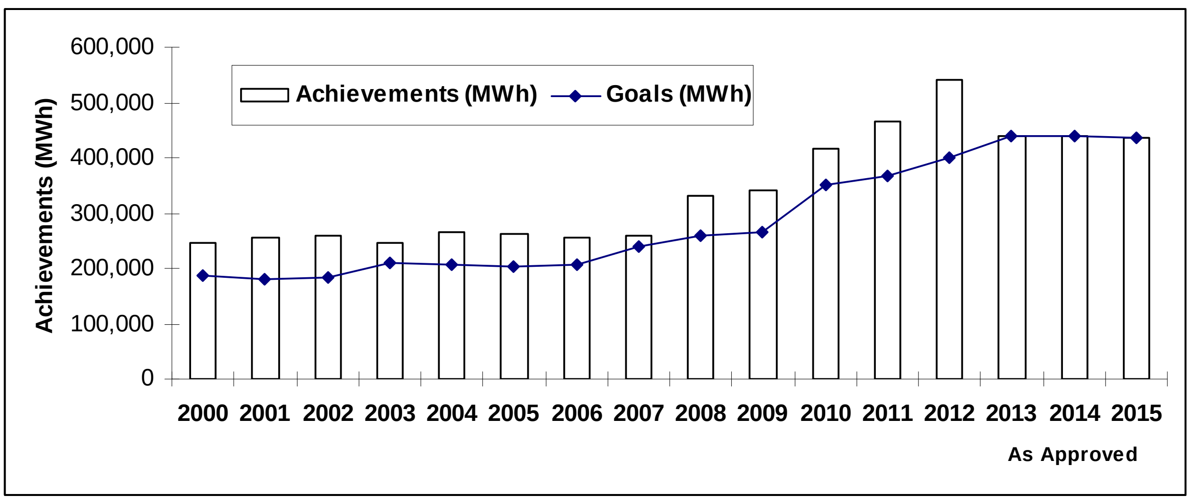


**Figure 4**
**CIP Electric Demand Savings, 2000-2015**

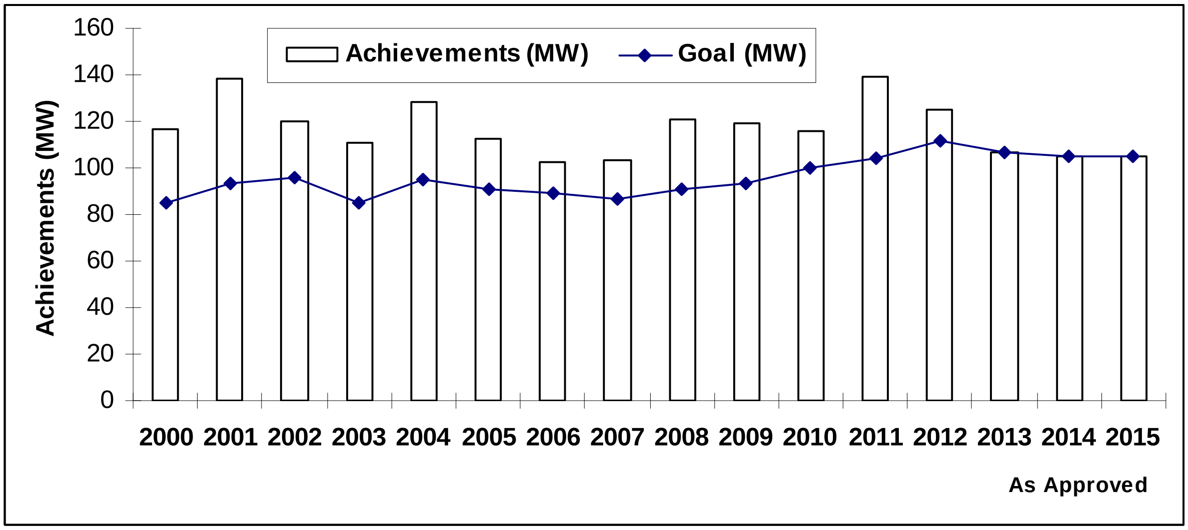
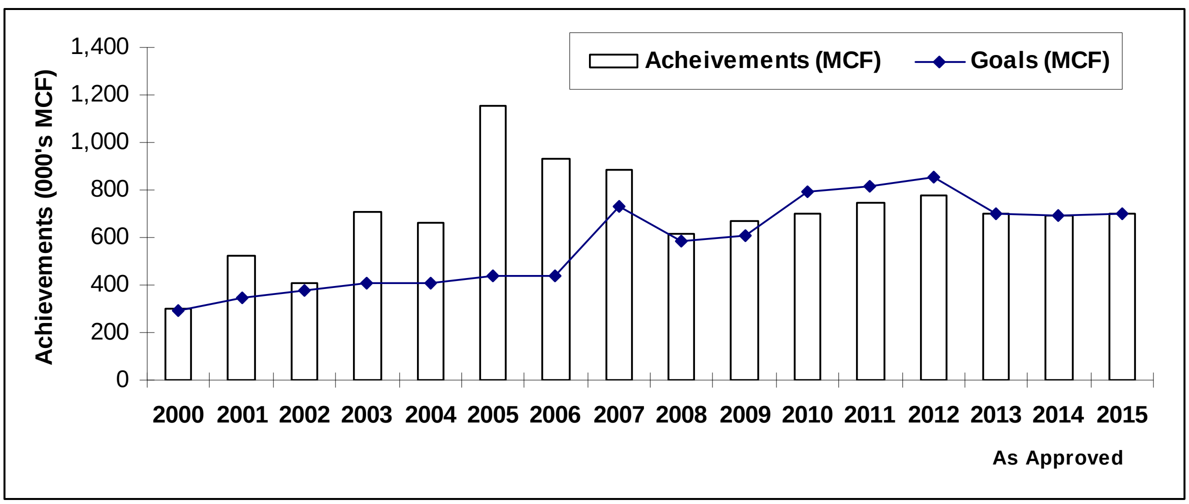



**Figure 5**
**CIP Natural Gas Savings, 2000-2015**



## *E. A description of the applicant's future plans through the forecast years with respect to energy conservation and efficiency*

On August 2, 2010, we filed our 2011-2025 Resource Plan[3]. Our intent with the plan was to continue our strategy of building a sustainable and dependable portfolio of DSM offerings that provides reliable savings at a reasonable cost. In light of that, we included the long term goal of 1.3% of retail energy sales for DSM. In the process of building the Resource Plan, we also modeled the 1.5% of retail sales scenario but found it to be a bit too aggressive for the later years of the plan. In addition, higher energy savings scenarios were investigated, as requested by interveners, with targeted savings goals higher than 1.5%, but we did not find sufficient program and cost information to enable us to develop a higher scenario. Moving to a level of savings beyond 1.5% may involve adoption of technologies that are not yet commercial.

On October 1, 2012, The Minnesota Department of Commerce: Division of Energy Resources approved our short term DSM goals as proposed in our 2013-15 Triennial Plan, which did included DSM goals of 1.5% of retail energy sales. More details regarding the approved Triennial Plan, including programs, savings and budgets, are included below.

The table below shows DSM energy and demand savings levels as proposed in our 2011-2025 Resource Plan.

[3] Docket No. E002/RP-10-825

**Current and Proposed Energy Efficiency Goals**
**At the Generator**

| Year | 2008-2022 Plan | 2008-2022 Plan | 1.3% Scenario | 1.3% Scenario | 1.3% Scenario | 1.5% Scenario | 1.5% Scenario | 1.5% Scenario |
|---|---|---|---|---|---|---|---|---|
| | Approved Demand Goal MW | Approved Energy Goal GWh | Demand Goal MW | Energy Goal GWh | Proposed Budget (millions) | Demand Goal MW | Energy Goal GWh | Proposed Budget (millions) |
| **2008** | 47 | 260 | | | | | | |
| **2009** | 49 | 264 | | | | | | |
| **2010** | 114 | 358 | | | | | | |
| **2011** | 123 | 374 | 63 | 367 | $81 | 63 | 367 | $81 |
| **2012** | 127 | 405 | 70 | 399 | $86 | 70 | 399 | $86 |
| **2013** | 133 | 421 | 83 | 390 | $106 | 93 | 450 | $124 |
| **2014** | 130 | 421 | 80 | 390 | $109 | 91 | 450 | $127 |
| **2015** | 128 | 421 | 79 | 390 | $112 | 90 | 450 | $129 |
| **2016** | 140 | 437 | 80 | 401 | $120 | 91 | 462 | $143 |
| **2017** | 145 | 437 | 81 | 401 | $125 | 92 | 462 | $152 |
| **2018** | 148 | 437 | 81 | 401 | $135 | 93 | 462 | $168 |
| **2019** | 154 | 453 | 84 | 412 | $149 | 97 | 475 | $190 |
| **2020** | 169 | 453 | 87 | 412 | $152 | 99 | 475 | $200 |
| **2021** | 169 | 453 | 90 | 412 | $155 | 102 | 475 | $203 |
| **2022** | 175 | 468 | 96 | 420 | $160 | 107 | 484 | $213 |
| **2023** | | | 101 | 420 | $167 | 113 | 484 | $218 |
| **2024** | | | 108 | 420 | $180 | 122 | 484 | $234 |
| **2025** | | | 119 | 431 | $190 | 133 | 497 | $242 |
| **2008-2022 Total** | **1,951** | **6,061** | | | | | | |
| **Avg Annual 2008-2022** | **130** | **404** | | | | | | |
| **2011-2025 Total** | | | **1,303** | **6,065** | | **1457** | **6879** | |
| **Avg Annual 2011-2025** | | | **87** | **404** | | **97** | **457** | |

* The goals for 2011 and 2012 are from our approved 2010-2012 CIP Triennial Plan.

### *F. A quantification of the manner by which these programs affect or help determine the forecast provided in response to part 7849.0270, subpart 2, a list of their total costs by program, and a discussion of their expected effects in reducing the need for new generation and transmission facilities*

Load forecasts are based on historical data. This historical data includes a trend of reducing annual peak demand and energy consumed caused by the historical achievement of DSM programs. Basing the forecasted annual peak demand for electricity and annual energy consumed on this historical data assumes this trend carries forward, or assumes that achievement of DSM occurs in the future at the same rate as it has in the past. This "trend" is known as embedded DSM and is roughly equal to the average annual DSM achievements obtained during the historical years. In this way, the unadjusted forecast does assume some level of future DSM achievement. To counteract this, an estimate of the embedded DSM impacts is added back into the load forecast. This effectively removes the impacts of embedded DSM to derive an estimate of peak and energy as if no DSM were going to be implemented in future years.

Once the embedded DSM impacts are removed, the DSM energy and demand goals proposed in the 2011 Resource Plan are then applied in the forecast used in resource planning analysis that determines future generation needs.

Below is a list of our approved 2013-2015 DSM programs including their individual budgets, energy and demand savings. There is one alternative filing, Trillion BTU, that is listed as filed but is still waiting on the final approval from the Department. Following the annual tables is a three year Triennial Plan roll-up.

## Executive Summary Table - Electric 2013

| 2013 | Electric Participants | Electric Budget | Customer kW | Generator kW | Generator kWh | Societal Test Ratio |
|---|---|---|---|---|---|---|
| **Business Segment** | | | | | | |
| Business New Construction | 53 | $6,145,119 | 6,412 | 6,287 | 26,464,770 | 1.32 |
| Commercial Efficiency | 10 | $1,049,963 | 700 | 443 | 4,259,068 | 1.41 |
| Computer Efficiency | 2,804 | $1,277,315 | 1,546 | 1,662 | 12,098,358 | 1.66 |
| Cooling Efficiency | 1,105 | $1,959,471 | 1,994 | 1,661 | 7,097,985 | 1.48 |
| Custom Efficiency | 121 | $3,014,398 | 3,608 | 1,739 | 16,816,821 | 1.63 |
| Data Center Efficiency | 13 | $753,467 | 557 | 398 | 4,831,078 | 3.20 |
| Efficiency Controls | 87 | $1,378,684 | 2,092 | 338 | 16,692,249 | 2.09 |
| Fluid Systems Optimization | 451 | $1,470,374 | 2,006 | 1,977 | 13,054,622 | 2.42 |
| Foodservice Equipment | 46 | $48,181 | 102 | 73 | 491,753 | 2.65 |
| Heating Efficiency | 0 | $0 | 0 | 0 | 0 | |
| Lighting Efficiency | 798 | $6,961,434 | 10,305 | 9,000 | 54,022,924 | 1.81 |
| Motor Efficiency | 877 | $4,316,494 | 7,217 | 6,057 | 36,021,638 | 2.14 |
| Process Efficiency | 74 | $6,023,911 | 10,608 | 7,752 | 65,971,934 | 2.63 |
| Recommissioning | 119 | $1,105,147 | 1,771 | 566 | 11,511,765 | 1.87 |
| Self-Direct | 10 | $1,870,868 | 3,220 | 2,172 | 9,917,591 | 1.46 |
| Turn Key Services | 353 | $1,375,116 | 1,905 | 602 | 6,931,471 | 1.71 |
| **Business Segment Energy Efficiency Total** | **6,921** | **$38,749,942** | **54,045** | **40,725** | **286,184,027** | **1.89** |
| Electric Rate Savings | 90 | $557,534 | 18,000 | 9,186 | 340,347 | 6.67 |
| Saver's Switch for Business | 1,151 | $1,970,791 | 12,620 | 3,256 | 21,090 | 1.57 |
| **Business Segment Load Management Total** | **1,241** | **$2,528,325** | **30,620** | **12,441** | **361,437** | **2.70** |
| Business Education | 14,000 | $247,498 | 0 | 0 | 0 | 0.00 |
| Small Business Lamp Recycling | 50,000 | $31,000 | 0 | 0 | 0 | 0.00 |
| **Business Segment Indirect Total** | **64,000** | **$278,498** | **0** | **0** | **0** | **0.00** |
| **Business Segment Total** | **72,162** | **$41,556,765** | **84,665** | **53,167** | **286,545,465** | **1.90** |
| | | | | | | |
| **Residential Segment** | | | | | | |
| Energy Efficient Showerheads | 1,050 | $14,488 | 175 | 0 | 360,781 | 8.51 |
| Energy Feedback | 150,000 | $1,110,027 | 896 | 668 | 8,570,819 | 0.96 |
| ENERGY STAR Homes | 860 | $195,622 | 315 | 108 | 916,126 | 1.68 |
| Heating System Rebates | 7,000 | $758,550 | 1,750 | 1,343 | 4,745,263 | 1.40 |
| Home Energy Squad | 5,500 | $1,188,089 | 3,461 | 574 | 2,820,471 | 1.24 |
| Home Lighting | 527,877 | $4,463,168 | 67,206 | 10,273 | 77,675,154 | 2.78 |
| Home Performance with ENERGY STAR® | 225 | $97,692 | 221 | 141 | 169,025 | 1.26 |
| Insulation Rebate | 288 | $86,211 | 453 | 231 | 331,717 | 1.37 |
| Refrigerator Recycling | 5,500 | $782,428 | 1,183 | 713 | 6,221,426 | 3.08 |
| Residential Cooling | 9,859 | $4,703,374 | 9,050 | 8,921 | 5,355,937 | 1.01 |
| School Education Kits | 20,000 | $616,858 | 2,189 | 181 | 2,231,297 | 1.48 |
| Water Heater Rebate | 0 | $0 | 0 | 0 | 0 | |
| **Residential Segment Energy Efficiency Total** | **728,159** | **$14,016,508** | **86,900** | **23,155** | **109,398,017** | **1.74** |
| **Residential Segment Load Management - Saver's Switch** | **20,000** | **$4,842,843** | **60,413** | **17,690** | **177,738** | **3.48** |
| Consumer Education | 433,854 | $775,640 | 0 | 0 | 0 | 0.00 |
| Home Energy Audit | 3,300 | $557,401 | 0 | 0 | 0 | 0.00 |
| Residential Lamp Recycling | 300,000 | $186,000 | 0 | 0 | 0 | 0.00 |
| **Residential Segment Indirect Total** | **737,154** | **$1,519,041** | **0** | **0** | **0** | **0.00** |
| **Residential Segment Total** | **1,485,313** | **$20,378,392** | **147,312** | **40,845** | **109,575,754** | **1.89** |
| | | | | | | |
| **Low-Income Segment** | | | | | | |
| Home Energy Savings Program | 2,100 | $1,354,160 | 584 | 188 | 938,843 | 0.65 |
| Low-Income Home Energy Squad | 1,650 | $386,163 | 1,365 | 196 | 1,105,499 | 1.56 |
| Multi-Family Energy Savings Program | 396 | $580,712 | 366 | 94 | 557,906 | 0.69 |
| **Low-Income Segment Total** | **4,146** | **$2,321,035** | **2,315** | **477** | **2,602,248** | **0.77** |
| | | | | | | |
| **Planning Segment** | | | | | | |
| Application Development and Maintenance | 0 | $1,101,600 | 0 | 0 | 0 | 0.00 |
| Advertising & Promotion | 0 | $2,520,000 | 0 | 0 | 0 | 0.00 |
| CIP Training | 0 | $125,000 | 0 | 0 | 0 | 0.00 |
| Regulatory Affairs | 0 | $408,142 | 0 | 0 | 0 | 0.00 |
| **Planning Segment Total** | **0** | **$4,154,742** | **0** | **0** | **0** | **0.00** |
| | | | | | | |
| **Research, Evaluations & Pilots Segment** | | | | | | |
| Market Research | 0 | $1,164,538 | 0 | 0 | 0 | 0.00 |
| Product Development | 0 | $807,000 | 0 | 0 | 0 | 0.00 |
| **Research, Evaluations & Pilots Segment Total** | **0** | **$1,971,538** | **0** | **0** | **0** | **0.00** |
| | | | | | | |
| PORTFOLIO SUBTOTAL | **1,561,621** | **$70,382,471** | **234,293** | **94,489** | **398,723,467** | **1.81** |
| | | | | | | |
| **Renewable Energy Segment - Solar*Rewards** | **232** | **$5,000,000** | **3,066** | **1,566** | **4,242,254** | **0.45** |
| | | | | | | |
| **Anticipated Alternative Filings** | | | | | | |
| CEE One-Stop Efficiency Shop | 1,128 | $10,400,000 | 11,000 | 10,786 | 35,046,403 | 1.87 |
| EnerChange | 0 | $418,500 | 0 | 0 | 0 | |
| Energy Smart | 0 | $327,750 | 0 | 0 | 0 | |
| Trillion BTU | 0 | $180,000 | 0 | 0 | 0 | |
| **Anticipated Alternative Filings Total** | **1,128** | **$11,326,250** | **11,000** | **10,786** | **35,046,403** | |
| | | | | | | |
| **Assessments Segment** | **0** | **$1,736,000** | **0** | **0** | **0** | |
| | | | | | | |
| **Electric Utility Infrastructure Segment** | **0** | **$0** | **0** | **0** | **0** | |
| | | | | | | |
| PORTFOLIO TOTAL | **1,562,981** | **$88,444,721** | **248,359** | **106,841** | **438,012,124** | |

## Executive Summary Table - Gas 2013

| 2013 | Gas Participants | Gas Budget | Dth Savings | Societal Test Ratio |
|---|---|---|---|---|
| **Business Segment** | | | | |
| Business New Construction | 14 | $443,688 | 24,018 | 1.14 |
| Commercial Efficiency | 4 | $211,178 | 12,023 | 2.31 |
| Computer Efficiency | 0 | $0 | 0 | |
| Cooling Efficiency | 0 | $0 | 0 | |
| Custom Efficiency | 39 | $633,706 | 25,253 | 2.47 |
| Data Center Efficiency | 0 | $0 | 0 | |
| Efficiency Controls | 27 | $206,988 | 20,324 | 2.09 |
| Fluid Systems Optimization | 0 | $0 | 0 | |
| Foodservice Equipment | 58 | $92,129 | 5,388 | 2.19 |
| Heating Efficiency | 633 | $1,553,325 | 190,028 | 2.26 |
| Lighting Efficiency | 0 | $0 | 0 | |
| Motor Efficiency | 0 | $0 | 0 | |
| Process Efficiency | 19 | $815,182 | 120,014 | 3.88 |
| Recommissioning | 30 | $126,038 | 14,071 | 3.20 |
| Self-Direct | 2 | $85,738 | 9,868 | 3.75 |
| Turn Key Services | 49 | $64,402 | 9,513 | 2.57 |
| **Business Segment Energy Efficiency Total** | **875** | **$4,232,373** | **430,500** | **2.43** |
| Electric Rate Savings | 0 | $0 | 0 | |
| Saver's Switch for Business | 0 | $0 | 0 | |
| **Business Segment Load Management Total** | **0** | **$0** | **0** | |
| Business Education | 1,900 | $37,412 | 0 | 0.00 |
| Small Business Lamp Recycling | 0 | $0 | 0 | |
| **Business Segment Indirect Total** | **1,900** | **$37,412** | **0** | **0.00** |
| **Business Segment Total** | **2,775** | **$4,269,785** | **430,500** | **2.43** |
| | | | | |
| **Residential Segment** | | | | |
| Energy Efficient Showerheads | 13,950 | $175,502 | 22,852 | 11.83 |
| Energy Feedback | 150,000 | $453,245 | 27,220 | 1.09 |
| ENERGY STAR Homes | 500 | $742,389 | 35,485 | 2.23 |
| Heating System Rebates | 5,777 | $928,352 | 82,800 | 1.91 |
| Home Energy Squad | 3,000 | $785,723 | 27,263 | 2.31 |
| Home Lighting | 0 | $0 | 0 | |
| Home Performance with ENERGY STAR® | 225 | $266,823 | 7,149 | 1.21 |
| Insulation Rebate | 1,049 | $323,651 | 14,455 | 1.43 |
| Refrigerator Recycling | 0 | $0 | 0 | |
| Residential Cooling | 0 | $0 | 0 | |
| School Education Kits | 20,000 | $482,038 | 21,597 | 4.50 |
| Water Heater Rebate | 1,330 | $177,146 | 3,461 | 0.68 |
| **Residential Segment Energy Efficiency Total** | **195,831** | **$4,334,869** | **242,281** | **2.12** |
| **Residential Segment Load Management - Saver's Switch** | **0** | **$0** | **0** | |
| Consumer Education | 382,912 | $540,806 | 0 | 0.00 |
| Home Energy Audit | 2,500 | $389,380 | 0 | 0.00 |
| Residential Lamp Recycling | 0 | $0 | 0 | |
| **Residential Segment Indirect Total** | **385,412** | **$930,186** | **0** | **0.00** |
| **Residential Segment Total** | **581,243** | **$5,265,055** | **242,281** | **1.92** |
| | | | | |
| **Low-Income Segment** | | | | |
| Home Energy Savings Program | 400 | $1,192,083 | 9,360 | 1.12 |
| Low-Income Home Energy Squad | 1,650 | $464,897 | 14,274 | 2.45 |
| Multi-Family Energy Savings Program | 0 | $0 | 0 | |
| **Low-Income Segment Total** | **2,050** | **$1,656,980** | **23,635** | **1.51** |
| | | | | |
| **Planning Segment** | | | | |
| Application Development and Maintenance | 0 | $267,246 | 0 | 0.00 |
| Advertising & Promotion | 0 | $572,000 | 0 | 0.00 |
| CIP Training | 0 | $40,000 | 0 | 0.00 |
| Regulatory Affairs | 0 | $131,500 | 0 | 0.00 |
| **Planning Segment Total** | **0** | **$1,010,746** | **0** | **0.00** |
| | | | | |
| **Research, Evaluations & Pilots Segment** | | | | |
| Market Research | 0 | $454,890 | 0 | 0.00 |
| Product Development | 0 | $227,972 | 0 | 0.00 |
| **Research, Evaluations & Pilots Segment Total** | **0** | **$682,862** | **0** | **0.00** |
| | | | | |
| PORTFOLIO SUBTOTAL | **586,068** | **$12,885,428** | **696,415** | **2.06** |
| | | | | |
| **Renewable Energy Segment - Solar*Rewards** | **0** | **$0** | **0** | |
| | | | | |
| **Anticipated Alternative Filings** | | | | |
| CEE One-Stop Efficiency Shop | 0 | $0 | 0 | |
| EnerChange | 0 | $46,500 | 0 | |
| Energy Smart | 0 | $17,250 | 0 | |
| Trillion BTU | 0 | $20,000 | 0 | |
| **Anticipated Alternative Filings Total** | **0** | **$83,750** | **0** | |
| | | | | |
| **Assessments Segment** | **0** | **$345,600** | **0** | |
| | | | | |
| **Electric Utility Infrastructure Segment** | **0** | **$0** | **0** | |
| | | | | |
| PORTFOLIO TOTAL | **586,068** | **$13,314,778** | **696,415** | |

## Executive Summary Table - Electric 2014

| 2014 | Electric Participants | Electric Budget | Customer kW | Generator kW | Generator kWh | Societal Test Ratio |
|---|---|---|---|---|---|---|
| **Business Segment** | | | | | | |
| Business New Construction | 49 | $6,055,734 | 6,083 | 5,975 | 25,085,206 | 1.35 |
| Commercial Efficiency | 20 | $1,837,293 | 1,527 | 1,033 | 8,861,195 | 1.62 |
| Computer Efficiency | 2,908 | $1,420,915 | 1,588 | 1,707 | 12,426,585 | 1.65 |
| Cooling Efficiency | 1,106 | $1,950,860 | 1,979 | 1,644 | 7,106,359 | 1.53 |
| Custom Efficiency | 123 | $3,074,265 | 3,677 | 1,773 | 17,140,222 | 1.68 |
| Data Center Efficiency | 15 | $848,062 | 807 | 557 | 7,050,853 | 3.10 |
| Efficiency Controls | 90 | $1,426,994 | 2,165 | 350 | 17,274,536 | 2.17 |
| Fluid Systems Optimization | 494 | $1,615,374 | 2,248 | 2,202 | 14,507,254 | 2.62 |
| Foodservice Equipment | 72 | $55,191 | 147 | 108 | 729,965 | 2.96 |
| Heating Efficiency | 0 | $0 | 0 | 0 | 0 | |
| Lighting Efficiency | 589 | $5,471,322 | 7,547 | 6,675 | 40,022,385 | 1.83 |
| Motor Efficiency | 877 | $4,335,454 | 7,217 | 6,057 | 36,021,638 | 2.22 |
| Process Efficiency | 81 | $6,909,437 | 12,314 | 9,076 | 75,856,071 | 2.71 |
| Recommissioning | 124 | $1,148,781 | 1,838 | 587 | 11,938,416 | 1.96 |
| Self-Direct | 15 | $2,743,423 | 4,831 | 3,258 | 14,876,387 | 1.52 |
| Turn Key Services | 391 | $1,502,201 | 2,108 | 666 | 7,668,306 | 1.79 |
| **Business Segment Energy Efficiency Total** | **6,954** | **$40,395,306** | **56,076** | **41,668** | **296,565,377** | **1.96** |
| Electric Rate Savings | 80 | $483,602 | 16,000 | 8,165 | 302,531 | 7.01 |
| Saver's Switch for Business | 1,151 | $2,037,295 | 12,620 | 3,256 | 21,090 | 1.55 |
| **Business Segment Load Management Total** | **1,231** | **$2,520,897** | **28,620** | **11,421** | **323,621** | **2.60** |
| Business Education | 14,000 | $247,498 | 0 | 0 | 0 | 0.00 |
| Small Business Lamp Recycling | 55,000 | $35,200 | 0 | 0 | 0 | 0.00 |
| | | **$282,698** | **0** | **0** | **0** | **0.00** |
| **Business Segment Total** | **77,185** | **$43,198,901** | **84,696** | **53,088** | **296,888,998** | **1.97** |
| | | | | | | |
| **Residential Segment** | | | | | | |
| Energy Efficient Showerheads | 1,050 | $15,025 | 175 | 0 | 360,781 | 8.51 |
| Energy Feedback | 142,500 | $1,017,621 | 851 | 635 | 8,142,278 | 1.08 |
| ENERGY STAR Homes | 860 | $204,376 | 297 | 106 | 900,058 | 1.70 |
| Heating System Rebates | 7,000 | $759,010 | 1,750 | 1,343 | 4,745,263 | 1.45 |
| Home Energy Squad | 5,501 | $1,229,621 | 3,468 | 583 | 2,820,466 | 1.25 |
| Home Lighting | 594,824 | $4,598,468 | 60,027 | 9,176 | 69,378,126 | 2.53 |
| Home Performance with ENERGY STAR® | 225 | $98,853 | 211 | 140 | 162,570 | 1.29 |
| Insulation Rebate | 296 | $89,082 | 467 | 240 | 340,788 | 1.41 |
| Refrigerator Recycling | 6,000 | $848,163 | 1,290 | 778 | 6,787,010 | 3.26 |
| Residential Cooling | 9,987 | $4,735,920 | 9,153 | 9,022 | 5,417,907 | 1.04 |
| School Education Kits | 20,000 | $617,668 | 1,890 | 155 | 1,957,614 | 1.38 |
| Water Heater Rebate | 0 | $0 | 0 | 0 | 0 | |
| **Residential Segment Energy Efficiency Total** | **788,243** | **$14,213,807** | **79,579** | **22,178** | **101,012,862** | **1.70** |
| **Residential Segment Load Management - Saver's Switch** | **20,000** | **$4,961,935** | **60,413** | **17,690** | **177,738** | **3.47** |
| Consumer Education | 433,854 | $776,640 | 0 | 0 | 0 | 0.00 |
| Home Energy Audit | 3,300 | $576,731 | 0 | 0 | 0 | 0.00 |
| Residential Lamp Recycling | 315,000 | $201,600 | 0 | 0 | 0 | 0.00 |
| | | **$1,554,971** | **0** | **0** | **0** | **0.00** |
| **Residential Segment Total** | **1,560,397** | **$20,730,713** | **139,991** | **39,869** | **101,190,600** | **1.85** |
| | | | | | | |
| **Low-Income Segment** | | | | | | |
| Home Energy Savings Program | 2,100 | $1,358,641 | 563 | 186 | 915,688 | 0.66 |
| Low-Income Home Energy Squad | 1,650 | $391,308 | 1,228 | 184 | 994,948 | 1.47 |
| Multi-Family Energy Savings Program | 596 | $818,914 | 478 | 129 | 722,431 | 0.69 |
| **Low-Income Segment Total** | **4,346** | **$2,568,863** | **2,269** | **498** | **2,633,067** | **0.75** |
| | | | | | | |
| **Planning Segment** | | | | | | |
| Application Development and Maintenance | 0 | $1,101,600 | 0 | 0 | 0 | 0.00 |
| Advertising & Promotion | 0 | $2,574,000 | 0 | 0 | 0 | 0.00 |
| CIP Training | 0 | $125,000 | 0 | 0 | 0 | 0.00 |
| Regulatory Affairs | 0 | $415,743 | 0 | 0 | 0 | 0.00 |
| **Planning Segment Total** | **0** | **$4,216,343** | **0** | **0** | **0** | **0.00** |
| | | | | | | |
| **Research, Evaluations & Pilots Segment** | | | | | | |
| Market Research | 0 | $574,920 | 0 | 0 | 0 | 0.00 |
| Product Development | 0 | $807,000 | 0 | 0 | 0 | 0.00 |
| **Research, Evaluations & Pilots Segment Total** | **0** | **$1,381,920** | **0** | **0** | **0** | **0.00** |
| | | | | | | |
| PORTFOLIO SUBTOTAL | **1,641,928** | **$72,096,739** | **226,956** | **93,455** | **400,712,665** | **1.85** |
| | | | | | | |
| **Renewable Energy Segment - Solar*Rewards** | **232** | **$5,000,000** | **3,066** | **1,566** | **4,242,254** | **0.45** |
| | | | | | | |
| **Anticipated Alternative Filings** | | | | | | |
| CEE One-Stop Efficiency Shop | 1,128 | $10,608,000 | 11,000 | 10,786 | 35,046,403 | 1.85 |
| EnerChange | 0 | $418,500 | 0 | 0 | 0 | |
| Energy Smart | 0 | $342,000 | 0 | 0 | 0 | |
| Trillion BTU | 0 | $180,000 | 0 | 0 | 0 | |
| **Anticipated Alternative Filings Total** | **1,128** | **$11,548,500** | **11,000** | **10,786** | **35,046,403** | |
| | | | | | | |
| **Assessments Segment** | **0** | **$1,736,000** | **0** | **0** | **0** | |
| | | | | | | |
| **Electric Utility Infrastructure Segment** | **0** | **$0** | **0** | **0** | **0** | |
| | | | | | | |
| PORTFOLIO TOTAL | **1,643,288** | **$90,381,239** | **241,022** | **105,807** | **440,001,322** | |

## Executive Summary Table - Gas 2014

| 2014 | Gas Participants | Gas Budget | Dth Savings | Societal Test Ratio |
|---|---|---|---|---|
| **Business Segment** | | | | |
| Business New Construction | 13 | $450,056 | 23,235 | 1.14 |
| Commercial Efficiency | 8 | $335,181 | 20,301 | 2.31 |
| Computer Efficiency | 0 | $0 | 0 | |
| Cooling Efficiency | 0 | $0 | 0 | |
| Custom Efficiency | 53 | $713,216 | 39,984 | 2.47 |
| Data Center Efficiency | 0 | $0 | 0 | |
| Efficiency Controls | 33 | $249,168 | 25,014 | 2.09 |
| Fluid Systems Optimization | 0 | $0 | 0 | |
| Foodservice Equipment | 82 | $108,101 | 7,207 | 2.19 |
| Heating Efficiency | 704 | $1,578,882 | 200,010 | 2.26 |
| Lighting Efficiency | 0 | $0 | 0 | |
| Motor Efficiency | 0 | $0 | 0 | |
| Process Efficiency | 21 | $851,073 | 135,761 | 3.88 |
| Recommissioning | 30 | $127,139 | 14,071 | 3.20 |
| Self-Direct | 3 | $125,437 | 14,801 | 3.75 |
| Turn Key Services | 54 | $68,767 | 10,529 | 2.57 |
| **Business Segment Energy Efficiency Total** | **1,002** | **$4,607,020** | **490,913** | **2.43** |
| Electric Rate Savings | 0 | $0 | 0 | |
| Saver's Switch for Business | 0 | $0 | 0 | |
| **Business Segment Load Management Total** | **0** | **$0** | **0** | |
| Business Education | 1,900 | $37,412 | 0 | 0.00 |
| Small Business Lamp Recycling | 0 | $0 | 0 | |
| | **1,900** | **$37,412** | **0** | **0.00** |
| **Business Segment Total** | **2,902** | **$4,644,432** | **490,913** | **2.43** |
| | | | | |
| **Residential Segment** | | | | |
| Energy Efficient Showerheads | 13,950 | $182,087 | 22,852 | 11.83 |
| Energy Feedback | 142,500 | $415,873 | 25,859 | 1.09 |
| ENERGY STAR Homes | 500 | $781,748 | 35,485 | 2.23 |
| Heating System Rebates | 5,777 | $1,173,079 | 17,418 | 1.91 |
| Home Energy Squad | 3,000 | $800,059 | 28,229 | 2.31 |
| Home Lighting | 0 | $0 | 0 | |
| Home Performance with ENERGY STAR® | 225 | $271,998 | 7,210 | 1.21 |
| Insulation Rebate | 1,092 | $334,065 | 15,033 | 1.43 |
| Refrigerator Recycling | 0 | $0 | 0 | |
| Residential Cooling | 0 | $0 | 0 | |
| School Education Kits | 20,000 | $483,082 | 21,597 | 4.50 |
| Water Heater Rebate | 1,380 | $187,995 | 3,677 | 0.68 |
| **Residential Segment Energy Efficiency Total** | **188,424** | **$4,629,986** | **177,360** | **2.12** |
| **Residential Segment Load Management - Saver's Switch** | **0** | **$0** | **0** | |
| Consumer Education | 382,912 | $540,806 | 0 | 0.00 |
| Home Energy Audit | 2,500 | $402,739 | 0 | 0.00 |
| Residential Lamp Recycling | 0 | $0 | 0 | |
| | **385,412** | **$943,545** | **0** | **0.00** |
| **Residential Segment Total** | **573,836** | **$5,573,531** | **177,360** | **1.92** |
| | | | | |
| **Low-Income Segment** | | | | |
| Home Energy Savings Program | 400 | $1,188,045 | 9,360 | 1.12 |
| Low-Income Home Energy Squad | 1,650 | $468,136 | 14,274 | 2.45 |
| Multi-Family Energy Savings Program | 0 | $0 | 0 | |
| **Low-Income Segment Total** | **2,050** | **$1,656,181** | **23,635** | **1.51** |
| | | | | |
| **Planning Segment** | | | | |
| Application Development and Maintenance | 0 | $267,246 | 0 | 0.00 |
| Advertising & Promotion | 0 | $588,000 | 0 | 0.00 |
| CIP Training | 0 | $40,000 | 0 | 0.00 |
| Regulatory Affairs | 0 | $134,548 | 0 | 0.00 |
| **Planning Segment Total** | **0** | **$1,029,794** | **0** | **0.00** |
| | | | | |
| **Research, Evaluations & Pilots Segment** | | | | |
| Market Research | 0 | $443,333 | 0 | 0.00 |
| Product Development | 0 | $227,972 | 0 | 0.00 |
| **Research, Evaluations & Pilots Segment Total** | **0** | **$671,305** | **0** | **0.00** |
| | | | | |
| **PORTFOLIO SUBTOTAL** | **578,788** | **$13,575,243** | **691,908** | **2.06** |
| | | | | |
| **Renewable Energy Segment - Solar*Rewards** | **0** | **$0** | **0** | 0 |
| | | | | |
| **Anticipated Alternative Filings** | | | | |
| CEE One-Stop Efficiency Shop | 0 | $0 | 0 | |
| EnerChange | 0 | $46,500 | 0 | |
| Energy Smart | 0 | $18,000 | 0 | |
| Trillion BTU | 0 | $20,000 | 0 | |
| **Anticipated Alternative Filings Total** | **0** | **$84,500** | **0** | |
| | | | | |
| **Assessments Segment** | **0** | **$345,600** | **0** | |
| | | | | |
| **Electric Utility Infrastructure Segment** | **0** | **$0** | **0** | |
| | | | | |
| **PORTFOLIO TOTAL** | **578,788** | **$14,005,343** | **691,908** | |

## Executive Summary Table - Electric 2015

| 2015 | Electric Participants | Electric Budget | Customer kW | Generator kW | Generator kWh | Societal Test Ratio |
|---|---|---|---|---|---|---|
| **Business Segment** | | | | | | |
| Business New Construction | 43 | $5,337,135 | 5,094 | 4,988 | 21,048,986 | 1.38 |
| Commercial Efficiency | 37 | $3,171,977 | 2,865 | 2,094 | 16,132,446 | 1.80 |
| Computer Efficiency | 2,911 | $1,490,993 | 1,588 | 1,707 | 12,426,585 | 1.67 |
| Cooling Efficiency | 1,109 | $1,963,169 | 1,982 | 1,645 | 7,134,438 | 1.58 |
| Custom Efficiency | 128 | $3,172,659 | 3,816 | 1,840 | 17,787,022 | 1.74 |
| Data Center Efficiency | 18 | $1,010,286 | 1,183 | 796 | 10,380,517 | 3.01 |
| Efficiency Controls | 92 | $1,490,726 | 2,213 | 358 | 17,662,728 | 2.24 |
| Fluid Systems Optimization | 551 | $1,860,934 | 2,646 | 2,573 | 16,634,440 | 2.74 |
| Foodservice Equipment | 72 | $58,727 | 147 | 108 | 729,965 | 3.02 |
| Heating Efficiency | 0 | $0 | 0 | 0 | 0 | |
| Lighting Efficiency | 449 | $4,917,319 | 5,694 | 5,041 | 30,027,945 | 1.70 |
| Motor Efficiency | 877 | $4,354,982 | 7,217 | 6,057 | 36,021,638 | 2.30 |
| Process Efficiency | 91 | $6,609,504 | 11,586 | 8,565 | 71,224,992 | 2.78 |
| Recommissioning | 124 | $1,151,320 | 1,838 | 587 | 11,938,416 | 2.06 |
| Self-Direct | 20 | $3,616,137 | 6,441 | 4,344 | 19,835,182 | 1.57 |
| Turn Key Services | 421 | $1,605,351 | 2,271 | 717 | 8,259,652 | 1.87 |
| **Business Segment Energy Efficiency Total** | **6,942** | **$41,811,218** | **56,581** | **41,419** | **297,244,952** | **2.00** |
| Electric Rate Savings | 80 | $492,822 | 16,000 | 8,165 | 302,531 | 7.05 |
| Saver's Switch for Business | 1,151 | $2,106,903 | 12,620 | 3,256 | 21,090 | 1.54 |
| **Business Segment Load Management Total** | **1,231** | **$2,599,725** | **28,620** | **11,421** | **323,621** | **2.58** |
| Business Education | 14,000 | $247,498 | 0 | 0 | 0 | 0.00 |
| Small Business Lamp Recycling | 60,000 | $39,600 | 0 | 0 | 0 | 0.00 |
| **Business Segment Indirect Total** | **74,000** | **$287,098** | **0** | **0** | **0** | **0.00** |
| **Business Segment Total** | **82,173** | **$44,698,041** | **85,201** | **52,840** | **297,568,573** | **2.01** |
| | | | | | | |
| **Residential Segment** | | | | | | |
| Energy Efficient Showerheads | 1,050 | $15,747 | 175 | 0 | 360,781 | 8.39 |
| Energy Feedback | 190,375 | $1,530,056 | 1,297 | 967 | 12,406,647 | 1.23 |
| ENERGY STAR Homes | 860 | $199,145 | 281 | 105 | 885,775 | 1.77 |
| Heating System Rebates | 7,000 | $759,470 | 1,750 | 1,343 | 4,745,263 | 1.49 |
| Home Energy Squad | 5,499 | $1,239,558 | 2,925 | 537 | 2,384,706 | 1.18 |
| Home Lighting | 675,611 | $4,857,433 | 55,664 | 8,520 | 64,376,286 | 2.27 |
| Home Performance with ENERGY STAR® | 225 | $99,995 | 200 | 138 | 156,325 | 1.31 |
| Insulation Rebate | 311 | $93,156 | 493 | 250 | 361,265 | 1.46 |
| Refrigerator Recycling | 6,500 | $920,950 | 1,398 | 843 | 7,352,594 | 3.42 |
| Residential Cooling | 10,114 | $4,768,217 | 9,254 | 9,121 | 5,479,306 | 1.07 |
| School Education Kits | 20,000 | $618,350 | 1,624 | 131 | 1,714,351 | 1.28 |
| Water Heater Rebate | 0 | $0 | 0 | 0 | 0 | |
| **Residential Segment Energy Efficiency Total** | **917,545** | **$15,102,077** | **75,061** | **21,957** | **100,223,299** | **1.64** |
| **Residential Segment Load Management - Saver's Switch** | **20,000** | **$5,083,549** | **60,413** | **17,690** | **177,738** | **3.47** |
| Consumer Education | 433,854 | $765,640 | 0 | 0 | 0 | 0.00 |
| Home Energy Audit | 3,300 | $596,640 | 0 | 0 | 0 | 0.00 |
| Residential Lamp Recycling | 325,000 | $214,500 | 0 | 0 | 0 | 0.00 |
| **Residential Segment Indirect Total** | **762,154** | **$1,576,780** | **0** | **0** | **0** | **0.00** |
| **Residential Segment Total** | **1,699,699** | **$21,762,406** | **135,474** | **39,647** | **100,401,037** | **1.80** |
| | | | | | | |
| **Low-Income Segment** | | | | | | |
| Home Energy Savings Program | 2,000 | $1,307,042 | 505 | 174 | 842,035 | 0.66 |
| Low-Income Home Energy Squad | 1,650 | $394,569 | 1,142 | 177 | 925,303 | 1.43 |
| Multi-Family Energy Savings Program | 596 | $818,976 | 430 | 124 | 677,988 | 0.68 |
| **Low-Income Segment Total** | **4,246** | **$2,520,587** | **2,076** | **476** | **2,445,325** | **0.75** |
| | | | | | | |
| **Planning Segment** | | | | | | |
| Application Development and Maintenance | 0 | $1,101,600 | 0 | 0 | 0 | 0.00 |
| Advertising & Promotion | 0 | $2,628,000 | 0 | 0 | 0 | 0.00 |
| CIP Training | 0 | $124,999 | 0 | 0 | 0 | 0.00 |
| Regulatory Affairs | 0 | $435,669 | 0 | 0 | 0 | 0.00 |
| **Planning Segment Total** | **0** | **$4,290,268** | **0** | **0** | **0** | **0.00** |
| | | | | | | |
| **Research, Evaluations & Pilots Segment** | | | | | | |
| Market Research | 0 | $998,988 | 0 | 0 | 0 | 0.00 |
| Product Development | 0 | $807,000 | 0 | 0 | 0 | 0.00 |
| **Research, Evaluations & Pilots Segment Total** | **0** | **$1,805,988** | **0** | **0** | **0** | **0.00** |
| | | | | | | |
| PORTFOLIO SUBTOTAL | **1,786,119** | **$75,077,290** | **222,750** | **92,962** | **400,414,935** | **1.86** |
| | | | | | | |
| **Renewable Energy Segment - Solar*Rewards** | **232** | **$5,000,000** | **3,066** | **1,566** | **4,242,254** | **0.45** |
| | | | | | | |
| **Anticipated Alternative Filings** | | | | | | |
| CEE One-Stop Efficiency Shop | 1,128 | $10,820,160 | 11,000 | 10,786 | 35,046,403 | 1.83 |
| EnerChange | 0 | $418,500 | 0 | 0 | 0 | |
| Energy Smart | 0 | $356,250 | 0 | 0 | 0 | |
| Trillion BTU | 0 | $180,000 | 0 | 0 | 0 | |
| **Anticipated Alternative Filings Total** | **1,128** | **$11,774,910** | **11,000** | **10,786** | **35,046,403** | |
| | | | | | | |
| **Assessments Segment** | **0** | **$1,736,000** | **0** | **0** | **0** | |
| | | | | | | |
| **Electric Utility Infrastructure Segment** | **0** | **$0** | **0** | **0** | **0** | |
| | | | | | | |
| PORTFOLIO TOTAL | **1,787,479** | **$93,588,200** | **236,816** | **105,314** | **439,703,592** | |

## Executive Summary Table - Gas 2015

| 2015 | Gas Participants | Gas Budget | Dth Savings | Societal Test Ratio |
|---|---|---|---|---|
| **Business Segment** | | | | |
| Business New Construction | 12 | $419,412 | 20,739 | 1.14 |
| Commercial Efficiency | 13 | $482,239 | 25,591 | 2.31 |
| Computer Efficiency | 0 | $0 | 0 | |
| Cooling Efficiency | 0 | $0 | 0 | |
| Custom Efficiency | 53 | $719,247 | 39,984 | 2.47 |
| Data Center Efficiency | 0 | $0 | 0 | |
| Efficiency Controls | 33 | $238,902 | 25,014 | 2.09 |
| Fluid Systems Optimization | 0 | $0 | 0 | |
| Foodservice Equipment | 82 | $107,430 | 7,207 | 2.19 |
| Heating Efficiency | 691 | $1,578,199 | 195,006 | 2.26 |
| Lighting Efficiency | 0 | $0 | 0 | |
| Motor Efficiency | 0 | $0 | 0 | |
| Process Efficiency | 23 | $862,029 | 137,395 | 3.88 |
| Recommissioning | 30 | $127,259 | 14,071 | 3.20 |
| Self-Direct | 4 | $165,145 | 19,735 | 3.75 |
| Turn Key Services | 58 | $72,425 | 11,342 | 2.57 |
| **Business Segment Energy Efficiency Total** | **1,000** | **$4,772,287** | **496,084** | **2.43** |
| Electric Rate Savings | 0 | $0 | 0 | |
| Saver's Switch for Business | 0 | $0 | 0 | |
| **Business Segment Load Management Total** | **0** | **$0** | **0** | |
| Business Education | 1,900 | $37,412 | 0 | 0.00 |
| Small Business Lamp Recycling | 0 | $0 | 0 | |
| **Business Segment Indirect Total** | **1,900** | **$37,412** | **0** | **0.00** |
| **Business Segment Total** | **2,900** | **$4,809,699** | **496,084** | **2.43** |
| | | | | |
| **Residential Segment** | | | | |
| Energy Efficient Showerheads | 13,950 | $191,126 | 22,852 | 11.83 |
| Energy Feedback | 135,375 | $399,534 | 24,566 | 1.09 |
| ENERGY STAR Homes | 500 | $775,123 | 35,485 | 2.23 |
| Heating System Rebates | 5,777 | $1,200,159 | 17,736 | 1.91 |
| Home Energy Squad | 3,000 | $808,680 | 28,328 | 2.31 |
| Home Lighting | 0 | $0 | 0 | |
| Home Performance with ENERGY STAR® | 225 | $277,193 | 7,259 | 1.21 |
| Insulation Rebate | 1,133 | $344,870 | 15,615 | 1.43 |
| Refrigerator Recycling | 0 | $0 | 0 | |
| Residential Cooling | 0 | $0 | 0 | |
| School Education Kits | 20,000 | $484,023 | 21,597 | 4.50 |
| Water Heater Rebate | 1,380 | $194,914 | 3,677 | 0.68 |
| **Residential Segment Energy Efficiency Total** | **181,340** | **$4,675,622** | **177,115** | **2.12** |
| **Residential Segment Load Management - Saver's Switch** | **0** | **$0** | **0** | |
| Consumer Education | 382,912 | $540,806 | 0 | 0.00 |
| Home Energy Audit | 2,500 | $416,500 | 0 | 0.00 |
| Residential Lamp Recycling | 0 | $0 | 0 | |
| **Residential Segment Indirect Total** | **385,412** | **$957,306** | **0** | **0.00** |
| **Residential Segment Total** | **566,752** | **$5,632,928** | **177,115** | **1.92** |
| | | | | |
| **Low-Income Segment** | | | | |
| Home Energy Savings Program | 400 | $1,167,851 | 9,001 | 1.12 |
| Low-Income Home Energy Squad | 1,650 | $468,370 | 14,274 | 2.45 |
| Multi-Family Energy Savings Program | 0 | $0 | 0 | |
| **Low-Income Segment Total** | **2,050** | **$1,636,221** | **23,275** | **1.51** |
| | | | | |
| **Planning Segment** | | | | |
| Application Development and Maintenance | 0 | $267,246 | 0 | 0.00 |
| Advertising & Promotion | 0 | $610,000 | 0 | 0.00 |
| CIP Training | 0 | $40,000 | 0 | 0.00 |
| Regulatory Affairs | 0 | $140,687 | 0 | 0.00 |
| **Planning Segment Total** | **0** | **$1,057,933** | **0** | **0.00** |
| | | | | |
| **Research, Evaluations & Pilots Segment** | | | | |
| Market Research | 0 | $189,070 | 0 | 0.00 |
| Product Development | 0 | $227,972 | 0 | 0.00 |
| **Research, Evaluations & Pilots Segment Total** | **0** | **$417,042** | **0** | **0.00** |
| | | | | |
| PORTFOLIO SUBTOTAL | **571,702** | **$13,553,823** | **696,474** | **2.06** |
| | | | | |
| **Renewable Energy Segment - Solar*Rewards** | **0** | **$0** | **0** | |
| | | | | |
| **Anticipated Alternative Filings** | | | | |
| CEE One-Stop Efficiency Shop | 0 | $0 | 0 | |
| EnerChange | 0 | $46,500 | 0 | |
| Energy Smart | 0 | $18,750 | 0 | |
| Trillion BTU | 0 | $20,000 | 0 | |
| **Anticipated Alternative Filings Total** | **0** | **$85,250** | **0** | |
| | | | | |
| **Assessments Segment** | **0** | **$345,600** | **0** | |
| | | | | |
| **Electric Utility Infrastructure Segment** | **0** | **$0** | **0** | |
| | | | | |
| PORTFOLIO TOTAL | **571,702** | **$13,984,673** | **696,474** | |

# 2013-2015 Triennial Plan Program Summary

## Electric

| Three Year Summary | Electric Participants | Electric Budget | Customer kW | Generator kW | Generator kWh |
|---|---|---|---|---|---|
| 2013 | 1,562,981 | $88,444,721 | 248,359 | 106,841 | 438,012,124 |
| 2014 | 1,643,288 | $90,381,239 | 241,022 | 105,807 | 440,001,322 |
| 2015 | 1,787,479 | $93,588,200 | 236,816 | 105,314 | 439,703,592 |
| **2013 - 2015 Total** | **4,993,747** | **$272,414,161** | **726,197** | **317,963** | **1,317,717,037** |

## Gas

| Three Year Summary | Gas Participants | Gas Budget | Dth Savings |
|---|---|---|---|
| 2013 | 586,068 | $13,314,778 | 696,415 |
| 2014 | 578,788 | $14,005,343 | 691,908 |
| 2015 | 571,702 | $13,984,673 | 696,474 |
| **2013 - 2015 Total** | **1,736,558** | **$41,304,794** | **2,084,797** |

# Appendix C
# Project Operational and Cost Data

**Table C1a**
**Black Dog Unit 6**
**Project Generating Capability**

| **Summer Conditions (95°F, 30% Relative Humidity)** | | | |
|---|---|---|---|
| **Capability** | | **Net Heat Rate (Btu/kWh) (HHV)** | **Efficiency (%) (HHV)** |
| **% of Base** | **MW** | | |
| ***[TRADE SECRET DATA BEGINS…*** | | | |
| 100 (Full Load)* | | | |
| ***…TRADE SECRET DATA ENDS]*** | | | |
| **Winter Conditions (-5°F, 60% Relative Humidity)** | | | |
| **Capability** | | **Net Heat Rate (Btu/kWh) (HHV)** | **Efficiency (%) (HHV)** |
| **% of Base** | **MW** | | |
| ***[TRADE SECRET DATA BEGINS…*** | | | |
| 100 (Full Load)* | | | |
| ***…TRADE SECRET DATA ENDS]*** | | | |
| **Reference Temperature Conditions (59°F, 60% Relative Humidity)** | | | |
| **Capability** | | **Net Heat Rate (Btu/kWh) (HHV)** | **Efficiency (%) (HHV)** |
| **% of Base** | **MW** | | |
| ***[TRADE SECRET DATA BEGINS…*** | | | |
| 50 | | | |
| 60 | | | |
| 70 | | | |
| 80 | | | |
| 90 | | | |
| 100 (Full Load)* | | | |
| *The facility will typically run up to its best efficiency load point. | | | |
| ***…TRADE SECRET DATA ENDS]*** | | | |

**Table C1b**
**Red River Valley**
**Project Generating Capability (Applies to Each Unit – 1 and 2)**

| Summer Conditions (88°F, 42% Relative Humidity) | | | |
|---|---|---|---|
| Capability | | Net Heat Rate (Btu/kWh) (HHV) | Efficiency (%) (HHV) |
| % of Base | MW | | |
| *[TRADE SECRET DATA BEGINS…* | | | |
| 100 (Full Load)* | | | |
| *…TRADE SECRET DATA ENDS]* | | | |
| **Winter Conditions (-5°F, 100% Relative Humidity)** | | | |
| **Capability** | | **Net Heat Rate (Btu/kWh) (HHV)** | **Efficiency (%) (HHV)** |
| **% of Base** | **MW** | | |
| *[TRADE SECRET DATA BEGINS…* | | | |
| 100 (Full Load)* | | | |
| *…TRADE SECRET DATA ENDS]* | | | |
| **Reference Temperature Conditions (41°F, 70% Relative Humidity)** | | | |
| **Capability** | | **Net Heat Rate (Btu/kWh) (HHV)** | **Efficiency (%) (HHV)** |
| **% of Base** | **MW** | | |
| *[TRADE SECRET DATA BEGINS…* | | | |
| 50 | | | |
| 60 | | | |
| 70 | | | |
| 80 | | | |
| 90 | | | |
| 100 (Full Load)* | | | |
| *The facility will typically run up to its best efficiency load point. | | | |
| *…TRADE SECRET DATA ENDS]* | | | |

**Table C2a**
**Project Fuel Requirements – Black Dog Unit 6**

| Rule Reference | Description | Project Data, per Unit |
|---|---|---|
| | | ***[TRADE SECRET DATA BEGINS…*** |
| 7849.0320, C(1) | Fuel (Natural Gas) Source | |
| 7849.0320, C(2) | Fuel Requirement<br>•summer, peak (95F)<br>•winter, peak (-5F)<br>•reference temperature, base load (59F)<br>•Annual consumption (59F) | |
| 7849.0320, C(3) | Heat Input (HHV)<br>•summer, peak (95F)<br>•winter, peak (-5F)<br>•reference temperature, base load (59F) | |
| 7849.0320, C(4) | Fuel (natural gas) Heat Value | |
| 7849.0320, C(5) | Fuel Content:<br>Sulfur<br>Ash<br>Moisture Content | |
| | | ***…TRADE SECRET DATA ENDS]*** |

**Table C2b – North Dakota**
**Project Fuel Requirements, per Unit**

| Rule Reference | Description | Project Data, per Unit |
|---|---|---|
| | | ***[TRADE SECRET DATA BEGINS…*** |
| 7849.0320, C(1) | Fuel (Natural Gas) Source | |
| 7849.0320, C(2) | Fuel Requirement<br>•summer, peak (88F)<br>•winter, peak (-5F)<br>•reference temperature, base load (41F)<br>•Annual consumption (41F) | |
| 7849.0320, C(3) | Heat Input (HHV)<br>•summer, peak (88F)<br>•winter, peak (-5F)<br>•reference temperature, base load (41F) | |
| 7849.0320, C(4) | Fuel (natural gas) Heat Value | |
| 7849.0320, C(5) | Fuel Content (Gas):<br>Sulfur<br>Ash<br>Moisture Content | |
| | | ***…TRADE SECRET DATA ENDS]*** |

**Table C3a**
**Project Cost Summary – Black Dog**

| **Item** | **Black Dog Unit 6** | | |
|---|---|---|---|
| Unit | 6 | 6 (Option 1) | 6 (Option 2) |
| In-Service Date | March 2017 | March 2018 | March 2019 |
| | ***[TRADE SECRET DATA BEGINS…*** | | |
| Project Base Capacity Cost | | | |
| Base Summer Capacity Costs in $/kW | | | |
| Transmission Cost | | | |
| Gas Cost | | | |
| Base Total Cost in $/kWh | | | |
| Annual Revenue Requirement in $/kWh (In-Service Year) | | | |
| Fuel Costs in $/kWh (In-Service Year) | | | |
| Variable O&M Costs in $/kWh ((In-Service Year) | | | |
| Estimated Effect on Rates $/kWh (MN & Total System) | | | |
| Sunk Costs if Canceled | | | |
| Estimated number of construction jobs | | | |
| Estimated amount of construction payroll to economy | | | |
| Estimated number of operations jobs | | | |
| | | | |
| | ***…TRADE SECRET DATA ENDS]*** | | |

**Table C3b**
**Project Cost Summary – North Dakota**

| Item | North Dakota Units 1 and 2 | |
|---|---|---|
| Unit | 1 | 2 |
| In-Service Date | March 2018 | February 2019 |
| | ***[TRADE SECRET DATA BEGINS…*** | |
| Project Base Capacity Cost | | |
| Base Summer Capacity Costs in $/kW | | |
| Transmission Cost | | |
| Gas Cost | | |
| Base Total Cost in $/kWh | | |
| Annual Revenue Requirement in $/kWh (In-Service Year) | | |
| Fuel Costs in $/kWh (In-Service Year) | | |
| Variable O&M Costs in $/kWh ((In-Service Year) | | |
| Estimated Effect on Rates $/kWh (MN & Total System) | | |
| Sunk Costs if Canceled | | |
| Estimated number of construction jobs | | |
| Estimated amount of construction payroll to economy | | |
| Estimated number of operations jobs | | |
| | | |
| | ***…TRADE SECRET DATA ENDS]*** | |

**Table C4a**
**Black Dog Unit 6**

| Rule Reference | Description | Project Data |
|---|---|---|
| 7849.0250, A(1) | Nominal Generating Capability of each Unit | about 214 MW |
| 7849.0250, A(2) | Operating Cycle | Simple Cycle |
| 7849.0250, A(2) | Expected Average Annual Capacity Factor | 4 to 10 percent |
| 7849.0250, C(2) | Service Life | 35 Years |
| 7849.0250, C(3) | Estimated Average Annual Availability | > 95 percent |
| 7849.0320, A | Estimated Land Requirements | 0 acres (inside existing structure) |
| 7849.0320, E (1) | Estimated Maximum Groundwater Pumping Rate for each Unit<br><br>Surface Water Appropriation | 50 GPM peak, 34 GPM daily average during Summer operation for evaporative cooling<br>0 cfs for Project, 633 cfs for Site |
| 7849.0320, E (2) | Estimated Annual Project Groundwater Appropriation (assuming RO purification process) for existing Units 2 and 5 | 1.2 million gallons/year or 3.7 acre-feet/year<br>(X% of site appropriation) |
| 7849.0320, E (3) | Annual Project Surface Water Consumption<br><br>Unit 6 | 215,100 acre-feet<br>(50% of site appropriation) for existing Units 2 and 5<br>0 |

**Table C4b**
**Red River Valley Units 1 and 2**

| Rule Reference | Description | Project Data |
|---|---|---|
| 7849.0250, A(1) | Nominal Generating Capability of each Unit | about 214 MW |
| 7849.0250, A(2) | Operating Cycle | Simple Cycle |
| 7849.0250, A(2) | Expected Annual Capacity Factor | 4 to 10 percent |
| 7849.0250, C(2) | Service Life | 35 Years |
| 7849.0250, C(3) | Estimated Average Annual Availability | > 95 percent |
| 7849.0320, A | Estimated Land Requirements | < 35 acres on site of approximately 160 acres |
| 7849.0320, E (1) | Estimated Maximum Groundwater Pumping Rate for each Unit<br><br>Surface Water Appropriation | 50 GPM peak, 34 GPM daily average during Summer operation for evaporative cooling<br>0 cfs for Project, 633 cfs for Site |
| 7849.0320, E (2) | Estimated Annual Project Groundwater Appropriation (assuming RO purification process) | 1.2 million gallons/year or 3.7 acre-feet/year<br>0 if water is brought in by truck |
| 7849.0320, E (3) | Annual Project<br>Surface Water Consumption<br>Unit 1<br>Unit 2 | <br><br>0<br>0 |

# Strategist Assumptions Documentation - *Unit Performance & Cost Estimate*

**PROJECT:** Black Dog Unit 6 CT (2017)

**PREPARED BY:** *Greg Ford/Elizabeth Karels*
*4/8/2013*

**PROJECT/UNIT DESCRIPTION AND SOURCE DOCUMENTATION:**

*[TRADE SECRET DATA BEGINS…*

*…TRADE SECRET ENDS]*

**IN-SERVICE DATE:** *3/1/2017*
**RETIREMENT DATE:** *12/31/2051*

**In-service:** Strategist will assume in-service at the 1st of the month.
**Retirement:** Strategist will assume retirement on the last day of the month.

**NET CAPACITY :**

| | | Summer | Average | Winter |
|---|---|---|---|---|
| Ambient Conditions Assumptions | | *95F* | 59 F | -5 F |
| | | *[TRADE SECRET DATA BEGINS…* | | |
| Minimum Capacity | (50%) | | | |
| Load Point 2 | (60%) | | | |
| Load Point 3 | (70%) | | | |
| Load Point 4 | (80%) | | | |
| Load Point 5 | (90%) | | | |
| Maximum Capacity | (100%) | | | |
| | | *…TRADE SECRET DATA ENDS]* | | |

**Minimum Capacity**: For a combined cycle unit it should be the minimum generation in combined cycle configuration. Not CT only using bypass stacks.
**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:**
**Emergency Capacity:** Strategist will not dispatch a unit at this level, but the unit will be accredited this capacity for loads and resource calculations. This input is commonly used for coal plants with "gas topping".

**HEAT RATE:**

*[TRADE SECRET DATA BEGINS…*

| | | Average |
|---|---|---|
| Minimum Capacity | (50%) | |
| Load Point 2 | (60%) | |
| Load Point 3 | (70%) | |
| Load Point 4 | (80%) | |
| Load Point 5 | (90%) | |
| Maximum Capacity | (100%) | |
| Maximum With Ducts | | |

*…TRADE SECRET DATA ENDS]*

**Heat Rate:** Strategist can only model a single heat rate curve per unit. For peakers a summer heat rate profile is appropriate. For intermediate and baseload plants the average conditions are appropriate.
**Load Points:** Please provide as many as available.

*[TRADE SECRET DATA BEGINS…*

**VARIABLE O&M:**

**Variable O&M:** Typically chemicals and water only.
Strategist will use a inflation rate, based on non-labor rates to escalate this value.

**Ramp Rate:**
**Start Time:**

*…TRADE SECRET DATA ENDS]*

**Ramp Rate :** Strategist will use this input to calculate the units contribution to spinning reserve.
**Start Time:** This input used to determine quick start ability of unit.

**FIXED O&M:** *2013 dollars, $thousands*

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| | | | | | | | | | |

*…TRADE SECRET DATA ENDS]*

**Fixed O&M:** This cost should primarily be annual labor expenses. Strategist will use an inflation rate, based on labor rates to escalate this value.

**MAINTENANCE SCHEDULE** *Weeks / Year*

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| | | | | | | | | | |

*…TRADE SECRET DATA ENDS]*

*[TRADE SECRET DATA BEGINS…*

**FORCED OUTAGE RATE:**

**Maintenance Schedule:** This yearly profile should reflect periodic major outages.
**Forced Outage Rate:** A simple % that reflects the probability of unplanned outages.

**INITIAL CAPITAL COSTS:**

*…TRADE SECRET DATA ENDS]*

$thousands

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| | | | | | | | | | |

*…TRADE SECRET DATA ENDS]*

*Capital Notes: estimate in nominal dollars to COD in March 2017*

**Initial Capital:** Capital costs should include everything "inside the fence". Transmission costs should include interconnection but not other grid upgrades (these will be provided by Transmission). Gas costs should include interconnection but not additional pipeline upgrades that will be paid by either Xcel's gas operations or another gas company.

**ON-GOING CAPITAL COST!**

*2013 dollars, $thousands, or % of initial capital*

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|---|---|
| ***[TRADE SECRET DATA BEGINS…*** | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | ***…TRADE SECRET DATA ENDS]*** |

*On-Going Capital Notes: 2013 Dollars; escalation should be applied at approved Corporate rates*

**On-Going Capital:** Annual capital expenditures for regular maintenance and overhauls.

**Emissions Data :**

Average Emission Rates
lbs/mmBtu

lbs/mmBtu

***[TRADE SECRET DATA BEGINS…***

| | |
|---|---|
| SOx | |
| NOx | |
| CO2 | |
| HG | |
| PM_10 | |
| CO | |
| VOC | |
| Pb | |

***…TRADE SECRET DATA ENDS]***

**Emissions Data:** Data should reflect average emission rates stated in lbs/mmBtu using the units primary fuel. If lbs/mmbtu is not available Strategist does have the ability to model emissions as lbs/MWh.

**Based on full load data**

**Water Usage**

Average Water Consumption
gallons/MWh

gallons/MWh

***[TRADE SECRET DATA BEGINS…***

| | |
|---|---|
| Water Consumption | |

***…TRADE SECRET DATA ENDS]***

**Water Consumption:** Data should reflect average water consumption per MWh.

SOx, NOx,CO2, and Hg inputs are manditory for all OpCos

# Strategist Assumptions Documentation - *Transmission Project/Grid Upgrades*

**PROJECT:** Black Dog Unit 6 CT (2017)

**PREPARED BY:** *Greg Ford/Elizabeth Karels*
*4/8/2013*

**PROJECT DESCRIPTION AND SOURCE DOCUMENTATION:**

*[TRADE SECRET DATA BEGINS…*

*…TRADE SECRET ENDS]*

## PROJECT INFORMATION

**IN-SERVICE:** *3/1/2017*

**In-service:** Strategist will assume in-service at the 1st of the month.

*[TRADE SECRET DATA BEGINS…*

**NET CAPACITY :**

| | Summer | Average | Winter |
|---|---|---|---|
| Maximum Capacity | | | |
| Maximum With Ducts | | | |
| Emergency Capacity | | | |

*…TRADE SECRET DATA ENDS]*

**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:** Maximum with duct firing
**Emergency Capacity:** This input is commonly used for coal plants with "gas topping".

*[TRADE SECRET DATA BEGINS…*

**EXPECTED CAPACITY FACTOR**

**Expected Capacity Factor:** Based on Strategist simulations.

**INITIAL CAPITAL COSTS:**

*…TRADE SECRET DATA ENDS]*

*$thousands*

*[TRADE SECRET DATA BEGINS…*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*…TRADE SECRET DATA ENDS]*

*Capital Notes: Nominal Dollars*

**Grid Upgrade Costs:** The capital costs for additional grid upgrades needed to support the incremental generation of this project.

**ON-GOING ANNUAL EXPENSES:**

*2013 dollars, $thousands, or % of initial capital*

*[TRADE SECRET DATA BEGINS…*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*…TRADE SECRET DATA ENDS]*

*On-Going Expenses Notes:*

**On-Going Costs:** Annual cost for maintenance of proposed transmission infrastructure.

# Strategist Assumptions Documentation - *Gas Supply*

**PROJECT:** Black Dog Unit 6 CT (2017)

**PREPARED BY:** *Richard Derryberry*
*2/5/2013*

**PROJECT DESCRIPTION AND SOURCE DOCUMENTATION:**

*[TRADE SECRET DATA BEGINS…*

*…TRADE SECRET ENDS]*

**PROJECT INFORMATION:** *if additional project data is needed please contact Resource Planning Analytics*

**IN-SERVICE:** *3/1/2017*

**In-service:** Strategist will assume in-service at the 1st of the month.

**NET CAPACITY :**

*[TRADE SECRET DATA BEGINS…*

| | Summer | Average | Winter |
|---|---|---|---|
| Maximum Capacity | | | |
| Maximum With Ducts | | | |

*…TRADE SECRET DATA ENDS]*

**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:** Maximum with duct firing

**HEAT RATE:**

*[TRADE SECRET DATA BEGINS…*

| | Average |
|---|---|
| Maximum Capacity | |
| Maximum With Ducts | |

*…TRADE SECRET DATA ENDS]*

**Expected Heat Rate:** This value multiplied by the maximum capacity equals the peak fuel consumption (mmbtu/hour)

**EXPECTED CAPACITY FACTOR**

*[TRADE SECRET DATA BEGINS…*

*…TRADE SECRET DATA ENDS]*

**Expected Capacity Factor:** Based on Strategist simulations.

**ANNUAL FIXED FUEL CHARGE** *2013 dollars, $thousands*

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | |

*...TRADE SECRET DATA ENDS]*

*Fixed Charge Notes:*

**Annual Fixed Charge:** Annual cost that do not vary by volume of gas burned in a given year.

**VOLUMETRIC CHARGE:** *2013 dollars, $/mmbtu*

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|---|---|---|
| Supply Point | NNG | NNG | NNG | NNG | NNG | NNG | NNG | NNG | NNG | NNG |
| | *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| Fuel % | | | | | | | | | | |
| Variable - $/Dth | | | | | | | | | | |
| Variable - $/Dth | | | | | | | | | | |

*...TRADE SECRET DATA ENDS]*

*Volumetric Charge Notes:*

**Volumetric Charge:** The cost to deliver fuel to the unit from a priced distribution hub ( Ventura, CGI, Henry, etc). Please be sure to note the hub used in calculating this value.

# Strategist Assumptions Documentation - *Capital Asset Accounting*

**PROJECT:** Black Dog Unit 6 CT (2017)

**PREPARED BY:** *Elizabeth Karels*
*3/6/2013*

## PROJECT INFORMATION

**IN-SERVICE:** *3/1/2017*

**In-service:** Strategist will assume in-service at the 1st of the month.

**UNIT TYPE** *Combustion Turbine*

| | | Summer | Average | Winter |
|---|---|---|---|---|
| | | *[TRADE SECRET DATA BEGINS…* | | |
| **NET CAPACITY :** | Maximum Capacity | | | |
| | | | | *…TRADE SECRET DATA ENDS]* |

*[TRADE SECRET DATA BEGINS…*

**EXPECTED CAPACITY FACTOR**

*…TRADE SECRET DATA ENDS]*

**Expected Capacity Factor:** Based on Strategist simulations.

**NEW UNIT CAPITAL COSTS** *$thousands,*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *…TRADE SECRET DATA ENDS]* |

*Capital Notes:*

**Initial Capital:** Capital costs should include everything "inside the fence".

**ON-GOING CAPITAL COSTS** *2013 dollars, $thousands, or % of initial capital*

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *…TRADE SECRET DATA ENDS]* |

*On-Going Capital Notes:*

**On-Going Capital:** Annual capital expenditures for regular maintenance and overhauls.

**TRANSMISSION CAPITAL COSTS:** *2013 dollars, $thousands, or % of initial capital*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *…TRADE SECRET DATA ENDS]* |

*Transmission Capital Notes:*

**Grid Upgrade Costs:** The cost of additional grid upgrades needed to support the incremental generation of this project.

**UNIT DEPRECIATION:** *[TRADE SECRET DATA BEGINS…*

| | |
|---|---|
| BOOK LIFE | |
| BOOK DEPRECIATION | |
| TAX LIFE | |
| TAX DEPRECIATION | |

**DECOMMISSIONING EXPENSE:**

**TRANSMISSION INVESTMENT DEPRECIATION:**

| | |
|---|---|
| BOOK LIFE | |
| BOOK DEPRECIATION | |
| TAX LIFE | |
| TAX DEPRECIATION | |

**OTHER CAPITAL RELATED INPUTS**

**AFUDC / CWIP:**

**AFUDC / CWIP:** This input should be coordinated with Rates and Resource Planning

**PROPERTY TAX RATE:**

**PROPERTY TAXES :** Property Tax inputs should be coordinated with Tax Services

*…TRADE SECRET DATA ENDS]*

# Strategist Assumptions Documentation - *Unit Performance & Cost Estimate*

**PROJECT:** Black Dog Unit 6 CT (2018)

**PREPARED BY:** *Greg Ford/Elizabeth Karels*
*4/8/2013*

**PROJECT/UNIT DESCRIPTION AND SOURCE DOCUMENTATION:**
*[TRADE SECRET DATA BEGINS...*

*...TRADE SECRET ENDS]*

**IN-SERVICE DATE:** *3/1/2018*
**RETIREMENT DATE:** *12/31/2052*

**In-service:** Strategist will assume in-service at the 1st of the month.
**Retirement:** Strategist will assume retirement on the last day of the month.

**NET CAPACITY :**

| | | Summer | Average | Winter |
|---|---|---|---|---|
| Ambient Conditions Assumptions | | *95F* | 59 F | -5 F |
| | | *[TRADE SECRET DATA BEGINS...* | | |
| Minimum Capacity | (50%) | | | |
| Load Point 2 | (60%) | | | |
| Load Point 3 | (70%) | | | |
| Load Point 4 | (80%) | | | |
| Load Point 5 | (90%) | | | |
| Maximum Capacity | (100%) | | | |
| | | *...TRADE SECRET DATA ENDS]* | | |

**Minimum Capacity**: For a combined cycle unit it should be the minimum generation in combined cycle configuration. Not CT only using bypass stacks.
**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:**
**Emergency Capacity:** Strategist will not dispatch a unit at this level, but the unit will be accredited this capacity for loads and resource calculations. This input is commonly used for coal plants with "gas topping".

**HEAT RATE:**

*[TRADE SECRET DATA BEGINS...*

| | | Average |
|---|---|---|
| Minimum Capacity | (50%) | |
| Load Point 2 | (60%) | |
| Load Point 3 | (70%) | |
| Load Point 4 | (80%) | |
| Load Point 5 | (90%) | |
| Maximum Capacity | (100%) | |
| Maximum With Ducts | | |

*...TRADE SECRET DATA ENDS]*

**Heat Rate:** Strategist can only model a single heat rate curve per unit. For peakers a summer heat rate profile is appropriate. For intermediate and baseload plants the average conditions are appropriate.
**Load Points:** Please provide as many as available.

*[TRADE SECRET DATA BEGINS...*
**VARIABLE O&M:**

**Variable O&M:** Typically chemicals and water only.
Strategist will use a inflation rate, based on non-labor rates to escalate this value.

**Ramp Rate:**
**Start Time:**
*...TRADE SECRET DATA ENDS]*

**Ramp Rate :** Strategist will use this input to calculate the units contribution to spinning reserve.
**Start Time:** This input used to determine quick start ability of unit.

**FIXED O&M:** *2013 dollars, $thousands*

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS...* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *...TRADE SECRET DATA ENDS]* |

**Fixed O&M:** This cost should primarily be annual labor expenses. Strategist will use an inflation rate, based on labor rates to escalate this value.

**MAINTENANCE SCHEDULE** *Weeks / Year*

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS...* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *...TRADE SECRET DATA ENDS]* |

*[TRADE SECRET DATA BEGINS...*
**FORCED OUTAGE RATE:**

**Maintenance Schedule:** This yearly profile should reflect periodic major outages.
**Forced Outage Rate:** A simple % that reflects the probability of unplanned outages.

**INITIAL CAPITAL COSTS:**
*...TRADE SECRET DATA ENDS]*
$thousands

*Capital Notes: estimate in nominal dollars to COD in March 2017*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS...* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *...TRADE SECRET DATA ENDS]* |

**Initial Capital:** Capital costs should include everything "inside the fence". Transmission costs should include interconnection but not other grid upgrades (these will be provided by Transmission). Gas costs should include interconnection but not additional pipeline upgrades that will be paid by either Xcel's gas operations or another gas company.

| | | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ***[TRADE SECRET DATA BEGINS…*** | | | | | | | | | |
| **ON-GOING CAPITAL COSTS** | *2013 dollars, $thousands, or % of initial capital* | | | | | | | | | | |
| | | | | | | | | | | | ***…TRADE SECRET DATA ENDS]*** |

*On-Going Capital Notes: 2013 Dollars; escalation should be applied at approved Corporate rates*

**On-Going Capital:** Annual capital expenditures for regular maintenance and overhauls.

**Emissions Data :**

lbs/mmBtu

Average Emission Rates lbs/mmBtu

***[TRADE SECRET DATA BEGINS…***

| | |
|---|---|
| SOx | |
| NOx | |
| CO2 | |
| HG | |
| PM_10 | |
| CO | |
| VOC | |
| Pb | |

***…TRADE SECRET DATA ENDS]***

**Emissions Data:** Data should reflect average emission rates stated in lbs/mmBtu using the units primary fuel. If lbs/mmbtu is not available Strategist does have the ability to model emissions as lbs/MWh.

**Based on full load data**

**Water Usage**

gallons/MWh

Average Water Consumption gallons/MWh

***[TRADE SECRET DATA BEGINS…***

| | |
|---|---|
| Water Consumption | |

***…TRADE SECRET DATA ENDS]***

**Water Consumption:** Data should reflect average water consumption per MWh.

SOx, NOx,CO2, and Hg inputs are manditory for all OpCos

# Strategist Assumptions Documentation - *Transmission Project/Grid Upgrades*

**PROJECT:** **Black Dog Unit 6 CT (2018)**

**PREPARED BY:** *Greg Ford/Elizabeth Karels*
*4/8/2013*

**PROJECT DESCRIPTION AND SOURCE DOCUMENTATION:**

*[TRADE SECRET DATA BEGINS...*

*...TRADE SECRET ENDS]*

## PROJECT INFORMATION

**IN-SERVICE:** *3/1/2018*

**In-service:** Strategist will assume in-service at the 1st of the month.

*[TRADE SECRET DATA BEGINS...*

**NET CAPACITY :**

| | Summer | Average | Winter |
|---|---|---|---|
| Maximum Capacity | | | |
| Maximum With Ducts | | | |
| Emergency Capacity | | | |

*...TRADE SECRET DATA ENDS]*

**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:** Maximum with duct firing
**Emergency Capacity:** This input is commonly used for coal plants with "gas topping".

*[TRADE SECRET DATA BEGINS...*

**EXPECTED CAPACITY FACTOR**

**Expected Capacity Factor:** Based on Strategist simulations.

**INITIAL CAPITAL COSTS:**

*...TRADE SECRET DATA ENDS]*

*$thousands*

*[TRADE SECRET DATA BEGINS...*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*...TRADE SECRET DATA ENDS]*

*Capital Notes: Nominal Dollars*

**Grid Upgrade Costs:** The capital costs for additional grid upgrades needed to support the incremental generation of this project.

**ON-GOING ANNUAL EXPENSES:**

*2013 dollars, $thousands, or % of initial capital*

*[TRADE SECRET DATA BEGINS...*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*...TRADE SECRET DATA ENDS]*

*On-Going Expenses Notes:*

**On-Going Costs:** Annual cost for maintenance of proposed transmission infrastructure.

# Strategist Assumptions Documentation - *Gas Supply*

**PROJECT:** Black Dog Unit 6 CT (2018)

**PREPARED BY:** *Richard Derryberry*
*2/5/2013*

**PROJECT DESCRIPTION AND SOURCE DOCUMENTATION:**

*[TRADE SECRET DATA BEGINS…*

*…TRADE SECRET ENDS]*

**PROJECT INFORMATION:** *if additional project data is needed please contact Resource Planning Analytics*

**IN-SERVICE:** *3/1/2018*

**In-service:** Strategist will assume in-service at the 1st of the month.

**NET CAPACITY :**

*[TRADE SECRET DATA BEGINS…*

| | Summer | Average | Winter |
|---|---|---|---|
| Maximum Capacity | | | |
| Maximum With Ducts | | | |

*…TRADE SECRET DATA ENDS]*

**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:** Maximum with duct firing

**HEAT RATE:**

*[TRADE SECRET DATA BEGINS…*

| | Average |
|---|---|
| Maximum Capacity | |
| Maximum With Ducts | |

*…TRADE SECRET DATA ENDS]*

**Expected Heat Rate:** This value multiplied by the maximum capacity equals the peak fuel consumption (mmbtu/hour)

*[TRADE SECRET DATA BEGINS…*

**EXPECTED CAPACITY FACTOR**

*…TRADE SECRET DATA ENDS]*

**Expected Capacity Factor:** Based on Strategist simulations.

**ANNUAL FIXED FUEL CHARGE** *2013 dollars, $thousands*

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | |

*…TRADE SECRET DATA ENDS]*

*Fixed Charge Notes:*

**Annual Fixed Charge:** Annual cost that do not vary by volume of gas burned in a given year.

**VOLUMETRIC CHARGE:** *2013 dollars, $/mmbtu*

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| Supply Point | NNG | NNG | NNG | NNG | NNG | NNG | NNG | NNG | NNG | NNG |
| | *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| Fuel % | | | | | | | | | | |
| Variable - $/Dth | | | | | | | | | | |
| Variable - $/Dth | | | | | | | | | | |

*…TRADE SECRET DATA ENDS]*

*Volumetric Charge Notes:*

**Volumetric Charge:** The cost to deliver fuel to the unit from a priced distribution hub ( Ventura, CGI, Henry, etc). Please be sure to note the hub used in calculating this value.

# Strategist Assumptions Documentation - *Capital Asset Accounting*

**PROJECT:** Black Dog Unit 6 CT (2018)

**PREPARED BY:** *Elizabeth Karels*
*3/6/2013*

## PROJECT INFORMATION

**IN-SERVICE:** *3/1/2018*

**In-service:** Strategist will assume in-service at the 1st of the month.

**UNIT TYPE** *Combustion Turbine*

Summer Average Winter
*[TRADE SECRET DATA BEGINS…*

**NET CAPACITY :** Maximum Capacity

*[TRADE SECRET DATA BEGINS…* *…TRADE SECRET DATA ENDS]*

**EXPECTED CAPACITY FACTOR**

**Expected Capacity Factor:** Based on Strategist simulations.

*…TRADE SECRET DATA ENDS]*

**NEW UNIT CAPITAL COSTS** *$thousands,*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*[TRADE SECRET DATA BEGINS…* *…TRADE SECRET DATA ENDS]*

*Capital Notes:*

**Initial Capital:** Capital costs should include everything "inside the fence".

**ON-GOING CAPITAL COSTS** *2013 dollars, $thousands, or % of initial capital*

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*[TRADE SECRET DATA BEGINS…* *…TRADE SECRET DATA ENDS]*

*On-Going Capital Notes:*

**On-Going Capital:** Annual capital expenditures for regular maintenance and overhauls.

**TRANSMISSION CAPITAL COSTS:** *2013 dollars, $thousands, or % of initial capital*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*[TRADE SECRET DATA BEGINS…* *…TRADE SECRET DATA ENDS]*

*Transmission Capital Notes:*

**Grid Upgrade Costs:** The cost of additional grid upgrades needed to support the incremental generation of this project.

**UNIT DEPRECIATION:** *[TRADE SECRET DATA BEGINS…*
- BOOK LIFE
- BOOK DEPRECIATION
- TAX LIFE
- TAX DEPRECIATION

**DECOMMISSIONING EXPENSE:**

**TRANSMISSION INVESTMENT DEPRECIATION:**
- BOOK LIFE
- BOOK DEPRECIATION
- TAX LIFE
- TAX DEPRECIATION

**OTHER CAPITAL RELATED INPUTS**

**AFUDC / CWIP:**

**AFUDC / CWIP:** This input should be coordinated with Rates and Resource Planning

**PROPERTY TAX RATE:**

**PROPERTY TAXES :** Property Tax inputs should be coordinated with Tax Services

*…TRADE SECRET DATA ENDS]*

# Strategist Assumptions Documentation - *Unit Performance & Cost Estimate*

**PROJECT:** Black Dog Unit 6 CT (2019)

**PREPARED BY:** *Greg Ford/Elizabeth Karels*
*4/9/2013*

**PROJECT/UNIT DESCRIPTION AND SOURCE DOCUMENTATION:**

*[TRADE SECRET DATA BEGINS...*

*...TRADE SECRET ENDS]*

**IN-SERVICE DATE:** *3/1/2019*
**RETIREMENT DATE:** *12/31/2053*

**In-service:** Strategist will assume in-service at the 1st of the month.
**Retirement:** Strategist will assume retirement on the last day of the month.

**NET CAPACITY :**

| | | Summer | Average | Winter |
|---|---|---|---|---|
| Ambient Conditions Assumptions | | *95F* | 59 F | -5 F |
| | | *[TRADE SECRET DATA BEGINS...* | | |
| Minimum Capacity | (50%) | | | |
| Load Point 2 | (60%) | | | |
| Load Point 3 | (70%) | | | |
| Load Point 4 | (80%) | | | |
| Load Point 5 | (90%) | | | |
| Maximum Capacity | (100%) | | | |
| | | *...TRADE SECRET DATA ENDS]* | | |

**Minimum Capacity**: For a combined cycle unit it should be the minimum generation in combined cycle configuration. Not CT only using bypass stacks.
**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:**
**Emergency Capacity:** Strategist will not dispatch a unit at this level, but the unit will be accredited this capacity for loads and resource calculations. This input is commonly used for coal plants with "gas topping".

**HEAT RATE:**

*[TRADE SECRET DATA BEGINS...*

| | | Average |
|---|---|---|
| Minimum Capacity | (50%) | |
| Load Point 2 | (60%) | |
| Load Point 3 | (70%) | |
| Load Point 4 | (80%) | |
| Load Point 5 | (90%) | |
| Maximum Capacity | (100%) | |
| Maximum With Ducts | | |

*...TRADE SECRET DATA ENDS]*

**Heat Rate:** Strategist can only model a single heat rate curve per unit. For peakers a summer heat rate profile is appropriate. For intermediate and baseload plants the average conditions are appropriate.
**Load Points:** Please provide as many as available.

*[TRADE SECRET DATA BEGINS...*

**VARIABLE O&M:**

**Variable O&M:** Typically chemicals and water only.
Strategist will use a inflation rate, based on non-labor rates to escalate this value.

**Ramp Rate:**
**Start Time:**

*...TRADE SECRET DATA ENDS]*

**Ramp Rate :** Strategist will use this input to calculate the units contribution to spinning reserve.
**Start Time:** This input used to determine quick start ability of unit.

**FIXED O&M:** *2013 dollars, $thousands*

| 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS...* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *...TRADE SECRET DATA ENDS]* |

**Fixed O&M:** This cost should primarily be annual labor expenses. Strategist will use an inflation rate, based on labor rates to escalate this value.

**MAINTENANCE SCHEDULE** *Weeks / Year*

| 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS...* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *...TRADE SECRET DATA ENDS]* |

*[TRADE SECRET DATA BEGINS...*

**FORCED OUTAGE RATE:**

**Maintenance Schedule:** This yearly profile should reflect periodic major outages.
**Forced Outage Rate:** A simple % that reflects the probability of unplanned outages.

**INITIAL CAPITAL COSTS:**

*...TRADE SECRET DATA ENDS]*
$thousands

*Capital Notes: estimate in nominal dollars to COD in March 2017*

| 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS...* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *...TRADE SECRET DATA ENDS]* |

**Initial Capital:** Capital costs should include everything "inside the fence". Transmission costs should include interconnection but not other grid upgrades (these will be provided by Transmission). Gas costs should include interconnection but not additional pipeline upgrades that will be paid by either Xcel's gas operations or another gas company.

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| | *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| **ON-GOING CAPITAL COST:** *2013 dollars, $thousands, or % of initial capital* | | | | | | | | | | |
| | | | | | | | | | | *…TRADE SECRET DATA ENDS]* |

*On-Going Capital Notes: 2013 Dollars; escalation should be applied at approved Corporate rates*

**On-Going Capital:** Annual capital expenditures for regular maintenance and overhauls.

**Emissions Data :**

Average Emission Rates lbs/mmBtu

lbs/mmBtu

| | |
|---|---|
| | *[TRADE SECRET DATA BEGINS…* |
| SOx | |
| NOx | |
| CO2 | |
| HG | |
| PM_10 | |
| CO | |
| VOC | |
| Pb | |
| | *…TRADE SECRET DATA ENDS]* |

**Emissions Data:** Data should reflect average emission rates stated in lbs/mmBtu using the units primary fuel. If lbs/mmbtu is not available Strategist does have the ability to model emissions as lbs/MWh.

**Based on full load data**

**Water Usage**

Average Water Consumption gallons/MWh

gallons/MWh

| | |
|---|---|
| | *[TRADE SECRET DATA BEGINS…* |
| Water Consumption | |
| | *…TRADE SECRET DATA ENDS]* |

**Water Consumption:** Data should reflect average water consumption per MWh.

SOx, NOx,CO2, and Hg inputs are manditory for all OpCos

# Strategist Assumptions Documentation - *Transmission Project/Grid Upgrades*

**PROJECT:** Black Dog Unit 6 CT (2019)

**PREPARED BY:** *Greg Ford/Elizabeth Karels*
*4/9/2013*

**PROJECT DESCRIPTION AND SOURCE DOCUMENTATION:**

*[TRADE SECRET DATA BEGINS...*

*...TRADE SECRET ENDS]*

## PROJECT INFORMATION

**IN-SERVICE:** *3/1/2019*

**In-service:** Strategist will assume in-service at the 1st of the month.

*[TRADE SECRET DATA BEGINS...*

**NET CAPACITY :**

| | Summer | Average | Winter |
|---|---|---|---|
| Maximum Capacity | | | |
| Maximum With Ducts | | | |
| Emergency Capacity | | | |

*...TRADE SECRET DATA ENDS]*

**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:** Maximum with duct firing
**Emergency Capacity:** This input is commonly used for coal plants with "gas topping".

*[TRADE SECRET DATA BEGINS...*

**EXPECTED CAPACITY FACTOR**

**Expected Capacity Factor:** Based on Strategist simulations.

**INITIAL CAPITAL COSTS:**

*...TRADE SECRET DATA ENDS]*

*$thousands*

*Capital Notes: Nominal Dollars*

*[TRADE SECRET DATA BEGINS...*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

***...TRADE SECRET DATA ENDS]***

**Grid Upgrade Costs:** The capital costs for additional grid upgrades needed to support the incremental generation of this project.

**ON-GOING ANNUAL EXPENSES:**

*2013 dollars, $thousands, or % of initial capital*

*On-Going Expenses Notes:*

*[TRADE SECRET DATA BEGINS...*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

***...TRADE SECRET DATA ENDS]***

**On-Going Costs:** Annual cost for maintenance of proposed transmission infrastructure.

# Strategist Assumptions Documentation - *Gas Supply*

**PROJECT:** Black Dog Unit 6 CT (2019)

**PREPARED BY:** *Richard Derryberry*
*2/5/2013*

**PROJECT DESCRIPTION AND SOURCE DOCUMENTATION:**
*[TRADE SECRET DATA BEGINS...*
*...TRADE SECRET ENDS]*

**PROJECT INFORMATION:** *if additional project data is needed please contact Resource Planning Analytics*

**IN-SERVICE:** *3/1/2019*

**In-service:** Strategist will assume in-service at the 1st of the month.

**NET CAPACITY :**

*[TRADE SECRET DATA BEGINS...*

| | Summer | Average | Winter |
|---|---|---|---|
| Maximum Capacity | | | |
| Maximum With Ducts | | | |

*...TRADE SECRET DATA ENDS]*

**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:** Maximum with duct firing

**HEAT RATE:**

*[TRADE SECRET DATA BEGINS...*

| | Average |
|---|---|
| Maximum Capacity | |
| Maximum With Ducts | |

*...TRADE SECRET DATA ENDS]*

**Expected Heat Rate:** This value multiplied by the maximum capacity equals the peak fuel consumption (mmbtu/hour)

**EXPECTED CAPACITY FACTOR**
*[TRADE SECRET DATA BEGINS...*
*...TRADE SECRET DATA ENDS]*

**Expected Capacity Factor:** Based on Strategist simulations.

**ANNUAL FIXED FUEL CHARGE** *2013 dollars, $thousands*

| 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|

*[TRADE SECRET DATA BEGINS...*
*...TRADE SECRET DATA ENDS]*

*Fixed Charge Notes:*

**Annual Fixed Charge:** Annual cost that do not vary by volume of gas burned in a given year.

**VOLUMETRIC CHARGE:** *2013 dollars, $/mmbtu*

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| Supply Point | NNG | NNG | NNG | NNG | NNG | NNG | NNG | NNG | NNG | NNG |

*[TRADE SECRET DATA BEGINS...*

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| Fuel % | | | | | | | | | | |
| Variable - $/Dth | | | | | | | | | | |
| Variable - $/Dth | | | | | | | | | | |

*...TRADE SECRET DATA ENDS]*

*Volumetric Charge Notes:*

**Volumetric Charge:** The cost to deliver fuel to the unit from a priced distribution hub ( Ventura, CGI, Henry, etc). Please be sure to note the hub used in calculating this value.

# Strategist Assumptions Documentation - *Capital Asset Accounting*

**PROJECT:** Black Dog Unit 6 CT (2019)

**PREPARED BY:** *Elizabeth Karels*
*3/6/2013*

**PROJECT INFORMATION**

**IN-SERVICE:** *3/1/2019*

**In-service:** Strategist will assume in-service at the 1st of the month.

**UNIT TYPE** *Combustion Turbine*

Summer Average Winter
*[TRADE SECRET DATA BEGINS...*

**NET CAPACITY :** Maximum Capacity

*[TRADE SECRET DATA BEGINS...* *...TRADE SECRET DATA ENDS]*

**EXPECTED CAPACITY FACTOR**

**Expected Capacity Factor:** Based on Strategist simulations.

*...TRADE SECRET DATA ENDS]*

**NEW UNIT CAPITAL COSTS**

*$thousands,*

| 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*[TRADE SECRET DATA BEGINS...* *...TRADE SECRET DATA ENDS]*

*Capital Notes:*

**Initial Capital:** Capital costs should include everything "inside the fence".

**ON-GOING CAPITAL COSTS**

*2013 dollars, $thousands, or % of initial capital*

| 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*[TRADE SECRET DATA BEGINS...* *...TRADE SECRET DATA ENDS]*

*On-Going Capital Notes:*

**On-Going Capital:** Annual capital expenditures for regular maintenance and overhauls.

**TRANSMISSION CAPITAL COSTS:**

*2013 dollars, $thousands, or % of initial capital*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*[TRADE SECRET DATA BEGINS...* *...TRADE SECRET DATA ENDS]*

*Transmission Capital Notes:*

**Grid Upgrade Costs:** The cost of additional grid upgrades needed to support the incremental generation of this project.

**UNIT DEPRECIATION:** *[TRADE SECRET DATA BEGINS...*
- BOOK LIFE
- BOOK DEPRECIATION
- TAX LIFE
- TAX DEPRECIATION

**DECOMMISSIONING EXPENSE:**

**TRANSMISSION INVESTMENT DEPRECIATION:**
- BOOK LIFE
- BOOK DEPRECIATION
- TAX LIFE
- TAX DEPRECIATION

**OTHER CAPITAL RELATED INPUTS**

**AFUDC / CWIP:**

**AFUDC / CWIP:** This input should be coordinated with Rates and Resource Planning

**PROPERTY TAX RATE:**

**PROPERTY TAXES :** Property Tax inputs should be coordinated with Tax Services

*...TRADE SECRET DATA ENDS]*

# Strategist Assumptions Documentation - *Unit Performance & Cost Estimate*

**PROJECT:** Hankinson 1 CT (2018)

**PREPARED BY:** *Greg Ford/Elizabeth Karels*
*4/9/2013*

**PROJECT/UNIT DESCRIPTION AND SOURCE DOCUMENTATION:**
*[TRADE SECRET DATA BEGINS…*

*…TRADE SECRET ENDS]*

**IN-SERVICE DATE:** *3/1/2018*
**RETIREMENT DATE:** *12/31/2052*

**In-service:** Strategist will assume in-service at the 1st of the month.
**Retirement:** Strategist will assume retirement on the last day of the month.

**NET CAPACITY :**

| | | Summer | Average | Winter |
|---|---|---|---|---|
| Ambient Conditions Assumptions | | *88F* | 41 F | -5 F |
| | | *[TRADE SECRET DATA BEGINS…* | | |
| Minimum Capacity | (50%) | | | |
| Load Point 2 | (60%) | | | |
| Load Point 3 | (70%) | | | |
| Load Point 4 | (80%) | | | |
| Load Point 5 | (90%) | | | |
| Maximum Capacity | (100%) | | | |
| | | *…TRADE SECRET DATA ENDS]* | | |

**Minimum Capacity**: For a combined cycle unit it should be the minimum generation in combined cycle configuration. Not CT only using bypass stacks.
**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:**
**Emergency Capacity:** Strategist will not dispatch a unit at this level, but the unit will be accredited this capacity for loads and resource calculations. This input is commonly used for coal plants with "gas topping".

**HEAT RATE:**

*[TRADE SECRET DATA BEGINS…*

| | | Average |
|---|---|---|
| Minimum Capacity | (50%) | |
| Load Point 2 | (60%) | |
| Load Point 3 | (70%) | |
| Load Point 4 | (80%) | |
| Load Point 5 | (90%) | |
| Maximum Capacity | (100%) | |
| Maximum With Ducts | | |

*…TRADE SECRET DATA ENDS]*

**Heat Rate:** Strategist can only model a single heat rate curve per unit. For peakers a summer heat rate profile is appropriate. For intermediate and baseload plants the average conditions are appropriate.
**Load Points:** Please provide as many as available.

*[TRADE SECRET DATA BEGINS…*
**VARIABLE O&M:**

**Variable O&M:** Typically chemicals and water only.
Strategist will use a inflation rate, based on non-labor rates to escalate this value.

**Ramp Rate:**
**Start Time:**
*…TRADE SECRET DATA ENDS]*

**Ramp Rate :** Strategist will use this input to calculate the units contribution to spinning reserve.
**Start Time:** This input used to determine quick start ability of unit.

**FIXED O&M:** *2013 dollars, $thousands*

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *…TRADE SECRET DATA ENDS]* |

**Fixed O&M:** This cost should primarily be annual labor expenses. Strategist will use an inflation rate, based on labor rates to escalate this value.

**MAINTENANCE SCHEDULE** *Weeks / Year*

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *…TRADE SECRET DATA ENDS]* |

*[TRADE SECRET DATA BEGINS…*
**FORCED OUTAGE RATE:**

**Maintenance Schedule:** This yearly profile should reflect periodic major outages.
**Forced Outage Rate:** A simple % that reflects the probability of unplanned outages.

**INITIAL CAPITAL COSTS:**
*…TRADE SECRET DATA ENDS]*
$thousands

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS…* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *…TRADE SECRET DATA ENDS]* |

*Capital Notes: estimate in nominal dollars to COD in March 2017*

**Initial Capital:** Capital costs should include everything "inside the fence". Transmission costs should include interconnection but not other grid upgrades (these will be provided by Transmission). Gas costs should include interconnection but not additional pipeline upgrades that will be paid by either Xcel's gas operations or another gas company.

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| | ***[TRADE SECRET DATA BEGINS…*** | | | | | | | | | |
| **ON-GOING CAPITAL COST:** *2013 dollars, $thousands, or % of initial capital* | | | | | | | | | | |
| | | | | | | | | | | ***…TRADE SECRET DATA ENDS]*** |

*On-Going Capital Notes: 2013 Dollars; escalation should be applied at approved Corporate rates*

**On-Going Capital:** Annual capital expenditures for regular maintenance and overhauls.

**Emissions Data** :

lbs/mmBtu

| | Average Emission Rates lbs/mmBtu |
|---|---|
| | ***[TRADE SECRET DATA BEGINS…*** |
| SOx | |
| NOx | |
| CO2 | |
| HG | |
| PM_10 | |
| CO | |
| VOC | |
| Pb | |
| | ***…TRADE SECRET DATA ENDS]*** |

**Emissions Data:** Data should reflect average emission rates stated in lbs/mmBtu using the units primary fuel. If lbs/mmbtu is not available Strategist does have the ability to model emissions as lbs/MWh.

**Based on full load data**

**Water Usage**

gallons/MWh

| | Average Water Consumption gallons/MWh |
|---|---|
| | ***[TRADE SECRET DATA BEGINS…*** |
| Water Consumption | |
| | ***…TRADE SECRET DATA ENDS]*** |

**Water Consumption:** Data should reflect average water consumption per MWh.

SOx, NOx,CO2, and Hg inputs are manditory for all OpCos

# Strategist Assumptions Documentation - *Transmission Project/Grid Upgrades*

**PROJECT:** Hankinson 1 CT (2018)

**PREPARED BY:** *Greg Ford/Elizabeth Karels*
*4/9/2013*

**PROJECT DESCRIPTION AND SOURCE DOCUMENTATION:**

*[TRADE SECRET DATA BEGINS...*

*...TRADE SECRET ENDS]*

## PROJECT INFORMATION

**IN-SERVICE:** *3/1/2018*

**In-service:** Strategist will assume in-service at the 1st of the month.

**NET CAPACITY :**

*[TRADE SECRET DATA BEGINS...*

| | Summer | Average | Winter |
|---|---|---|---|
| Maximum Capacity | | | |
| Maximum With Ducts | | | |
| Emergency Capacity | | | |

*...TRADE SECRET DATA ENDS]*

**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:** Maximum with duct firing
**Emergency Capacity:** This input is commonly used for coal plants with "gas topping".

*[TRADE SECRET DATA BEGINS...*

**EXPECTED CAPACITY FACTOR**

**Expected Capacity Factor:** Based on Strategist simulations.

**INITIAL CAPITAL COSTS:**

*...TRADE SECRET DATA ENDS]*
*$thousands*

*[TRADE SECRET DATA BEGINS...*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*...TRADE SECRET DATA ENDS]*

*Capital Notes: Nominal Dollars*

**Grid Upgrade Costs:** The capital costs for additional grid upgrades needed to support the incremental generation of this project.

**ON-GOING ANNUAL EXPENSES:**

*2013 dollars, $thousands, or % of initial capital*

*[TRADE SECRET DATA BEGINS...*

| year | year | year | year | year | year | year | year | year | year |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*...TRADE SECRET DATA ENDS]*

*On-Going Expenses Notes: No ongoing expenses expected.*

**On-Going Costs:** Annual cost for maintenance of proposed transmission infrastructure.

# Strategist Assumptions Documentation - *Gas Supply*

**PROJECT:** Hankinson 1 CT (2018)

**PREPARED BY:** *Richard Derryberry*
*4/4/2014*

**PROJECT DESCRIPTION AND SOURCE DOCUMENTATION:**
*[TRADE SECRET DATA BEGINS…*

*…TRADE SECRET ENDS]*

**PROJECT INFORMATION:** *if additional project data is needed please contact Resource Planning Analytics*

**IN-SERVICE:** *3/1/2018*

**In-service:** Strategist will assume in-service at the 1st of the month.

**NET CAPACITY :**

*[TRADE SECRET DATA BEGINS…*

| | Summer | Average | Winter |
|---|---|---|---|
| Maximum Capacity | | | |
| Maximum With Ducts | | | |

*…TRADE SECRET DATA ENDS]*

**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:** Maximum with duct firing

**HEAT RATE:**

*[TRADE SECRET DATA BEGINS…*

| | Average |
|---|---|
| Maximum Capacity | |
| Maximum With Ducts | |

*…TRADE SECRET DATA ENDS]*

**Expected Heat Rate:** This value multiplied by the maximum capacity equals the peak fuel consumption (mmbtu/hour). Please see Energy Supply data for additional capacity and heat rate data.

*[TRADE SECRET DATA BEGINS…*

**EXPECTED CAPACITY FACTOR**

**Expected Capacity Factor:** Based on Strategist simulations.

**INITIAL CAPITAL COSTS:**

*…TRADE SECRET DATA ENDS]*

*Capital Notes: Nominal dollars*

*[TRADE SECRET DATA BEGINS…*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*…TRADE SECRET DATA ENDS]*

**ANNUAL O&M COSTS**

*Nominal dollars*

*Notes: Minor annual O&M to maintain pipeline servicing facility.*

*[TRADE SECRET DATA BEGINS…*

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | |

*…TRADE SECRET DATA ENDS]*

**VOLUMETRIC CHARGE:**

*2013 dollars, $/mmbtu*

*[TRADE SECRET DATA BEGINS…*

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| Pricing Basis | | | | | | | | | | |

*…TRADE SECRET DATA ENDS]*

*Volumetric Charge Notes:*

**Volumetric Charge:**

# Strategist Assumptions Documentation - *Capital Asset Accounting*

**PROJECT:** Hankinson 1 CT (2018)

**PREPARED BY:** *Elizabeth Karels*
*3/7/2013*

**PROJECT INFORMATION**

**IN-SERVICE:** *3/1/2018*

**In-service:** Strategist will assume in-service at the 1st of the month.

**UNIT TYPE** *Combustion Turbine*

Summer Average Winter

*[TRADE SECRET DATA BEGINS...*

**NET CAPACITY :** Maximum Capacity

*[TRADE SECRET DATA BEGINS...* *...TRADE SECRET DATA ENDS]*

**EXPECTED CAPACITY FACTOR**

**Expected Capacity Factor:** Based on Strategist simulations.

*...TRADE SECRET DATA ENDS]*

**NEW UNIT CAPITAL COSTS** *$thousands,*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*[TRADE SECRET DATA BEGINS...* *...TRADE SECRET DATA ENDS]*

*Capital Notes:*

**Initial Capital:** Capital costs should include everything "inside the fence".

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*[TRADE SECRET DATA BEGINS...*

**ON-GOING CAPITAL COSTS** *2013 dollars, $thousands, or % of initial capital*

*...TRADE SECRET DATA ENDS]*

*On-Going Capital Notes:*

**On-Going Capital:** Annual capital expenditures for regular maintenance and overhauls.

**TRANSMISSION CAPITAL COSTS:** *2013 dollars, $thousands, or % of initial capital*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*[TRADE SECRET DATA BEGINS...* *...TRADE SECRET DATA ENDS]*

*Transmission Capital Notes:*

**Grid Upgrade Costs:** The cost of additional grid upgrades needed to support the incremental generation of this project.

**UNIT DEPRECIATION:** *[TRADE SECRET DATA BEGINS...*

BOOK LIFE
BOOK DEPRECIATION
TAX LIFE
TAX DEPRECIATION

**DECOMMISSIONING EXPENSE:**

**TRANSMISSION INVESTMENT DEPRECIATION:**

BOOK LIFE
BOOK DEPRECIATION
TAX LIFE
TAX DEPRECIATION

**OTHER CAPITAL RELATED INPUTS**

**AFUDC / CWIP:**

**AFUDC / CWIP:** This input should be coordinated with Rates and Resource Planning

**PROPERTY TAX RATE:**

**PROPERTY TAXES :** Property Tax inputs should be coordinated with Tax Services

*...TRADE SECRET DATA ENDS]*

# Strategist Assumptions Documentation - *Unit Performance & Cost Estimate*

**PROJECT:** Hankinson 2 CT (2019)

**PREPARED BY:** *Greg Ford/Elizabeth Karels*
*4/8/2013*

**PROJECT/UNIT DESCRIPTION AND SOURCE DOCUMENTATION:**
*[TRADE SECRET DATA BEGINS...*

*...TRADE SECRET ENDS]*

**IN-SERVICE DATE:** *2/1/2019*
**RETIREMENT DATE:** *12/31/2053*

**In-service:** Strategist will assume in-service at the 1st of the month.
**Retirement:** Strategist will assume retirement on the last day of the month.

**NET CAPACITY :**

| | | Summer | Average | Winter |
|---|---|---|---|---|
| Ambient Conditions Assumptions | | *88F* | 41 F | -5 F |
| | | *[TRADE SECRET DATA BEGINS...* | | |
| Minimum Capacity | (50%) | | | |
| Load Point 2 | (60%) | | | |
| Load Point 3 | (70%) | | | |
| Load Point 4 | (80%) | | | |
| Load Point 5 | (90%) | | | |
| Maximum Capacity | (100%) | | | |
| | | *...TRADE SECRET DATA ENDS]* | | |

**Minimum Capacity**: For a combined cycle unit it should be the minimum generation in combined cycle configuration. Not CT only using bypass stacks.
**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:**
**Emergency Capacity:** Strategist will not dispatch a unit at this level, but the unit will be accredited this capacity for loads and resource calculations. This input is commonly used for coal plants with "gas topping".

**HEAT RATE:**

*[TRADE SECRET DATA BEGINS...*

| | | Average |
|---|---|---|
| Minimum Capacity | (50%) | |
| Load Point 2 | (60%) | |
| Load Point 3 | (70%) | |
| Load Point 4 | (80%) | |
| Load Point 5 | (90%) | |
| Maximum Capacity | (100%) | |
| Maximum With Ducts | | |

*...TRADE SECRET DATA ENDS]*

**Heat Rate:** Strategist can only model a single heat rate curve per unit. For peakers a summer heat rate profile is appropriate. For intermediate and baseload plants the average conditions are appropriate.
**Load Points:** Please provide as many as available.

*[TRADE SECRET DATA BEGINS...*

**VARIABLE O&M:**

**Variable O&M:** Typically chemicals and water only.
Strategist will use a inflation rate, based on non-labor rates to escalate this value.

**Ramp Rate:**
**Start Time:**
*...TRADE SECRET DATA ENDS]*

**Ramp Rate :** Strategist will use this input to calculate the units contribution to spinning reserve.
**Start Time:** This input used to determine quick start ability of unit.

**FIXED O&M:** *2013 dollars, $thousands*

| 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS...* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *...TRADE SECRET DATA ENDS]* |

**Fixed O&M:** This cost should primarily be annual labor expenses. Strategist will use an inflation rate, based on labor rates to escalate this value.

**MAINTENANCE SCHEDULE** *Weeks / Year*

| 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS...* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *...TRADE SECRET DATA ENDS]* |

*[TRADE SECRET DATA BEGINS...*

**FORCED OUTAGE RATE:**

**Maintenance Schedule:** This yearly profile should reflect periodic major outages.
**Forced Outage Rate:** A simple % that reflects the probability of unplanned outages.

**INITIAL CAPITAL COSTS:**

*...TRADE SECRET DATA ENDS]*
$thousands

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| *[TRADE SECRET DATA BEGINS...* | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | *...TRADE SECRET DATA ENDS]* |

*Capital Notes: estimate in nominal dollars to COD in March 2017*

**Initial Capital:** Capital costs should include everything "inside the fence". Transmission costs should include interconnection but not other grid upgrades (these will be provided by Transmission). Gas costs should include interconnection but not additional pipeline upgrades that will be paid by either Xcel's gas operations or another gas company.

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| **ON-GOING CAPITAL COSTS** *2013 dollars, $thousands, or % of initial capital* | | | | | | | | | | |

*[TRADE SECRET DATA BEGINS…*

*…TRADE SECRET DATA ENDS]*

*On-Going Capital Notes: 2013 Dollars; escalation should be applied at approved Corporate rates*

**On-Going Capital:** Annual capital expenditures for regular maintenance and overhauls.

**Emissions Data :**

lbs/mmBtu

Average Emission Rates lbs/mmBtu

*[TRADE SECRET DATA BEGINS…*

| | |
|---|---|
| SOx | |
| NOx | |
| CO2 | |
| HG | |
| PM_10 | |
| CO | |
| VOC | |
| Pb | |

*…TRADE SECRET DATA ENDS]*

**Emissions Data:** Data should reflect average emission rates stated in lbs/mmBtu using the units primary fuel. If lbs/mmbtu is not available Strategist does have the ability to model emissions as lbs/MWh.

**Based on full load data**

**Water Usage**

gallons/MWh

Average Water Consumption gallons/MWh

*[TRADE SECRET DATA BEGINS…*

| | |
|---|---|
| Water Consumption | |

*…TRADE SECRET DATA ENDS]*

**Water Consumption:** Data should reflect average water consumption per MWh.

SOx, NOx,CO2, and Hg inputs are manditory for all OpCos

# Strategist Assumptions Documentation - *Transmission Project/Grid Upgrades*

**PROJECT:** **Hankinson 2 CT (2019)**

**PREPARED BY:** *Greg Ford/Elizabeth Karels*
*4/8/2013*

**PROJECT DESCRIPTION AND SOURCE DOCUMENTATION:**
***[TRADE SECRET DATA BEGINS...***

***...TRADE SECRET ENDS]***

## PROJECT INFORMATION

**IN-SERVICE:** *2/1/2019*

**In-service:** Strategist will assume in-service at the 1st of the month.

***[TRADE SECRET DATA BEGINS...***

**NET CAPACITY :**

| | Summer | Average | Winter |
|---|---|---|---|
| Maximum Capacity | | | |
| Maximum With Ducts | | | |
| Emergency Capacity | | | |

***...TRADE SECRET DATA ENDS]***

**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:** Maximum with duct firing
**Emergency Capacity:** This input is commonly used for coal plants with "gas topping".

***[TRADE SECRET DATA BEGINS...***

**EXPECTED CAPACITY FACTOR**

**Expected Capacity Factor:** Based on Strategist simulations.

**INITIAL CAPITAL COSTS:**

***...TRADE SECRET DATA ENDS]***
*$thousands*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

***[TRADE SECRET DATA BEGINS...*** ***...TRADE SECRET DATA ENDS]***

*Capital Notes: Nominal Dollars*

**Grid Upgrade Costs:** The capital costs for additional grid upgrades needed to support the incremental generation of this project.

**ON-GOING ANNUAL EXPENSES:**

*2013 dollars, $thousands, or % of initial capital*

| year | year | year | year | year | year | year | year | year | year |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

***[TRADE SECRET DATA BEGINS...*** ***...TRADE SECRET DATA ENDS]***

*On-Going Expenses Notes: No ongoing expenses expected.*

**On-Going Costs:** Annual cost for maintenance of proposed transmission infrastructure.

# Strategist Assumptions Documentation - *Gas Supply*

**PROJECT:** Hankinson 2 CT (2019)

**PREPARED BY:** *Richard Derryberry*
*4/4/2014*

**PROJECT DESCRIPTION AND SOURCE DOCUMENTATION:**

*[TRADE SECRET DATA BEGINS…*

*…TRADE SECRET ENDS]*

**PROJECT INFORMATION:** *if additional project data is needed please contact Resource Planning Analytics*

**IN-SERVICE:** *2/1/2019*

**In-service:** Strategist will assume in-service at the 1st of the month.

**NET CAPACITY :**

*[TRADE SECRET DATA BEGINS…*

| | Summer | Average | Winter |
|---|---|---|---|
| Maximum Capacity | | | |
| Maximum With Ducts | | | |

*…TRADE SECRET DATA ENDS]*

**Maximum Capacity:** Should be the maximum net generation without duct firing.
**Maximum With Ducts:** Maximum with duct firing

**HEAT RATE:**

*[TRADE SECRET DATA BEGINS…*

| | Average |
|---|---|
| Maximum Capacity | |
| Maximum With Ducts | |

*…TRADE SECRET DATA ENDS]*

**Expected Heat Rate:** This value multiplied by the maximum capacity equals the peak fuel consumption (mmbtu/hour). Please see Energy Supply data for additional capacity and heat rate data.

*[TRADE SECRET DATA BEGINS…*

**EXPECTED CAPACITY FACTOR**

**Expected Capacity Factor:** Based on Strategist simulations.

**INITIAL CAPITAL COSTS:**

*…TRADE SECRET DATA ENDS]*

*Capital Notes: Nominal dollars*

*[TRADE SECRET DATA BEGINS…*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*…TRADE SECRET DATA ENDS]*

**ANNUAL O&M COSTS** *Nominal dollars*

*Notes: Minor annual O&M to maintain pipeline servicing facility.*

*[TRADE SECRET DATA BEGINS…*

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | |

*…TRADE SECRET DATA ENDS]*

**VOLUMETRIC CHARGE:** *2013 dollars, $/mmbtu* Pricing Basis

*[TRADE SECRET DATA BEGINS…*

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

*…TRADE SECRET DATA ENDS]*

*Volumetric Charge Notes:*

**Volumetric Charge:**

# Strategist Assumptions Documentation - *Capital Asset Accounting*

**PROJECT:** Hankinson 2 CT (2019)

**PREPARED BY:** *Elizabeth Karels*
*3/7/2013*

**PROJECT INFORMATION**

**IN-SERVICE:** *2/1/2019*

**In-service:** Strategist will assume in-service at the 1st of the month.

**UNIT TYPE** *Combustion Turbine*

Summer Average Winter

*[TRADE SECRET DATA BEGINS…*

**NET CAPACITY :** Maximum Capacity

*[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]*

**EXPECTED CAPACITY FACTOR**

**Expected Capacity Factor:** Based on Strategist simulations.

*…TRADE SECRET DATA ENDS]*

**NEW UNIT CAPITAL COSTS** *$thousands,*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|

*[TRADE SECRET DATA BEGINS…*

*…TRADE SECRET DATA ENDS]*

*Capital Notes:*

**Initial Capital:** Capital costs should include everything "inside the fence".

| 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|

*[TRADE SECRET DATA BEGINS…*

**ON-GOING CAPITAL COSTS** *2013 dollars, $thousands, or % of initial capital*

*…TRADE SECRET DATA ENDS]*

*On-Going Capital Notes:*

**On-Going Capital:** Annual capital expenditures for regular maintenance and overhauls.

**TRANSMISSION CAPITAL COSTS:** *2013 dollars, $thousands, or % of initial capital*

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|

*[TRADE SECRET DATA BEGINS…*

*…TRADE SECRET DATA ENDS]*

*Transmission Capital Notes:*

**Grid Upgrade Costs:** The cost of additional grid upgrades needed to support the incremental generation of this project.

**UNIT DEPRECIATION:** *[TRADE SECRET DATA BEGINS…*

BOOK LIFE
BOOK DEPRECIATION
TAX LIFE
TAX DEPRECIATION

**DECOMMISSIONING EXPENSE:**

**TRANSMISSION INVESTMENT DEPRECIATION:**

BOOK LIFE
BOOK DEPRECIATION
TAX LIFE
TAX DEPRECIATION

**OTHER CAPITAL RELATED INPUTS**

**AFUDC / CWIP:**

**AFUDC / CWIP:** This input should be coordinated with Rates and Resource Planning

**PROPERTY TAX RATE:**

**PROPERTY TAXES :** Property Tax inputs should be coordinated with Tax Services

*…TRADE SECRET DATA ENDS]*

## Appendix D
## System Capacity Data

Applicant shall describe the ability of its existing system to meet the demand for electrical energy forecast in response to Minnesota Rules Chapter 7849.0270 and the extent to which the proposed facility will increase this capability.

*A. Brief discussion of power planning programs*

NSP engages in regular rounds of resource planning analysis. Though careful evaluation of customer demand and available resources the Company completes and assessment of future resource needs that is fully reviewed by regulatory bodies and other stakeholders. Our most recent resource plan cycle began in summer of 2010 and received final Commission approval in March 2013. The latest resource planning cycle used a reserve margin criteria of 3.8 percent applied to the company's peak summer demand.

## *B. Seasonal Firm Purchases and Sales*

**Seasonal Firm Purchases - Summer**

| | Omaha Public Power | Basin Electric Power | Great River Energy | Western Area Power Admin | Manitoba Hydro | Total |
|---|---|---|---|---|---|---|
| 2003 | 35 | 50 | 75 | 2 | 350 | 512 |
| 2004 | | 50 | 75 | 2 | 350 | 477 |
| 2005 | | 50 | 75 | 2 | 350 | 477 |
| 2006 | | 50 | 75 | 2 | 350 | 477 |
| 2007 | | | | 2 | 350 | 352 |
| 2008 | | | | 2 | 350 | 352 |
| 2009 | | | | 2 | 350 | 352 |
| 2010 | | | | 2 | 350 | 352 |
| 2011 | | | | 2 | 350 | 352 |
| 2012 | | | | 2 | 350 | 352 |
| **2013** | | | | 2 | 350 | 352 |
| 2014 | | | | 2 | 350 | 352 |
| 2015 | | | | 2 | 350 | 352 |
| 2016 | | | | 2 | 350 | 352 |
| 2017 | | | | 2 | 350 | 352 |
| 2018 | | | | 2 | 350 | 352 |
| 2019 | | | | 2 | 350 | 352 |
| 2020 | | | | 2 | 350 | 352 |
| 2021 | | | | | 350 | 350 |
| 2022 | | | | | 350 | 350 |
| 2023 | | | | | 350 | 350 |
| 2024 | | | | | 350 | 350 |
| 2025 | | | | | | |
| 2026 | | | | | | |
| 2027 | | | | | | |
| 2028 | | | | | | |

**Seasonal Firm Purchases - Winter**

| | Basin Electric Power | Great River Energy | Western Area Power Admin | Total |
|---|---|---|---|---|
| 2003 | 50 | 75 | 2 | 127 |
| 2004 | 50 | 75 | 2 | 127 |
| 2005 | 50 | 75 | 2 | 127 |
| 2006 | 50 | 75 | 2 | 127 |
| 2007 | | | 2 | 2 |
| 2008 | | | 2 | 2 |
| 2009 | | | 2 | 2 |
| 2010 | | | 2 | 2 |
| 2011 | | | 2 | 2 |
| 2012 | | | 2 | 2 |
| **2013** | | | 2 | 2 |
| 2014 | | | 2 | 2 |
| 2015 | | | 2 | 2 |
| 2016 | | | 2 | 2 |
| 2017 | | | 2 | 2 |
| 2018 | | | 2 | 2 |
| 2019 | | | 2 | 2 |
| 2020 | | | 2 | 2 |
| 2021 | | | | |
| 2022 | | | | |
| 2023 | | | | |
| 2024 | | | | |
| 2025 | | | | |
| 2026 | | | | |
| 2027 | | | | |
| 2028 | | | | |

## Seasonal Firm Sales - Summer

| | Various Small Municipal Power Agencies | Total |
|---|---|---|
| 2003 | 15 | 15 |
| 2004 | 15 | 15 |
| 2005 | | |
| 2006 | | |
| 2007 | | |
| 2008 | | |
| 2009 | | |
| 2010 | | |
| 2011 | | |
| 2012 | | |
| **2013** | | |
| 2014 | | |
| 2015 | | |
| 2016 | | |
| 2017 | | |
| 2018 | | |
| 2019 | | |
| 2020 | | |
| 2021 | | |
| 2022 | | |
| 2023 | | |
| 2024 | | |
| 2025 | | |
| 2026 | | |
| 2027 | | |
| 2028 | | |

## Seasonal Firm Sales - Winter

| | Various Small Municipal Power Agencies | Manitoba Hydro | Total |
|---|---|---|---|
| 2003 | 15 | 350 | 365 |
| 2004 | 15 | 350 | 365 |
| 2005 | 16 | 350 | 366 |
| 2006 | 15 | 350 | 365 |
| 2007 | | 350 | 350 |
| 2008 | | 350 | 350 |
| 2009 | | 350 | 350 |
| 2010 | | 350 | 350 |
| 2011 | | 350 | 350 |
| 2012 | | 350 | 350 |
| **2013** | | 350 | 350 |
| 2014 | | 350 | 350 |
| 2015 | | 350 | 350 |
| 2016 | | 350 | 350 |
| 2017 | | 350 | 350 |
| 2018 | | 350 | 350 |
| 2019 | | 350 | 350 |
| 2020 | | 350 | 350 |
| 2021 | | 350 | 350 |
| 2022 | | 350 | 350 |
| 2023 | | 350 | 350 |
| 2024 | | 350 | 350 |
| 2025 | | | |
| 2026 | | | |
| 2027 | | | |
| 2028 | | | |

## *C. Seasonal Participation Purchases and Sales*

**Seasonal Participation Purchases - Summer**

| | Ameren | Calpine | CMMPA | Constellation | Coyote | Cyprus | Detroit Edison | Dynegy | Exelon | Fibrominn | GenSys | GRE | Hutchinson | Invenergy | Laurentian | LS Power | Manitoba Hydro | MidAmerican | MN Power | Minnkota | MN Municipal Power |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 255 | | 25 | | 100 | | | 100 | | | | | | | | | 760 | 150 | 100 | | |
| 2004 | 235 | | 25 | | 100 | | | 100 | | | 50 | | | | | | 960 | 150 | 100 | | |
| 2005 | | | 25 | 100 | 100 | | | 158 | | | 70 | | | | | | 700 | | 100 | | 130 |
| 2006 | | 312 | | 62 | 100 | 40 | 69 | 408 | 125 | | | | | | | 245 | 713 | | 100 | 100 | |
| 2007 | 100 | 312 | | 285 | 100 | 40 | | 658 | | 50 | | 160 | 20 | | 35 | 245 | 500 | | 100 | 100 | 10 |
| 2008 | | 312 | | 90 | 100 | 40 | | 258 | | 50 | | | | 301 | 35 | 245 | 713 | | | 100 | 10 |
| 2009 | | 312 | | 95 | 100 | 40 | | | | 50 | | | | 301 | 35 | 245 | 713 | | | 100 | 10 |
| 2010 | | 312 | | 100 | 100 | 40 | | | | 50 | | | | 301 | 35 | 245 | 500 | | | 100 | 10 |
| 2011 | | 312 | | | 100 | 40 | | | | 50 | | | | 301 | 35 | 245 | 500 | | | 100 | |
| 2012 | | 312 | | | 100 | 40 | | | | 50 | | | | 301 | 35 | 245 | 500 | | | 100 | |
| **2013** | | 312 | | | 100 | 40 | | | | 50 | | | | 301 | 35 | 245 | 500 | | | 100 | |
| 2014 | | 312 | | | 100 | | | | | 50 | | | | 301 | 35 | 245 | 500 | | | 100 | |
| 2015 | | 312 | | | 100 | | | | | 50 | | | | 301 | 35 | 245 | 375 | | | 100 | |
| 2016 | | 312 | | | | | | | | 50 | | | | 301 | 35 | 245 | 375 | | | | |
| 2017 | | 312 | | | | | | | | 50 | | | | 301 | 35 | 245 | 375 | | | | |
| 2018 | | 312 | | | | | | | | 50 | | | | 301 | 35 | 245 | 375 | | | | |
| 2019 | | 312 | | | | | | | | 50 | | | | 301 | 35 | 245 | 375 | | | | |
| 2020 | | 312 | | | | | | | | 50 | | | | 301 | 35 | 245 | 375 | | | | |
| 2021 | | 312 | | | | | | | | 50 | | | | 301 | 35 | 245 | 500 | | | | |
| 2022 | | 312 | | | | | | | | 50 | | | | 301 | 35 | 245 | 500 | | | | |
| 2023 | | 312 | | | | | | | | 50 | | | | 301 | 35 | 245 | 500 | | | | |
| 2024 | | 312 | | | | | | | | 50 | | | | 301 | 35 | 245 | 500 | | | | |
| 2025 | | 312 | | | | | | | | 50 | | | | | 35 | 245 | | | | | |
| 2026 | | | | | | | | | | 50 | | | | | 35 | 245 | | | | | |
| 2027 | | | | | | | | | | 50 | | | | | | 245 | | | | | |
| 2028 | | | | | | | | | | 50 | | | | | | | | | | | |

**Seasonal Participation Purchases - Summer**

| | Non-Utility Group | Omaha Public Power | Otter Tail Power | Short Term | Split Rock | St. Paul Co-gen | The Energy Authority | United Power Associates | Western Resources | Wind (Accredited Capacity) | Wisconsin Public Service | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 381 | 10 | 75 | | | | | 50 | 61 | 46 | | 4116 |
| 2004 | 381 | | 75 | | 100 | | | 50 | | 65 | | 4395 |
| 2005 | 381 | | 50 | | | | | 50 | | 71 | 200 | 4140 |
| 2006 | 85 | | | | 200 | 25 | | 50 | | 92 | 50 | 4782 |
| 2007 | 85 | | | | | 25 | | 50 | | 122 | | 5004 |
| 2008 | 85 | | | 642 | | 25 | | 50 | | 168 | | 5232 |
| 2009 | 85 | | | 165 | | 25 | | 50 | | 178 | | 4513 |
| 2010 | 85 | | | 265 | | 25 | 20 | 50 | | 207 | | 4455 |
| 2011 | 85 | | | | | 25 | | | | 224 | | 4028 |
| 2012 | 85 | | | | | 25 | | | | 254 | | 4059 |
| **2013** | 85 | | | | | 25 | | | | 254 | | 4060 |
| 2014 | 82 | | | | | 25 | | | | 254 | | 4018 |
| 2015 | 82 | | | | | 25 | | | | 254 | | 3894 |
| 2016 | 82 | | | | | 25 | | | | 254 | | 3695 |
| 2017 | 79 | | | | | 25 | | | | 254 | | 3693 |
| 2018 | 45 | | | | | 25 | | | | 254 | | 3660 |
| 2019 | 45 | | | | | 25 | | | | 254 | | 3661 |
| 2020 | 40 | | | | | 25 | | | | 254 | | 3657 |
| 2021 | 40 | | | | | 25 | | | | 254 | | 3783 |
| 2022 | 30 | | | | | 25 | | | | 254 | | 3774 |
| 2023 | 30 | | | | | 25 | | | | 254 | | 3775 |
| 2024 | 30 | | | | | | | | | 254 | | 3751 |
| 2025 | 30 | | | | | | | | | 254 | | 2951 |
| 2026 | 30 | | | | | | | | | 254 | | 2640 |
| 2027 | 30 | | | | | | | | | 254 | | 2606 |
| 2028 | 30 | | | | | | | | | 254 | | 2362 |

**Seasonal Participation Purchases - Winter**

| | Barron | Calpine | CMMPA | Coyote | Cyprus | Dynegy | Fibrominn | GenSys | Invenergy | Laurentian | LS Power | Manitoba Hydro | MN Power | Minnkota | Non-Utility Group | St. Paul Co-gen | Wind (Accredited Capacity) | Wisconsin Public Service | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 4 | | 25 | 100 | | 100 | | | | | | 500 | | 20 | 381 | | 46 | | 1176 |
| 2004 | | | 25 | 100 | | | | | | | | 500 | 100 | | 381 | | 65 | | 1171 |
| 2005 | | | 25 | 100 | | | | 50 | | | | 500 | 100 | | 381 | | 71 | | 1227 |
| 2006 | | 375 | 31 | 100 | 40 | | | 50 | | | 275 | 500 | 100 | | 85 | 25 | 92 | 87 | 1760 |
| 2007 | | 375 | | 100 | 40 | 108 | 50 | | | 35 | 275 | 713 | 100 | | 85 | 25 | 122 | | 2028 |
| 2008 | | 375 | | 100 | 40 | | 50 | | 350 | 35 | 275 | 713 | | | 85 | 25 | 168 | | 2216 |
| 2009 | | 375 | | 100 | 40 | | 50 | | 350 | 35 | 275 | 500 | | | 85 | 25 | 178 | | 2013 |
| 2010 | | 375 | | 100 | 40 | | 50 | | 350 | 35 | 275 | 500 | | | 85 | 25 | 207 | | 2042 |
| 2011 | | 375 | | 100 | 40 | | 50 | | 350 | 35 | 275 | 500 | | | 85 | 25 | 224 | | 2059 |
| 2012 | | 375 | | 100 | 40 | | 50 | | 350 | 35 | 275 | 500 | | | 85 | 25 | 254 | | 2089 |
| **2013** | | 375 | | 100 | 40 | | 50 | | 350 | 35 | 275 | 500 | | | 85 | 25 | 254 | | 2089 |
| 2014 | | 375 | | 100 | | | 50 | | 350 | 35 | 275 | 500 | | | 82 | 25 | 254 | | 2046 |
| 2015 | | 375 | | 100 | | | 50 | | 350 | 35 | 275 | 375 | | | 82 | 25 | 254 | | 1921 |
| 2016 | | 375 | | | | | 50 | | 350 | 35 | 275 | 375 | | | 82 | 25 | 254 | | 1821 |
| 2017 | | 375 | | | | | 50 | | 350 | 35 | 275 | 375 | | | 79 | 25 | 254 | | 1818 |
| 2018 | | 375 | | | | | 50 | | 350 | 35 | 275 | 375 | | | 45 | 25 | 254 | | 1784 |
| 2019 | | 375 | | | | | 50 | | 350 | 35 | 275 | 375 | | | 45 | 25 | 254 | | 1784 |
| 2020 | | 375 | | | | | 50 | | 350 | 35 | 275 | 375 | | | 40 | 25 | 254 | | 1779 |
| 2021 | | 375 | | | | | 50 | | 350 | 35 | 275 | 500 | | | 40 | 25 | 254 | | 1904 |
| 2022 | | 375 | | | | | 50 | | 350 | 35 | 275 | 500 | | | 30 | 25 | 254 | | 1894 |
| 2023 | | 375 | | | | | 50 | | 350 | 35 | 275 | 500 | | | 30 | 25 | 254 | | 1894 |
| 2024 | | 375 | | | | | 50 | | 350 | 35 | 275 | 500 | | | 30 | | 254 | | 1869 |
| 2025 | | 375 | | | | | 50 | | | 35 | 275 | | | | 30 | | 254 | | 1019 |
| 2026 | | | | | | | 50 | | | 35 | 275 | | | | 30 | | 254 | | 644 |
| 2027 | | | | | | | 50 | | | | 275 | | | | 30 | | 254 | | 609 |
| 2028 | | | | | | | 50 | | | | | | | | 30 | | 254 | | 334 |

**Seasonal Participation Sales - Summer**

| | Constellation | GenSys | GRE | MDU | Otter Tail | Wisconsin Public Servic | Total |
|---|---|---|---|---|---|---|---|
| 2003 | | | | | | | 0 |
| 2004 | | | | | | | 0 |
| 2005 | | | | | | 200 | 200 |
| 2006 | | | 50 | | 32 | | 82 |
| 2007 | 100 | 50 | 100 | 95 | | | 345 |
| 2008 | | | 150 | 100 | | | 250 |
| 2009 | | | | 105 | | | 105 |
| 2010 | | | | 110 | | | 110 |
| 2011 | | | | | | | 0 |
| 2012 | | | | | | | 0 |
| **2013** | | | | | | | 0 |
| 2014 | | | | | | | 0 |
| 2015 | | | | | | | 0 |
| 2016 | | | | | | | 0 |
| 2017 | | | | | | | 0 |
| 2018 | | | | | | | 0 |
| 2019 | | | | | | | 0 |
| 2020 | | | | | | | 0 |
| 2021 | | | | | | | 0 |
| 2022 | | | | | | | 0 |
| 2023 | | | | | | | 0 |
| 2024 | | | | | | | 0 |
| 2025 | | | | | | | 0 |
| 2026 | | | | | | | 0 |
| 2027 | | | | | | | 0 |
| 2028 | | | | | | | 0 |

**Seasonal Participation Sales - Winter**

| | Melrose | Otter Tail | United Power Assoc. | Total |
|---|---|---|---|---|
| 2003 | | 75 | 50 | 125 |
| 2004 | 3 | 75 | 50 | 128 |
| 2005 | 3 | | 50 | 53 |
| 2006 | | | 50 | 50 |
| 2007 | | | 50 | 50 |
| 2008 | | | 50 | 50 |
| 2009 | | | 50 | 50 |
| 2010 | | | 50 | 50 |
| 2011 | | | | 0 |
| 2012 | | | | 0 |
| **2013** | | | | 0 |
| 2014 | | | | 0 |
| 2015 | | | | 0 |
| 2016 | | | | 0 |
| 2017 | | | | 0 |
| 2018 | | | | 0 |
| 2019 | | | | 0 |
| 2020 | | | | 0 |
| 2021 | | | | 0 |
| 2022 | | | | 0 |
| 2023 | | | | 0 |
| 2024 | | | | 0 |
| 2025 | | | | 0 |
| 2026 | | | | 0 |
| 2027 | | | | 0 |
| 2028 | | | | 0 |

## *D. Loads & Resources – Excluding Resources that Need CON to be Issued*

### Loads and Generation Capacity Data - Summer
### EXCLUDING RESOURCES THAT NEED CON ISSUED

| | Seasonal System Demand | Annual System Demand | Total Seasonal Firm Purchases | Total Seasonal Firm Sales | Seasonal Adjusted Net Demand | Annual Adjusted Net Demand | Net Generating Capacity | Total Participation Purchases | Total Participation Sales | Adjusted Net Capability | Net Reserve Capacity Obligation | Total Firm Capacity Obligation | Surplus or Deficit |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 8281 | 8281 | 512 | 15 | 7784 | 7784 | 7226 | 2087 | 0 | 9313 | 1168 | 8951 | 362 |
| 2004 | 8596 | 8596 | 477 | 16 | 8135 | 8135 | 7229 | 2326 | 0 | 9555 | 1220 | 9355 | 200 |
| 2005 | 8501 | 8501 | 477 | 0 | 8024 | 8024 | 7732 | 2064 | 200 | 9596 | 1204 | 9227 | 369 |
| 2006 | 9034 | 9034 | 487 | 0 | 8547 | 8547 | 7627 | 2773 | 82 | 10318 | 1282 | 9829 | 489 |
| 2007 | 9427 | 9427 | 352 | 0 | 9075 | 9075 | 7577 | 2951 | 345 | 10183 | 1361 | 10436 | -254 |
| 2008 | 10302 | 10302 | 352 | 0 | 9950 | 9950 | 7432 | 3132 | 250 | 10314 | 1493 | 11443 | -1129 |
| 2009 | 8749 | 8749 | 352 | 0 | 8397 | 8397 | 7561 | 2422 | 105 | 9878 | 1260 | 9656 | 222 |
| 2010 | 8826 | 8826 | 352 | 0 | 8474 | 8474 | 7582 | 2320 | 110 | 9791 | 1017 | 9491 | 301 |
| 2011 | 9315 | 9315 | 352 | 0 | 7938 | 7938 | 7497 | 1911 | 0 | 9408 | 953 | 8891 | 517 |
| 2012 | 9483 | 9483 | 352 | 0 | 8090 | 8090 | 7686 | 1880 | 0 | 9566 | 971 | 9060 | 506 |
| **2013** | 9237 | 9237 | 363 | 0 | 8874 | 8874 | 8143 | 1795 | 0 | 9938 | 350 | 9224 | 714 |
| 2014 | 9328 | 9328 | 363 | 0 | 8965 | 8965 | 8154 | 1796 | 0 | 9950 | 354 | 9319 | 632 |
| 2015 | 9428 | 9428 | 342 | 0 | 9087 | 9087 | 7926 | 1675 | 0 | 9601 | 357 | 9444 | 157 |
| 2016 | 9524 | 9524 | 342 | 0 | 9183 | 9183 | 7991 | 1584 | 0 | 9576 | 361 | 9543 | 32 |
| 2017 | 9613 | 9613 | 342 | 0 | 9271 | 9271 | 7899 | 1583 | 0 | 9481 | 364 | 9635 | -154 |
| 2018 | 9708 | 9708 | 342 | 0 | 9367 | 9367 | 7857 | 1558 | 0 | 9415 | 368 | 9735 | -319 |
| 2019 | 9799 | 9799 | 342 | 0 | 9457 | 9457 | 7853 | 1532 | 0 | 9385 | 371 | 9829 | -443 |
| 2020 | 9881 | 9881 | 342 | 0 | 9539 | 9539 | 7849 | 1533 | 0 | 9382 | 374 | 9914 | -532 |
| 2021 | 9963 | 9963 | 342 | 0 | 9622 | 9622 | 7730 | 1656 | 0 | 9387 | 378 | 9999 | -612 |
| 2022 | 10029 | 10029 | 342 | 0 | 9688 | 9688 | 7726 | 1648 | 0 | 9374 | 380 | 10068 | -694 |
| 2023 | 10082 | 10082 | 342 | 0 | 9741 | 9741 | 7722 | 1606 | 0 | 9328 | 382 | 10123 | -795 |
| 2024 | 10123 | 10123 | 342 | 0 | 9781 | 9781 | 7666 | 1596 | 0 | 9261 | 384 | 10165 | -904 |
| 2025 | 10151 | 10151 | 0 | 0 | 10151 | 10151 | 7662 | 797 | 0 | 8458 | 385 | 10535 | -2077 |
| 2026 | 10177 | 10177 | 0 | 0 | 10177 | 10177 | 7657 | 785 | 0 | 8443 | 386 | 10562 | -2120 |
| 2027 | 10233 | 10233 | 0 | 0 | 10233 | 10233 | 7397 | 425 | 0 | 7822 | 388 | 10620 | -2798 |
| 2028 | 10270 | 10270 | 0 | 0 | 10270 | 10270 | 7393 | 192 | 0 | 7584 | 389 | 10660 | -3075 |

## Loads and Generation Capacity Data - Winter
## EXCLUDING RESOURCES THAT NEED CON ISSUED

| | Seasonal System Demand | Annual System Demand | Total Seasonal Firm Purchases | Total Seasonal Firm Sales | Seasonal Adjusted Net Demand | Annual Adjusted Net Demand | Net Generating Capacity | Total Participation Purchases | Total Participation Sales | Adjusted Net Capability | Net Reserve Capacity Obligation | Total Firm Capacity Obligation | Surplus or Deficit |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 6386 | 8281 | 2 | 365 | 6749 | 8644 | 7738 | 1176 | 125 | 8789 | 1297 | 8045 | 743 |
| 2004 | 6653 | 8596 | 127 | 365 | 6891 | 8834 | 7718 | 1123 | 128 | 8713 | 1325 | 8216 | 497 |
| 2005 | 6873 | 8501 | 127 | 366 | 7112 | 8740 | 7718 | 1173 | 53 | 8838 | 1311 | 8423 | 415 |
| 2006 | 6833 | 9034 | 131 | 365 | 7067 | 9268 | 7936 | 1729 | 50 | 9615 | 1390 | 8457 | 1158 |
| 2007 | 7413 | 9427 | 2 | 350 | 7760 | 9775 | 7616 | 1982 | 50 | 9548 | 1466 | 9227 | 321 |
| 2008 | 7509 | 10302 | 2 | 350 | 7856 | 10650 | 7895 | 2124 | 50 | 9969 | 1598 | 9454 | 515 |
| 2009 | 6915 | 8749 | 2 | 350 | 7263 | 9096 | 7773 | 1931 | 50 | 9654 | 1364 | 8627 | 1027 |
| 2010 | 6893 | 8826 | 2 | 350 | 6216 | 9174 | 8368 | 1937 | 50 | 10254 | 1101 | 7317 | 2937 |
| 2011 | 7193 | 9315 | 2 | 350 | 6499 | 8638 | 7120 | 1953 | 0 | 9073 | 1037 | 7535 | 1538 |
| 2012 | 7312 | 9483 | 2 | 350 | 6610 | 8789 | 7211 | 1938 | 0 | 9149 | 1055 | 7665 | 1484 |
| **2013** | 7089 | 7089 | 2 | 350 | 7437 | 7437 | 8062 | 2087 | 0 | 10149 | 269 | 7705 | 2444 |
| 2014 | 7167 | 7167 | 2 | 350 | 7515 | 7515 | 8061 | 2087 | 0 | 10149 | 272 | 7787 | 2362 |
| 2015 | 7246 | 7246 | 2 | 350 | 7594 | 7594 | 7822 | 1917 | 0 | 9739 | 275 | 7869 | 1870 |
| 2016 | 7321 | 7321 | 2 | 350 | 7669 | 7669 | 7898 | 1917 | 0 | 9814 | 277 | 7946 | 1868 |
| 2017 | 7391 | 7391 | 2 | 350 | 7739 | 7739 | 7778 | 1914 | 0 | 9692 | 280 | 8019 | 1673 |
| 2018 | 7464 | 7464 | 2 | 350 | 7812 | 7812 | 7738 | 1883 | 0 | 9621 | 283 | 8095 | 1526 |
| 2019 | 7531 | 7531 | 2 | 350 | 7879 | 7879 | 7738 | 1831 | 0 | 9569 | 285 | 8164 | 1405 |
| 2020 | 7598 | 7598 | 2 | 350 | 7946 | 7946 | 7738 | 1831 | 0 | 9569 | 288 | 8234 | 1335 |
| 2021 | 7666 | 7666 | 0 | 350 | 8016 | 8016 | 7585 | 1945 | 0 | 9530 | 291 | 8306 | 1224 |
| 2022 | 7713 | 7713 | 0 | 350 | 8063 | 8063 | 7586 | 1940 | 0 | 9526 | 292 | 8355 | 1170 |
| 2023 | 7752 | 7752 | 0 | 350 | 8102 | 8102 | 7586 | 1915 | 0 | 9501 | 294 | 8396 | 1105 |
| 2024 | 7782 | 7782 | 0 | 350 | 8132 | 8132 | 7533 | 1915 | 0 | 9448 | 295 | 8427 | 1021 |
| 2025 | 7802 | 7802 | 0 | 0 | 7802 | 7802 | 7533 | 1117 | 0 | 8650 | 296 | 8098 | 552 |
| 2026 | 7828 | 7828 | 0 | 0 | 7828 | 7828 | 7534 | 645 | 0 | 8179 | 297 | 8124 | 54 |
| 2027 | 7833 | 7833 | 0 | 0 | 7833 | 7833 | 7196 | 383 | 0 | 7579 | 297 | 8130 | -551 |
| 2028 | 7862 | 7862 | 0 | 0 | 7862 | 7862 | 7196 | 314 | 0 | 7510 | 298 | 8159 | -650 |

*E. Loads & Resources – Including Proposed Resources*

## Loads and Generation Capacity Data - Summer
## INCLUDING PROPOSED RESOURCES

| | Seasonal System Demand | Annual System Demand | Total Seasonal Firm Purchases | Total Seasonal Firm Sales | Seasonal Adjusted Net Demand | Annual Adjusted Net Demand | Net Generating Capacity | Total Participation Purchases | Total Participation Sales | Adjusted Net Capability | Net Reserve Capacity Obligation | Total Firm Capacity Obligation | Surplus or Deficit |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 8281 | 8281 | 512 | 15 | 7784 | 7784 | 7226 | 2087 | 0 | 9313 | 1168 | 8951 | 362 |
| 2004 | 8596 | 8596 | 477 | 16 | 8135 | 8135 | 7229 | 2326 | 0 | 9555 | 1220 | 9355 | 200 |
| 2005 | 8501 | 8501 | 477 | 0 | 8024 | 8024 | 7732 | 2064 | 200 | 9596 | 1204 | 9227 | 369 |
| 2006 | 9034 | 9034 | 487 | 0 | 8547 | 8547 | 7627 | 2773 | 82 | 10318 | 1282 | 9829 | 489 |
| 2007 | 9427 | 9427 | 352 | 0 | 9075 | 9075 | 7577 | 2951 | 345 | 10183 | 1361 | 10436 | -254 |
| 2008 | 10302 | 10302 | 352 | 0 | 9950 | 9950 | 7432 | 3132 | 250 | 10314 | 1493 | 11443 | -1129 |
| 2009 | 8749 | 8749 | 352 | 0 | 8397 | 8397 | 7561 | 2422 | 105 | 9878 | 1260 | 9656 | 222 |
| 2010 | 8826 | 8826 | 352 | 0 | 8474 | 8474 | 7582 | 2320 | 110 | 9791 | 1017 | 9491 | 301 |
| 2011 | 9315 | 9315 | 352 | 0 | 7938 | 7938 | 7497 | 1911 | 0 | 9408 | 953 | 8891 | 517 |
| 2012 | 9483 | 9483 | 352 | 0 | 8090 | 8090 | 7686 | 1880 | 0 | 9566 | 971 | 9060 | 506 |
| **2013** | 9237 | 9237 | 363 | 0 | 8874 | 8874 | 8143 | 1795 | 0 | 9938 | 350 | 9224 | 714 |
| 2014 | 9328 | 9328 | 363 | 0 | 8965 | 8965 | 8154 | 1796 | 0 | 9950 | 354 | 9319 | 632 |
| 2015 | 9428 | 9428 | 342 | 0 | 9087 | 9087 | 7926 | 1675 | 0 | 9601 | 357 | 9444 | 157 |
| 2016 | 9524 | 9524 | 342 | 0 | 9183 | 9183 | 7991 | 1584 | 0 | 9576 | 361 | 9543 | 32 |
| 2017 | 9613 | 9613 | 342 | 0 | 9271 | 9271 | 8107 | 1583 | 0 | 9690 | 364 | 9635 | 54 |
| 2018 | 9708 | 9708 | 342 | 0 | 9367 | 9367 | 8482 | 1558 | 0 | 10040 | 368 | 9735 | 306 |
| 2019 | 9799 | 9799 | 342 | 0 | 9457 | 9457 | 8478 | 1532 | 0 | 10010 | 371 | 9829 | 182 |
| 2020 | 9881 | 9881 | 342 | 0 | 9539 | 9539 | 8474 | 1533 | 0 | 10007 | 374 | 9914 | 94 |
| 2021 | 9963 | 9963 | 342 | 0 | 9622 | 9622 | 8355 | 1656 | 0 | 10012 | 378 | 9999 | 13 |
| 2022 | 10029 | 10029 | 342 | 0 | 9688 | 9688 | 8351 | 1648 | 0 | 9999 | 380 | 10068 | -69 |
| 2023 | 10082 | 10082 | 342 | 0 | 9741 | 9741 | 8347 | 1606 | 0 | 9953 | 382 | 10123 | -170 |
| 2024 | 10123 | 10123 | 342 | 0 | 9781 | 9781 | 8291 | 1596 | 0 | 9886 | 384 | 10165 | -279 |
| 2025 | 10151 | 10151 | 0 | 0 | 10151 | 10151 | 8287 | 797 | 0 | 9083 | 385 | 10535 | -1452 |
| 2026 | 10177 | 10177 | 0 | 0 | 10177 | 10177 | 8283 | 785 | 0 | 9068 | 386 | 10562 | -1494 |
| 2027 | 10233 | 10233 | 0 | 0 | 10233 | 10233 | 8022 | 425 | 0 | 8447 | 388 | 10620 | -2173 |
| 2028 | 10270 | 10270 | 0 | 0 | 10270 | 10270 | 8018 | 192 | 0 | 8210 | 389 | 10660 | -2450 |

# Loads and Generation Capacity Data - Winter
# INCLUDING PROPOSED RESOURCES

| | Seasonal System Demand | Annual System Demand | Total Seasonal Firm Purchases | Total Seasonal Firm Sales | Seasonal Adjusted Net Demand | Annual Adjusted Net Demand | Net Generating Capacity | Total Participation Purchases | Total Participation Sales | Adjusted Net Capability | Net Reserve Capacity Obligation | Total Firm Capacity Obligation | Surplus or Deficit |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 6386 | 8281 | 2 | 365 | 6749 | 8644 | 7738 | 1176 | 125 | 8789 | 1297 | 8045 | 743 |
| 2004 | 6653 | 8596 | 127 | 365 | 6891 | 8834 | 7718 | 1123 | 128 | 8713 | 1325 | 8216 | 497 |
| 2005 | 6873 | 8501 | 127 | 366 | 7112 | 8740 | 7718 | 1173 | 53 | 8838 | 1311 | 8423 | 415 |
| 2006 | 6833 | 9034 | 131 | 365 | 7067 | 9268 | 7936 | 1729 | 50 | 9615 | 1390 | 8457 | 1158 |
| 2007 | 7413 | 9427 | 2 | 350 | 7760 | 9775 | 7616 | 1982 | 50 | 9548 | 1466 | 9227 | 321 |
| 2008 | 7509 | 10302 | 2 | 350 | 7856 | ### | 7895 | 2124 | 50 | 9969 | 1598 | 9454 | 515 |
| 2009 | 6915 | 8749 | 2 | 350 | 7263 | 9096 | 7773 | 1931 | 50 | 9654 | 1364 | 8627 | 1027 |
| 2010 | 6893 | 8826 | 2 | 350 | 6216 | 9174 | 8368 | 1937 | 50 | 10254 | 1101 | 7317 | 2937 |
| 2011 | 7193 | 9315 | 2 | 350 | 6499 | 8638 | 7120 | 1953 | 0 | 9073 | 1037 | 7535 | 1538 |
| 2012 | 7312 | 9483 | 2 | 350 | 6610 | 8789 | 7211 | 1938 | 0 | 9149 | 1055 | 7665 | 1484 |
| **2013** | 7089 | 7089 | 2 | 350 | 7437 | 7437 | 8062 | 2087 | 0 | 10149 | 269 | 7705 | 2444 |
| 2014 | 7167 | 7167 | 2 | 350 | 7515 | 7515 | 8061 | 2087 | 0 | 10149 | 272 | 7787 | 2362 |
| 2015 | 7246 | 7246 | 2 | 350 | 7594 | 7594 | 7822 | 1917 | 0 | 9739 | 275 | 7869 | 1870 |
| 2016 | 7321 | 7321 | 2 | 350 | 7669 | 7669 | 7898 | 1917 | 0 | 9814 | 277 | 7946 | 1868 |
| 2017 | 7391 | 7391 | 2 | 350 | 7739 | 7739 | 8003 | 1914 | 0 | 9917 | 280 | 8019 | 1898 |
| 2018 | 7464 | 7464 | 2 | 350 | 7812 | 7812 | 8413 | 1883 | 0 | 10296 | 283 | 8095 | 2201 |
| 2019 | 7531 | 7531 | 2 | 350 | 7879 | 7879 | 8413 | 1831 | 0 | 10244 | 285 | 8164 | 2080 |
| 2020 | 7598 | 7598 | 2 | 350 | 7946 | 7946 | 8412 | 1831 | 0 | 10244 | 288 | 8234 | 2010 |
| 2021 | 7666 | 7666 | 0 | 350 | 8016 | 8016 | 8260 | 1945 | 0 | 10204 | 291 | 8306 | 1898 |
| 2022 | 7713 | 7713 | 0 | 350 | 8063 | 8063 | 8260 | 1940 | 0 | 10200 | 292 | 8355 | 1845 |
| 2023 | 7752 | 7752 | 0 | 350 | 8102 | 8102 | 8260 | 1915 | 0 | 10175 | 294 | 8396 | 1779 |
| 2024 | 7782 | 7782 | 0 | 350 | 8132 | 8132 | 8208 | 1915 | 0 | 10123 | 295 | 8427 | 1696 |
| 2025 | 7802 | 7802 | 0 | 0 | 7802 | 7802 | 8207 | 1117 | 0 | 9325 | 296 | 8098 | 1227 |
| 2026 | 7828 | 7828 | 0 | 0 | 7828 | 7828 | 8208 | 645 | 0 | 8853 | 297 | 8124 | 729 |
| 2027 | 7833 | 7833 | 0 | 0 | 7833 | 7833 | 7871 | 383 | 0 | 8254 | 297 | 8130 | 124 |
| 2028 | 7862 | 7862 | 0 | 0 | 7862 | 7862 | 7870 | 314 | 0 | 8184 | 298 | 8159 | 25 |

*F. Loads & Resources – Including All Planned Resources*

## Loads and Generation Capacity Data - Summer
## INCLUDING ALL PLANNED RESOURCES

| | Seasonal System Demand | Annual System Demand | Total Seasonal Firm Purchases | Total Seasonal Firm Sales | Seasonal Adjusted Net Demand | Annual Adjusted Net Demand | Net Generating Capacity | Total Participation Purchases | Total Participation Sales | Adjusted Net Capability | Net Reserve Capacity Obligation | Total Firm Capacity Obligation | Surplus or Deficit |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 8281 | 8281 | 512 | 15 | 7784 | 7784 | 7226 | 2087 | 0 | 9313 | 1168 | 8951 | 362 |
| 2004 | 8596 | 8596 | 477 | 16 | 8135 | 8135 | 7229 | 2326 | 0 | 9555 | 1220 | 9355 | 200 |
| 2005 | 8501 | 8501 | 477 | 0 | 8024 | 8024 | 7732 | 2064 | 200 | 9596 | 1204 | 9227 | 369 |
| 2006 | 9034 | 9034 | 487 | 0 | 8547 | 8547 | 7627 | 2773 | 82 | 10318 | 1282 | 9829 | 489 |
| 2007 | 9427 | 9427 | 352 | 0 | 9075 | 9075 | 7577 | 2951 | 345 | 10183 | 1361 | 10436 | -254 |
| 2008 | 10302 | 10302 | 352 | 0 | 9950 | 9950 | 7432 | 3132 | 250 | 10314 | 1493 | 11443 | -1129 |
| 2009 | 8749 | 8749 | 352 | 0 | 8397 | 8397 | 7561 | 2422 | 105 | 9878 | 1260 | 9656 | 222 |
| 2010 | 8826 | 8826 | 352 | 0 | 8474 | 8474 | 7582 | 2320 | 110 | 9791 | 1017 | 9491 | 301 |
| 2011 | 9315 | 9315 | 352 | 0 | 7938 | 7938 | 7497 | 1911 | 0 | 9408 | 953 | 8891 | 517 |
| 2012 | 9483 | 9483 | 352 | 0 | 8090 | 8090 | 7686 | 1880 | 0 | 9566 | 971 | 9060 | 506 |
| **2013** | 9237 | 9237 | 363 | 0 | 8874 | 8874 | 8143 | 1795 | 0 | 9938 | 350 | 9224 | 714 |
| 2014 | 9328 | 9328 | 363 | 0 | 8965 | 8965 | 8154 | 1796 | 0 | 9950 | 354 | 9319 | 632 |
| 2015 | 9428 | 9428 | 342 | 0 | 9087 | 9087 | 7952 | 1675 | 0 | 9627 | 357 | 9444 | 183 |
| 2016 | 9524 | 9524 | 342 | 0 | 9183 | 9183 | 8017 | 1584 | 0 | 9602 | 361 | 9543 | 58 |
| 2017 | 9613 | 9613 | 342 | 0 | 9271 | 9271 | 8133 | 1583 | 0 | 9716 | 364 | 9635 | 80 |
| 2018 | 9708 | 9708 | 342 | 0 | 9367 | 9367 | 8508 | 1558 | 0 | 10066 | 368 | 9735 | 332 |
| 2019 | 9799 | 9799 | 342 | 0 | 9457 | 9457 | 8504 | 1532 | 0 | 10036 | 371 | 9829 | 208 |
| 2020 | 9881 | 9881 | 342 | 0 | 9539 | 9539 | 8526 | 1533 | 0 | 10059 | 374 | 9914 | 145 |
| 2021 | 9963 | 9963 | 342 | 0 | 9622 | 9622 | 8597 | 1656 | 0 | 10253 | 378 | 9999 | 254 |
| 2022 | 10029 | 10029 | 342 | 0 | 9688 | 9688 | 8618 | 1648 | 0 | 10266 | 380 | 10068 | 198 |
| 2023 | 10082 | 10082 | 342 | 0 | 9741 | 9741 | 8614 | 1606 | 0 | 10220 | 382 | 10123 | 97 |
| 2024 | 10123 | 10123 | 342 | 0 | 9781 | 9781 | 8760 | 1596 | 0 | 10356 | 384 | 10165 | 191 |
| 2025 | 10151 | 10151 | 0 | 0 | 10151 | 10151 | 9855 | 797 | 0 | 10652 | 385 | 10535 | 116 |
| 2026 | 10177 | 10177 | 0 | 0 | 10177 | 10177 | 9864 | 785 | 0 | 10649 | 386 | 10562 | 87 |
| 2027 | 10233 | 10233 | 0 | 0 | 10233 | 10233 | 10323 | 425 | 0 | 10749 | 388 | 10620 | 128 |
| 2028 | 10270 | 10270 | 0 | 0 | 10270 | 10270 | 10698 | 192 | 0 | 10890 | 389 | 10660 | 230 |

# Loads and Generation Capacity Data - Winter
# INCLUDING ALL PLANNED RESOURCES

| | Seasonal System Demand | Annual System Demand | Total Seasonal Firm Purchases | Total Seasonal Firm Sales | Seasonal Adjusted Net Demand | Annual Adjusted Net Demand | Net Generating Capacity | Total Participation Purchases | Total Participation Sales | Adjusted Net Capability | Net Reserve Capacity Obligation | Total Firm Capacity Obligation | Surplus or Deficit |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 6386 | 8281 | 2 | 365 | 6749 | 8644 | 7738 | 1176 | 125 | 8789 | 1297 | 8045 | 743 |
| 2004 | 6653 | 8596 | 127 | 365 | 6891 | 8834 | 7718 | 1123 | 128 | 8713 | 1325 | 8216 | 497 |
| 2005 | 6873 | 8501 | 127 | 366 | 7112 | 8740 | 7718 | 1173 | 53 | 8838 | 1311 | 8423 | 415 |
| 2006 | 6833 | 9034 | 131 | 365 | 7067 | 9268 | 7936 | 1729 | 50 | 9615 | 1390 | 8457 | 1158 |
| 2007 | 7413 | 9427 | 2 | 350 | 7760 | 9775 | 7616 | 1982 | 50 | 9548 | 1466 | 9227 | 321 |
| 2008 | 7509 | 10302 | 2 | 350 | 7856 | ### | 7895 | 2124 | 50 | 9969 | 1598 | 9454 | 515 |
| 2009 | 6915 | 8749 | 2 | 350 | 7263 | 9096 | 7773 | 1931 | 50 | 9654 | 1364 | 8627 | 1027 |
| 2010 | 6893 | 8826 | 2 | 350 | 6216 | 9174 | 8368 | 1937 | 50 | 10254 | 1101 | 7317 | 2937 |
| 2011 | 7193 | 9315 | 2 | 350 | 6499 | 8638 | 7120 | 1953 | 0 | 9073 | 1037 | 7535 | 1538 |
| 2012 | 7312 | 9483 | 2 | 350 | 6610 | 8789 | 7211 | 1938 | 0 | 9149 | 1055 | 7665 | 1484 |
| **2013** | 7089 | 7089 | 2 | 350 | 7437 | 7437 | 8062 | 2087 | 0 | 10149 | 269 | 7705 | 2444 |
| 2014 | 7167 | 7167 | 2 | 350 | 7515 | 7515 | 8061 | 2087 | 0 | 10149 | 272 | 7787 | 2362 |
| 2015 | 7246 | 7246 | 2 | 350 | 7594 | 7594 | 7872 | 1917 | 0 | 9789 | 275 | 7869 | 1920 |
| 2016 | 7321 | 7321 | 2 | 350 | 7669 | 7669 | 7948 | 1917 | 0 | 9864 | 277 | 7946 | 1918 |
| 2017 | 7391 | 7391 | 2 | 350 | 7739 | 7739 | 8053 | 1914 | 0 | 9967 | 280 | 8019 | 1948 |
| 2018 | 7464 | 7464 | 2 | 350 | 7812 | 7812 | 8463 | 1883 | 0 | 10346 | 283 | 8095 | 2251 |
| 2019 | 7531 | 7531 | 2 | 350 | 7879 | 7879 | 8463 | 1831 | 0 | 10294 | 285 | 8164 | 2130 |
| 2020 | 7598 | 7598 | 2 | 350 | 7946 | 7946 | 8590 | 1831 | 0 | 10421 | 288 | 8234 | 2187 |
| 2021 | 7666 | 7666 | 0 | 350 | 8016 | 8016 | 8654 | 1945 | 0 | 10598 | 291 | 8306 | 2292 |
| 2022 | 7713 | 7713 | 0 | 350 | 8063 | 8063 | 8782 | 1940 | 0 | 10722 | 292 | 8355 | 2366 |
| 2023 | 7752 | 7752 | 0 | 350 | 8102 | 8102 | 8782 | 1915 | 0 | 10697 | 294 | 8396 | 2301 |
| 2024 | 7782 | 7782 | 0 | 350 | 8132 | 8132 | 9009 | 1915 | 0 | 10924 | 295 | 8427 | 2498 |
| 2025 | 7802 | 7802 | 0 | 0 | 7802 | 7802 | 10299 | 1117 | 0 | 11416 | 296 | 8098 | 3318 |
| 2026 | 7828 | 7828 | 0 | 0 | 7828 | 7828 | 10363 | 645 | 0 | 11008 | 297 | 8124 | 2884 |
| 2027 | 7833 | 7833 | 0 | 0 | 7833 | 7833 | 10882 | 383 | 0 | 11265 | 297 | 8130 | 3135 |
| 2028 | 7862 | 7862 | 0 | 0 | 7862 | 7862 | 11315 | 314 | 0 | 11629 | 298 | 8159 | 3469 |

## *G. Resource Additions & Retirements*

### Additions

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| SolrRwds 1 MW | SolrRwds 1 MW | SolrRwds 1 MW | SolrRwds 1 MW | SolrRwds 1 MW | SolrRwds 1 MW |
| Monti EPU 65 MW | | MH 5x16 366 MW | Fch Isld 3 57 MW | BD CT 6 215 MW | RRV 1CT 215MW |
| CrownHyd 1 MW | | MH Diveristy 342 MW | | | |
| | | WIND 200MW | | | |

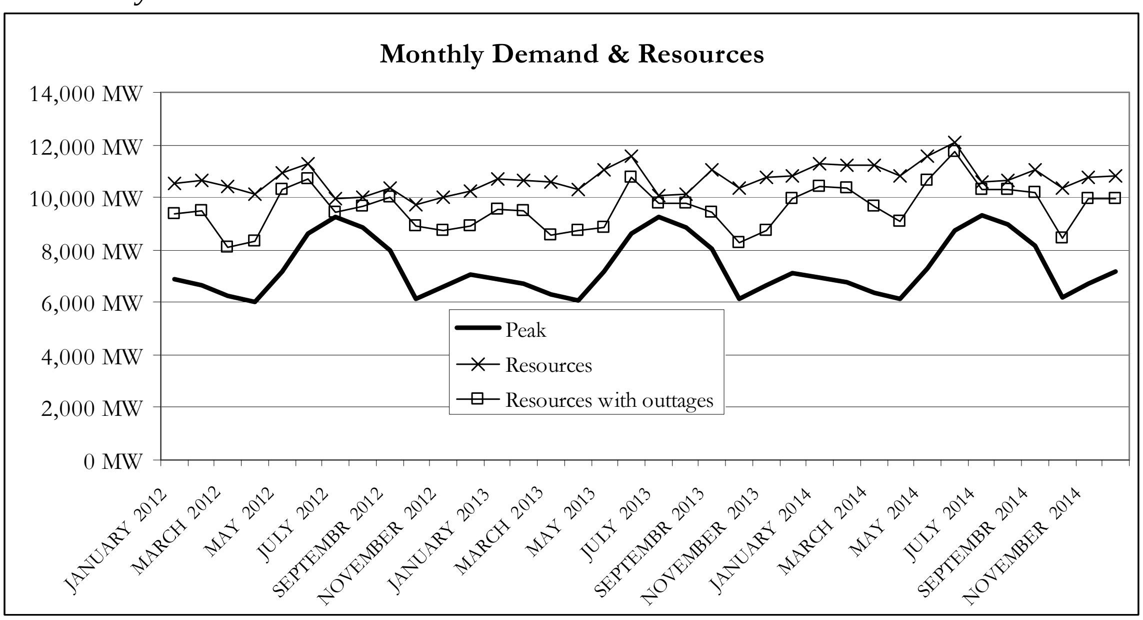
| 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|
| SolrRwds 1 MW | WIND 200MW | SolrRwds 1 MW | WIND 100MW | WIND 100MW | WIND 100MW |
| MH 5X16 122 MW | SolrRwds 1 MW | | SolrRwds 1 MW | SolrRwds 1 MW | SolrRwds 1 MW |
| Generic CT 189 MW | | | Generic CT 189 MW | Generic CC 707 MW | |
| | | | | Generic CT 189 MW | |
| | | | | Generic CT 189 MW | |

### Retirements

| 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| | MH 5x16 -488 MW | Coyote 1 -92 MW | Rapidan -3 MW | Wilmarth 1 -12 MW | WindPowr -19 MW |
| | MH Diversity -208 MW | | Key City 4 -15 MW | Viking -2 MW | Moraine -106 MW |
| | MH Diversity -156 MW | | Key City 3 -14 MW | Red Wing 1 -12 MW | Rahr Malting -11 MW |
| | BlackDog 4 -156 MW | | Key City 2 -14 MW | HERC -24 MW | |
| | BlackDog 3 -84 MW | | Granite 4 -13 MW | Flambeau 1 -12 MW | |
| | | | Granite 3 -14 MW | | |
| | | | Granite 2 -14 MW | | |
| | | | Granite 1 -13 MW | | |

| 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|
| St.Cloud -8 MW | St Paul -23 MW | Fch Isld 1 -9 MW | Stahl -9 MW | Velva -8 MW | Laurentn 1 -35 MW |
| | MNDakota -150MW | Chanaram -96 MW | MNWind -11 MW | Tholen -13 MW | Inverhil 6 -45 MW |
| | | Bayfront 6 -12 MW | MH 5x16 -488 MW | PineBend -5 MW | Inverhil 5 -42 MW |
| | | Bayfront 5 -20 MW | LkBnton2 -97 MW | Norgaard -8 MW | Inverhil 4 -40 MW |
| | | Bayfront 4 -11 MW | Invenerg 2 -144 MW | Garmcn -7 MW | Inverhil 3 -41 MW |
| | | | Invenerg 1 -151 MW | Eastridg -8 MW | Inverhil 2 -44 MW |
| | | | MH Diveristy -342 MW | | Inverhil 1 -42 MW |
| | | | | | InverDsl 7 -4 MW |
| | | | | | FPL Mowr -99 MW |
| | | | | | CalpMnkt 1 -313 MW |

## *H. Monthly Demand & Resources*



### *I. Appropriateness of System Reserve Margins*

Please see chapter 3 for a full discussion of reserve margin calculations used by the Company.

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

| | |
|---|---|
| Beverly Jones Heydinger | Chair |
| David C. Boyd | Commissioner |
| Nancy Lange | Commissioner |
| J. Dennis O'Brien | Commissioner |
| Betsy Wergin | Commissioner |

In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan

ISSUE DATE: March 5, 2013

DOCKET NO. E-002/RP-10-825

ORDER APPROVING PLAN, FINDING NEED, ESTABLISHING FILING REQUIREMENTS, AND CLOSING DOCKET

## PROCEDURAL HISTORY

On August 2, 2010, Northern States Power Company d/b/a Xcel Energy (Xcel) filed a resource plan under Minn. Stat. § 216B.2422 and Minn. R. 7843.0400, covering the period 2011-2025. Since that time Xcel has occasionally revised the data upon which its plan was based, and also revised its plans.

On November 30, 2012, the Commission issued its Order Establishing Procedural Schedules and Filing Requirements which, among other things, did the following:

- Established a schedule for filing forecasts of the amount of additional resources Xcel would need to meet customer demand, and for filing comments on the forecasts.

- Directed Xcel to file a notice plan for soliciting bids in Docket No. E-002/CN-12-1240, *In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy to Initiate a Competitive Resource Acquisition Process.*

- Directed Xcel to develop a plan to either update or replace the Sherburne County (Sherco) Generating Station Units 1 and 2, the two oldest coal-powered generators at Xcel's largest plant.

- Identified topics for Xcel to address in its next resource plan.

Since November 30, 2012, the Commission has received comments from the following:

- Minnesota Department of Commerce (the Department)
- Calpine Corporation, a developer of electric generators

- Flint Hills Resources, LP, Gerdau Ameristeel Corporation, and USG Corporation, filing jointly (the Xcel Large Industrials)
- Izaak Walton League of America – Midwest Office, Fresh Energy, Sierra Club, and the Minnesota Center for Environmental Advocacy, filing jointly (the Environmental Intervenors)
- Xcel

On February 20, 2013, the Commission met to consider the matter.

## FINDINGS AND CONCLUSIONS

### I. Summary

In the order the Commission does the following:

- Approves Xcel's resource plan for planning purposes and closes the current docket.

- Finds that the record demonstrates a need for an additional 150 MW by 2017, increasing up to 500 MW by 2019.

- Authorizes entities to propose to provide the resources for meeting some or all of Xcel's needs.

- Provides direction for Xcel's next resource plan.

### II. Legal Background

#### A. Resource Planning

To reliably provide the electricity demanded by its customers, an electric utility considers both supply and demand. The utility can supply electricity through a combination of generation and power purchases, and by reducing the amount of electricity lost through transmission and distribution. The utility can manage its customers' demand by encouraging customers to conserve electricity or to shift activities requiring electricity to periods when there is less demand on the electric system. A resource plan contains a set of demand- and supply-side resource options that the utility could use to meet the forecasted needs of retail customers.[1]

A public utility providing electricity to at least 10,000 customers and capable of generating 100 megawatts (MW) of electricity must file a resource plan or report for the Commission's approval, rejection, or modification.[2] Generally, the resource planning statute and rules direct a utility to file biennial reports on the projected need for electricity in its service territory, and the utility's plans for meeting projected need, including the actions it will take in the next five years.[3] By integrating the evaluation of supply- and demand-side resource options – treating

[1] Minn. Stat. § 216B.2422, subd. 1(d).

[2] Minn. Stat. § 216B.2422, subds. 1 and 4. The statute exempts federal power agencies, and the Commission's findings regarding service providers that are not statutory "public utilities" are merely advisory.

[3] Minn. Stat. § 216B.2422; Minn. R. Chap. 7843.

each resource as a potential substitute for the others – a utility can find the least-cost plan that is consistent with the other legal requirements and policies.

### B. Xcel's Competitive Bidding Process

The Commission authorizes Xcel to secure new resources through a competitive bidding process, as permitted under Minn. Stat. § 216B.2422. subd. 5.[4] Xcel has initiated the process for soliciting proposals for meeting the needs to be identified in this docket.[5]

## III. Positions of the Parties

### A. Xcel

Based on its analysis, Xcel's revised five-year action plan includes the following elements:

- Retiring Black Dog Units 1 and 2, but canceling plans to acquire replacement power.
- Canceling the further expansion of the generating capacity of the Prairie Island Nuclear Power Plant.
- Continuing the operation of the Key City generator in Mankato (43 MW) and Granite City generator near St. Cloud (54 MW) until 2016, and bringing the French Island Unit 3 generator (57 MW) back into service.
- Continuing to analyze whether to update or replace Sherco Units 1 and 2.
- Soliciting proposals for an additional 200 MW of wind-powered electricity.
- Continuing to use demand-side management programs such as offering discounts to customers that permit Xcel to interrupt electric service during time of peak demand, estimated to reduce the demand on Xcel's system during periods of peak demand by approximately 1000 MW.
- Continuing to use demand-side management to reduce energy sales by 1.3 percent, and working with stakeholders to achieve even greater savings.
- Continuing programs involving solar energy, including Solar*Rewards – a program subsidizing customer purchases and installation of photovoltaic solar cells[6] -- albeit with lower subsidies for enrollees.

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[4] See *In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2005 - 2019 Resource Plan*, Docket No. E-002/RP-04-1752, Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, and Requiring Compliance Filing (May 31, 2006).

[5] See *In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy to Initiate a Competitive Resource Acquisition Process*, Docket No. E-002/CN-12-1240, Order Closing Docket, Establishing New Docket, and Schedule for Competitive Resource Acquisition Process (November 21, 2012).

[6] See Docket No. E,G-002/CIP-12-447, *In the Matter of the Implementation of Northern States Power Company, a Minnesota Corporation's 2013/2014/2015 Triennial Natural Gas and Electric Conservation Improvement Program*.

Based on its forecasts, Xcel argues that it will need an additional 154 MW by 2017, 319 MW by 2018, and 443 MW by 2019 to meet anticipated customer demand. Xcel asks the Commission to affirm this level of need, and this degree of specificity, arguing that the information would be useful to entities that might provide resources as part of Xcel's competitive bidding process.

To attract the broadest range of projects for its consideration, Xcel asks the Commission to grant a wide degree of latitude to potential bidders in Xcel's competitive resource acquisition process. In particular, Xcel proposes soliciting bids that 1) meet all or any portion of the need, 2) rely on any fuel type, 3) rely on new or existing generators, and 4) rely on intermediate or peaking generators, or both – that is, any generators other than base-load generators designed to run on a continuous basis.

However, Xcel opposes proposals to reduce the amount of Xcel's forecasted need based on the assumption that Xcel can increase the amount of savings it can achieve through demand-side management. While Xcel's own study concluded that Xcel could save 300 MW through the use of demand-side management, Xcel argues that the study was insufficiently rigorous to provide a basis for altering its demand forecasts.

### B. Environmental Intervenors

The Environmental Intervenors argue that it is premature to close the current docket or initiate a competitive resource acquisition proceeding. Instead, the Environmental Intervenors recommend that the Commission do the following:

- Direct Xcel and the Department to re-analyze Xcel's resource plan based on the latest forecast data.

- Direct Xcel to evaluate the potential savings Xcel could achieve through implementing demand-side management programs, and to quantify these savings with sufficient rigor to enable Xcel to rely on the estimate when forecasting future resource needs.

- Direct Xcel to look for opportunities to integrate solar power into its resource mix.

If and when the Commission initiates the competitive resource acquisition process, the Environmental Intervenors support Xcel's proposal to solicit the broadest range of resources for consideration.

Finally, before the Commission approves any new supply-side resource, the Environmental Intervenors argue that the Commission should require Xcel to demonstrate in a contested case proceeding that Xcel has sufficient need to justifying the new resource, and that the need could not be met more cost-effectively through demand-side management or renewably sources of energy.

### C. Large Power Intervenors

Echoing some of the Environmental Intervenors' concerns, the Large Power Intervenors caution the Commission against overestimating Xcel's needs. They argue that Xcel developed its forecast of customer demand based on data that is now out of date. Moreover, the Large Power Intervenors note that Xcel recently solicited bids for 200 MW of wind power; these new generators may offset Xcel's alleged resource deficits, they argue.

### D. The Department

Using assumptions and analysis that differed somewhat from Xcel's assumptions and analysis, the Department reaches recommendations that are generally similar to Xcel's. In particular, whereas Xcel argues that it will need an addition 443 MW by 2019, the Department predicts that Xcel will need 500 MW within the 2017-2019 timeframe.

The Department also supports Xcel's proposal to grant broad discretion to bidders in Xcel's competitive bidding process. The Department shares Xcel's view that computer models indicate that a variety of alternatives might prove to be the least-cost alternative, and the final choice should be referred to Xcel's resource acquisition docket.

Unlike Xcel, however, the Department asks the Commission to specify that Xcel must pursue new sources of electricity generated from natural gas. According to the Department's analysis, each of ten least-cost scenarios for meeting Xcel's needs involves relying on one or more new gas-fueled generators.

Finally, the Department argues that Xcel should, in its next resource plan, report on the expected amount of solar energy on Xcel's system, barriers Xcel sees to further deployment of solar cells, and new programs for promoting solar power that might replace the Solar*Rewards program.

### E. Calpine

Calpine supports both Xcel's and the Department's proposals to solicit resource proposals broadly, without restricting the type of generators to be considered.

Calpine favors the Department's recommendation to find that Xcel needs 500 MW within the 2017-2019 timeframe. Calpine argues that Xcel's proposal -- identifying a precise level of need for each year – could discourage rather than encourage potential bidders because it may hint that Xcel may have already identified the projects that it will meet those specific targets.

## IV. Commission Analysis and Action

### A. Xcel's Resource Plan

Parties from varying perspectives have now had sufficient opportunity to scrutinize and challenge the data and analysis underlying Xcel's resource plan, and have had the opportunity to share their comments with this Commission. Having reviewed these comments along with the rest of the record, the Commission concludes that Xcel's plan is reliable for planning purposes. Consequently, the Commission will approve it, and will close this docket.

The Environmental Intervenors ask the Commission to refrain from approving the plan until Xcel has further refined it by, for example, considering more recent forecast data. And they argue that approval of Xcel's overall resource plan should not relieve Xcel of the duty to justify the acquisition of any specific resource.

The Commission finds that Xcel has fulfilled the requirements of Minn. Stat. § 216B.2422 and Minn. R. Chap. 7843 governing resource planning. Moreover, Xcel filed revised forecasting data less than three months ago. Rather that attempting to address the Environmental Intervenors' concerns by ordering a further revision of forecasting data, the Commission will refer these concerns to Xcel's next resource plan that Xcel is due to file in the next 11 months.

Finally, the Commission notes that it is approving Xcel's plan for planning purposes only. This approval does not relieve Xcel from the need to comply with any regulatory review required for any specific resource it might pursue in implementing this plan.

### B. Competitive Resource Acquisition Process

The current resource planning docket will have a direct bearing on Xcel's competitive bidding process. In particular, the current docket supports the finding that Xcel will need an additional 150 MW in 2017, increasing up to 500 MW by 2019. Moreover, a broad range of resources could contribute to meeting this need, justifying solicitation of a broad range of proposals. In particular, Xcel should invite proposals for meeting all of the forecasted need, or any part of it. Xcel should invite proposals for adding peaking resource, intermediate resources, or a combination of the two. Xcel should invite proposals that rely on building new generators, as well as proposals that rely on existing generators.

Commentors largely agree about the advantages of considering a broad range of potential resources. While the Department recommends that the Commission direct Xcel to seek gas-fueled sources of generation in particular, the Commission is not persuaded of the need to prohibit consideration of other alternatives. Rather, the Commission is willing to rely on the bid evaluation process to identify the best alternatives, regardless of type.

In contrast, parties disagree about the magnitude of Xcel's needs. For example, the Environmental Intervenors and the Large Power Intervenors argue that the 500 MW figure may exceed customer demand. In contrast, Calpine and the Department argue that the 500 MW figure is justified, and may even be too low.

The idea that Xcel will need an additional 500 MW by 2019 is well-supported in the record. Indeed, Xcel had previously argued that it would need up to 600 MW of additional capacity – and Xcel generated this estimate before it cancelled plans to add 118 MW of new capacity to its Prairie Island plant.

For purposes of Xcel's competitive bidding docket, the Commission finds it appropriate to solicit proposals for *an additional* 150 MW in 2017, increasing *up to* 500 MW by 2019. This statement does not preclude Xcel from acquiring more than 150 MW of new resources by 2017. Those choices will be made in the context of the resource acquisition docket, based on the proposals and the evidence adduced in that docket.

Finally, Xcel asks the Commission to identify the magnitude of Xcel's forecasted need in each of the years 2017, 2018, and 2019, on the theory that this information would be useful to potential bidders. In contrast, Calpine and the Department argue that Xcel's figures suggest an unwarranted degree of precision in the forecasting process. Calpine even suggests that the figures could discourage potential bidders by signaling that Xcel has selected need specifications to justify a pre-determined conclusion.

The Commission concludes that the degree of specificity in Xcel's statement of resource need is unnecessary. A statement that Xcel anticipates needing an additional 150 MW by 2017, increasing up to 500 MW in 2019, will suffice to inform potential bidders of the scope of projects that the Commission will be considering.

### C. Xcel's Next Resource Plan

The Environmental Intervenors, among others, ask the Commission to direct Xcel to further address issues of demand response and solar energy as part of Xcel's resource plan. Rather than prolong the consideration of Xcel's current resource plan, the Commission will adopt the Department's recommendation to have Xcel address these issues in its next plan.

Xcel commissioned a study that suggests that Xcel could avoid the need for an additional 300 MW if Xcel could harness the full potential for demand response in its service area. Xcel argues, however, that the study is too general to be relied upon. For its next resource plan, therefore, the Commission will direct Xcel to analyze the capacity for demand response in its service area – and to conduct the study with sufficient rigor that the Commission may rely on the results for evaluating how demand response will influence Xcel's forecasted need for additional resources.

Similarly, the Commission will direct Xcel to include a report on solar power as part of its next resource plan. This report should note the expected amount of solar energy on Xcel's system, barriers it sees to further solar deployment, and how solar development could contribute to peak demand management, economic development in Minnesota, and meeting Minnesota's renewable energy and environmental mandates and goals.[7]

These filing requirements supplement the other requirements set forth in the Commission's November 30, 2012 order.

## <u>ORDER</u>

1. The Commission approves for planning purposes the 2011-2025 Resource Plan of Northern States Power Company d/b/a Xcel Energy, and closes this docket.

2. The Commission finds that the current resource plan demonstrates Xcel's need for an additional 150 MW in 2017, increasing up to 500 MW in 2019.

3. Participants in Xcel's competitive resource acquisition process, Docket No. E-002/CN-12-1240, *In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy to Initiate a Competitive Resource Acquisition Process*, may propose a variety of resources to meet Xcel's need, including --

    a. Resources to address all or a portion of the identified need;

    b. Peaking resources, intermediate resources, or a combination of the two; and

    c. Resources that rely on new or existing generators.

4. In its next resource plan Xcel shall address, in addition to the issues set forth in the Commission's Order Establishing Procedural Schedules and Filing Requirements (November 30, 2012), the following issues:

[7] See, for example, Minn. Stat. §§ 216B.1691 (renewable energy standards), 216B.2422 (environmental externalities), 216H.02 (carbon dioxide regulations).

a. Solar Energy: Xcel shall report on the expected amount of solar energy on its system, barriers it sees to further solar deployment, and how solar development could contribute to peak demand management, economic development in Minnesota, and meeting Minnesota's renewable energy and environmental mandates and goals.

b. Demand Response: Xcel shall evaluate the potential capacity savings that Xcel could achieve via demand response programs, and the extent to which Xcel may rely on demand response in forecasting future need.

5. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

| | |
|---|---|
| Beverly Jones Heydinger | Chair |
| David C. Boyd | Commissioner |
| J. Dennis O'Brien | Commissioner |
| Phyllis A. Reha | Commissioner |
| Betsy Wergin | Commissioner |

In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan

ISSUE DATE: November 30, 2012

DOCKET NO. E-002/RP-10-825

ORDER ESTABLISHING PROCEDURAL SCHEDULES AND FILING REQUIREMENTS

## PROCEDURAL HISTORY

On August 2, 2010, Northern States Power Company d/b/a Xcel Energy (Xcel) filed a resource plan under Minn. Stat. § 216B.2422 and Minn. R. 7843.0400, subps. 1-4, covering the period 2011-2025.

Since March 31, 2011, the Commission has received written comments from the following:

- Calpine Corporation
- Campus Beyond Coal
- City of Mankato
- Dustin Dension, Applied Energy Innovations
- enXco
- Gerdau Ameristeel Corporation; Flint Hills Resources, LP; and USG Corporation
- Greater Mankato Growth
- Izaak Walton League of America – Midwest Office, Fresh Energy, Sierra Club, and the Minnesota Center for Environmental Advocacy, filing jointly (Environmental Intervenors)
- Minnesota Chamber of Commerce (the Chamber)
- Minnesota Department of Commerce (the Department)
- Prairie Island Indian Community
- Alan Muller
- Carol Overland
- Solar Power Manufactures of Minnesota
- Aladdin Solar, LLC; Applied Energy Innovations; Array Solar; Environment Minnesota; Institute for Local Self Reliance; Living Green Renewables; Minnesota Renewable Energy Society; Minnesota Solar Energy Industries Association; Donna and

Charlie Pickard; Powerfully Green; RREAL; Solar Connection, Inc.; Solar Farm, LLC; Sundial Solar; Sustology; Werner Electric Supply of Minnesota; Winona Renewable Energy, LLC, filing jointly

- University of Minnesota
- Members of the public, including members petitioning in support of solar power

On December 1, 2011, Xcel filed a revised resource plan. Among other things, Xcel proposed cancelling plans that would have added a net 450 megawatts (MW) of generating capacity to the Black Dog Generating Station (Black Dog).[1]

On February 8, 2012, Xcel filed corrections to its revised plan.

On June 1, 2012, Xcel proposed in a separate docket, contrary to its resource plan, to phase out Solar*Rewards, a program that subsidizes customer purchases and installation of photovoltaic solar cells.[2] The Department subsequently directed Xcel to maintain the Solar*Rewards program through 2015, albeit with a smaller incentive per watt.[3]

On August 13, 2012, Xcel filed reply comments further revising its resource plan. In particular --

- Xcel cited its 2012 Demand-Side Management Market Potential Assessment to support a lower estimate of the savings Xcel could achieve through influencing customer demand for electricity within its Minnesota service area.

- For this and other reasons, Xcel forecast that customer demand for electricity could exceed Xcel's supply by 2016.

- But Xcel proposed to add 400-600 MW of new capacity by 2017-2019 through soliciting proposals from outside parties as provided by Xcel's competitive resource acquisition process.

On October 22, 2012, in a separate docket, Xcel filed comments proposing to discontinue its plans for increasing the generating capacity of the Prairie Island Nuclear Generating Plant (Prairie Island Plant).[4] Because Xcel's resource plan reflected the assumption that Xcel would have the new capacity from the Prairie Island Plant, this filing effectively revised Xcel's resource plan further.

On October 25, 2012, the Commission received oral arguments from the parties and members of the public.

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[1] See Docket No. E-002/CN-11-184, *In the Matter of the Certificate of Need Application for the Black Dog Repowering Project in Burnsville, Minnesota.*

[2] See Docket No. E,G-002/CIP-12-447, *In the Matter of the Implementation of Northern States Power Company, a Minnesota Corporation's 2013/2014/2015 Triennial Natural Gas and Electric Conservation Improvement Program*.

[3] *Id*., Commerce Commissioner Decision (October 1, 2012), Ordering Paragraph 9.

[4] See Docket No. E-002/CN-08-509, *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*.

On November 1, 2012, the Commission met to consider the matter.

## FINDINGS AND CONCLUSIONS

### I. Summary

Because recent filings warrant further analysis, the Commission cannot act on Xcel's proposed resource plan at this time. Rather, the Commission establishes a schedule for further developing the record and resolving this docket.

The Commission also establishes schedules and content requirements for four additional filings: a competitive resource acquisition process, a fuel acquisition and risk management plan, a Life Cycle Management Study for Xcel's Sherburne County (Sherco) Generating Station Units 1 and 2, and Xcel's next resource plan.

### II. Resource Planning

To reliably provide the electricity demanded by its customers, an electric utility considers both supply and demand. The utility can supply electricity through a combination of generation and power purchases, and by reducing the amount of electricity lost through transmission and distribution. The utility can manage its customers' demand by encouraging customers to conserve electricity or to shift activities requiring electricity to periods when there is less demand on the electric system. A resource plan contains a set of demand- and supply-side resource options that the utility could use to meet the forecasted needs of retail customers.[5]

A public utility providing electricity to at least 10,000 customers and capable of generating 100,000 kilowatts of electricity must file a resource plan or report for the Commission's approval, rejection, or modification.[6] Generally, the resource planning statute and rules direct a utility to file biennial reports on the projected need for electricity in its service territory over the next 15 years; the utility's plans for meeting projected need, including a specific action plan for the next five years; the utility's analytical process to develop its plans; and the utility's reasons for selecting its preferred plan.[7] In addition, a resource plan should identify the likely effect the plan would have on electric rates and bills.

By integrating the evaluation of supply- and demand-side resource options – treating each resource as a potential substitute for the others – a utility can find the least-cost plan that is consistent with the other legal requirements and policies. These requirements and policies include the following:

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[5] Minn. Stat. § 216B.2422, subd. 1(d).

[6] Minn. Stat. § 216B.2422, subds. 1 and 4. The statute exempts federal power agencies, and the Commission's findings regarding service providers that are not statutory "public utilities" are merely advisory.

[7] Minn. Stat. § 216B.2422; Minn. R. Chap. 7843.

- Conservation: Minn. Stat. § 216B.241, subd. 1c(d), effectively requires utilities to reduce gross annual retail energy sales by at least one percent by promoting energy conservation and efficiency. And § 216B.2401 establishes a goal of achieving annual energy savings of 1.5 percent.

- Greenhouse Gas Regulation: Minn. Stat. § 216H.02 establishes a goal of reducing, relative to 2005, the emissions of greenhouse gasses by at least 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050. And § 216H.06 directs the Commission to estimate the cost of complying with future regulation of carbon dioxide ($CO_2$), a greenhouse gas, and to use this cost for purposes of evaluating resource alternatives. The Commission has approved a range of $9 to $34 per ton of $CO_2$ emitted in 2017 and thereafter.[8]

- Environmental Externalities: In addition to the $CO_2$ regulatory costs noted above, Minn. Stat. § 216B.2422, subd. 3, directs the Commission, "to the extent practicable, [to] quantify and establish a range of environmental costs associate with each method of electricity generation," and to use those costs for purposes of comparing resource alternatives.

- Renewable Energy Objectives/Renewable Energy Standards (REO-RES): Minn. Stat. § 216B.1691 directs Xcel to, among other things, use electricity from renewable sources to serve 30 percent of retail customer demand in Minnesota by 2030.[9] But in any given year if a utility acquires more electricity from renewable sources than it currently needs to meet the statutory requirements, subdivision 4(d) permits the utility to earn *renewable energy credits* (RECs) for the surplus. The utility may then use those credits to demonstrate compliance with the REO-RES in later periods, or sell credits to (or buy credits from) other utilities, subject to conditions.[10]

- Renewable Energy and Conservation Scenarios: In addition to the REO-RES, Minn. Stat. § 216B.2422, subd. 2, directs utilities to include in their resource plan filings the least-cost plan for meeting 50 percent of the need for any new or refurbished capacity through a combination of conservation and capacity powered by renewable sources of energy. The statute further directs utilities to include the least-cost plan for meeting 75 percent of this capacity with conservation and renewable energy resources.

- Distributed Generation: Minn. Stat. §§ 216B.169, 216B.243, 216B.1611, 216B.2411, and 216B.2426 encourage utilities to place greater reliance on acquiring electricity from

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[8] See *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06*, Docket No. E-999/CI-07-1199, Order Establishing 2012 and 2013 Estimate of Future Carbon Dioxide Regulation Costs (November 2, 2012).

[9] Minn. Stat. § 216B.1691, subd. 2b. Of the 30 percent in 2020, at least 25 percent must be generated from wind power.

[10] See *In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for RenewableEnergy Credits*, Docket No. E999/CI-04-1616, Order Approving Midwest Renewable Energy Tracking System (MRETS) under Minn. Stat. §216B.1691, Subd. 4(d), and Requiring Utilities to Participate in M-RETS (October 9,2007).

multiple smaller generators distributed throughout the utilities' service areas (distributed generation) and less reliance on large generators located far from customers.

- The Federal Production Tax Credit: A tax credit that subsidizes the generation of electricity from wind power will expire by the end of 2012 unless Congress renews it.[11]

- Federal Environmental Regulations: The federal Environmental Protection Agency (EPA) had adopted, and is continuing to develop, rules restricting various types of pollution. For example, the EPA recently adopted its Mercury and Air Toxics Standards and other policies designed to control the emissions of mercury (a neurotoxin), sulfur dioxide (a contributor to fine particulate pollution), and nitrogen oxides (a contributor to both particulates and ozone).[12] These policies may cause utilities to choose between retiring certain plants or installing new emissions-controlling equipment.

Finally, a utility not only has the duty to file a resource plan, it has the duty to inform the Commission and other parties of changed circumstances that "may significantly influence the selection of a resource plan."[13]

## III. Xcel's Resource Planning Process

In developing its resource plan, Xcel forecasts the amount of energy, and the amount of generating and transmission capacity, needed to meet customer needs. Xcel then evaluates how well its existing supply- and demand-side resources could meet those forecasted needs. On this basis, Xcel estimates its future resource needs – identifying the magnitude of new resources needed, and when those resources would be needed.

Xcel then selects a reference case or base case – that is, a set of supply- and demand-side resources to be evaluated, and against which to compare alternative combinations of supply- and demand-side resources. Using a computer model, Xcel then evaluates how well any given resource plan would perform under a variety of conditions, or scenarios. Xcel varies assumptions about the amount of customer demand; the amount of fuel costs; the cost of complying with environmental regulations, including $CO_2$ costs; and whether Congress extends the Production Tax Credit.

On this basis, Xcel selects a preferred resource plan. Xcel then subjects this preferred plan to more focused analyses before confirming its plan choice.

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[11] 26 U.S.C. § 45(d)(1).

[12] See, for example, National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial- Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 77 Fed. Reg. 9304 (Feb. 16, 2012), codified at 40 C.F.R. 60 *et seq*. (Mercury and Air Toxics Standards, or MATS).

[13] Minn. R. 7843.0500, subp. 5.

## IV. Xcel's Resource Plan and Five-Year Action Plan

Following its planning process, Xcel initially developed a five-year action plan in which Xcel proposed to do the following:

- Develop a plan to either update or replace Sherco Units 1 and 2, the two oldest coal-powered generators at Xcel's largest plant.
- Retire the coal-powered Units 3 and 4 at the Black Dog Generating Station, and replace their 270 MW of capacity with a new 700 MW natural gas unit in 2016.
- Add more generating capacity, or uprate, the Prairie Island Plant.
- Seek proposals for building up to 250 MW of wind-powered generation in the near term, and plan for an additional 400 MW between 2013-2016 and 500 MW between 2017-2020.
- Expand the amount of electricity it derives from solar power.
- Use demand-side management to reduce energy sales by 1.3 percent, and work with stakeholders to achieve a 1.5 percent reduction.

But Xcel subsequently revised its resource plan to reflect, among other things, slower-than-projected economic growth, a loss of wholesale customers, changes in Xcel's wind procurement strategy, reassements of Xcel's program for refurbishing Black Dog Units 3 and 4 and the Prairie Island Plant, and the anticipated expiration of the Production Tax Credit. Xcel has revised its five-year action plan and now proposes to do the following:

- Continue developing plans to either update or replace Sherco Units 1 and 2.
- Retire Black Dog Units 1 and 2, but cancel plans to acquire replacement power.
- Reassess the need to complete the uprate of the Prairie Island Plant.
- Reassess the need for more wind-powered electricity.
- Continue its Solar*Rewards program, but with lower subsidies for enrollees.
- Continue to use demand-side management to reduce energy sales by 1.3 percent, and work with stakeholders to achieve a 1.5 percent reduction in the near term, but anticipate reduced savings in the future as Xcel depletes the most cost-effective opportunities for load management and conservation.

While Xcel's initial filing incorporated $CO_2$ costs into its base case, its revised filings excluded $CO_2$ costs from the base case. Xcel did, however, consider scenarios that included a range of $CO_2$ costs.

Based on its new analysis, Xcel now projects that its current supply- and demand-side resources will be sufficient to meet customers' forecasted needs until 2017. Xcel concludes that between 2017 and 2019 it will need to add 400-600 MW of generating capacity – and perhaps more, to offset the capacity that Xcel no longer proposes to add to its Prairie Island Plant.

## V. Commission Analysis and Action

### A. Xcel's Resource Plan

Parties offer various recommendations about whether the Commission should approve, reject, or modify Xcel's resource plan, including its five-year action plan. The Department, among others, argues that the parties have not had sufficient opportunity to review the multiple changes Xcel has filed. The Department argues, and Xcel agrees, that the Commission's judgment would benefit from additional analysis.

The Commission concurs; the latest developments in Xcel's resource plan require further analysis. Consequently the Commission will decline to act on Xcel's resource plan at this time. Instead, the Commission will direct parties to continue analyzing and developing a resource plan for Xcel – and in particular, to develop the base level of Xcel's resource needs sufficiently to enable the Commission to identify the size, type, and timing of any new resources required.

To this end, the Commission will establish a schedule by which the Department and Xcel must file their analyses based on their revised computer models – incorporating, for example, any changed assumptions regarding the Prairie Island Plant's generating capacity. Other parties will be free to file comments at that time as well. The Commission will receive a final round of comments thereafter.

These steps will provide a suitable foundation for the Commission to render its findings on Xcel's resource plan and close the docket.

### B. Additional filings

While the record is not yet sufficient to permit the Commission to act on Xcel's resource plan, it is sufficient to demonstrate the need for further analyses – including analyses that will extend beyond the scope of the current docket. Consequently the Commission will direct Xcel to make three additional filings.

#### 1. Competitive Resource Acquisition Process

Statute authorizes Xcel to invite outside parties to propose means by which Xcel should meet its resource needs.[14] Xcel has established a process for doing so.[15] Under this process when Xcel identifies the need for substantial new sources of generation, Xcel prepares a plan for notifying

[14] Minn. Stat. § 216B.2422. subd. 5.

[15] See generally *In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2005 - 2019 Resource Plan*, Docket No. E-002/RP-04-1752.

potential resource providers – developers of electric generators, for example -- of the opportunity to file proposals for meeting the need.[16]

While aspects of Xcel's resource plan remain unresolved, it is clear that Xcel will need to acquire additional resources to meet customer need. Consequently the Commission will direct Xcel to prepare and file a notice plan for soliciting proposals from outside parties.[17] This filing will coincide with the deadline for parties to file reply comments on Xcel's resource plan.

### 2. Fuel Acquisition and Risk Management Plan

The Commission will direct Xcel to file by July 1, 2013, a fuel acquisition and risk management plan. Xcel already files an annual fuel procurement plan.[18] But as the Chamber notes, and Xcel acknowledges, Xcel's preferred plan relies heavily on generating electricity with natural gas, a fuel with a history of price volatility. This fact prompts the Chamber to recommend that the Commission direct Xcel to solicit proposals for a 20-year fixed price contract for gas. While that proposal is premature, the Commission finds that the record demonstrates the need for Xcel to explore in greater depth the fuel price risks of its proposed resource plan, and the opportunities and terms available for long-term supply contracts to mitigate those risks.

### 3. Life Cycle Management Study for Sherco Units 1 and 2

The Commission will direct Xcel to evaluate how best to manage the two oldest generators at its largest power plant, Sherco Units 1 and 2, over the rest of the generators' useful lives. Xcel states that it plans to complete a Life Cycle Management Study for Units 1 and 2 by July 1, 2013, but notes that the scope of the study is still evolving. As part of that study, the Commission will direct Xcel to examine the feasibility and cost-effectiveness of continuing to operate, retrofitting, or retiring these generators, and to file a report which includes the following items:

a. An analysis of how the cessation of operations at either of the two oldest Sherco generators – whether due to retirement or to install new emissions controls – would affect the reliability of Xcel's entire system.

[16] See, for example, *id.*, Order After Reconsideration Clarifying Filing Requirements, Requiring Notice to Alternative Providers, Setting Deadline for Baseload Proposals, and Accepting Reports (October 18, 2006) at 4-5.

[17] See *In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy to Initiate a Competitive Resource Acquisition Process*, Docket No. E-002/CN-12-1240, Order Closing Docket, Establishing New Docket, and Schedule for Competitive Resource Acquisition Process (November 21, 2012).

[18] See, for example, E-002/M-02-633, *In the Matter of Northern States Power Company d/b/a Xcel Energy Inc. Petition For Approval of its 2012 Emissions Reduction Project Revenue Requirement and Tracker Balance Report*.

b. Specific estimates of the cost to install and operate equipment for controlling power plant emissions, and other required investments.

c. A base case that accounts for all likely EPA regulations, as well as the values this Commission has established for environmental externalities and $CO_2$ regulatory costs.

d. Consideration of a wide range of scenarios, including --

- A range of updated externality values – not merely those adopted by this Commission, but those used by the federal government for regulatory impact analyses;

- A wide range of fuel prices;

- Least-cost scenarios to reduce greenhouse gasses relative to 2005 levels by at least 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050;

- A least-cost plan for replacing 50 percent of the capacity of Sherco Units 1 and 2 through a combination of conservation and capacity powered by renewable sources of energy; and

- A least-cost plan for replacing 75 percent of the capacity of Sherco Units 1 and 2 through a combination of conservation and capacity powered by renewable sources of energy.

As this report is prepared, interested parties must have the opportunity to intervene, conduct discovery, and provide comment. Participation by interested and knowledgeable parties will help ensure that the broadest range of factors is considered.

### C. Xcel's Next Resource Plan

Consistent with the request of various parties, the Commission finds it reasonable to set the date for Xcel's next resource plan filing at February 1, 2014. This should provide Xcel with sufficient time to analyze the relevant issues, and to prepare the filing in the manner prescribed by the Legislature and the Commission. In particular, the Commission will direct Xcel to include the following items:

First, Xcel should include scenarios exploring whether Xcel can achieve higher levels of cost-effective and feasible demand response, as recommended by parties ranging from the Chamber to the Environmental Intervenors. Demand response programs are designed to reduce the consumption of electricity during periods of high system usage. The percentage of customers that participate in these programs varies from utility to utility. Xcel's current plan assumes that Xcel will continue to enroll customers into these programs at its current rate. But the Environmental Intervenors cite Xcel's 2012 Demand-Side Management Market Potential Assessment for the proposition that Xcel could, with reasonable effort, achieve participation rates in these programs that would be among the top 25 percent in the nation. This strategy may help Xcel meet customer demand – especially in 2017-2019, when Xcel anticipates needing additional resources.

Second, Xcel should include a reevaluation of its decision to acquire new sources of wind-powered electricity. Xcel had initially proposed to add 100 MW of wind-powered generation in 2015 or 2016, but is now reconsidering this plan. The Chamber opposes the purchase of new wind power as uneconomic in the current environment, whereas the Department's analysis still favors the acquisition of more wind power in that timeframe. The Commission notes that Xcel's current portfolio of wind-powered generators and renewable energy credits mean that Xcel currently has no regulatory compliance need for more electricity from wind power. And given the uncertainty surrounding greenhouse gas regulations and the extension of the federal production tax credits, the Commission finds that Xcel is justified in reconsidering its wind power acquisition strategy.

Third, Xcel should evaluate the costs, benefits, and effects of including higher levels of distributed generation. The Chamber recommends that Xcel evaluate industrial-sized distributed generation and generators that produce both power and heating. The Environmental Intervenors recommend that Xcel evaluate utility-scale solar power. The Commission concurs on both counts. Distributed generation has the prospect of increasing system reliability, reducing transmission congestion, exploiting efficiencies through coordination with customer-owned facilities, and reducing emissions. Larger distributed generation projects hold the possibility of achieving these benefits combined with economies of scale.

Fourth, Xcel should include a comprehensive section on all EPA rules that may affect Xcel's operations. Recent changes may have substantial consequences for Xcel's resource choices.

Finally, Xcel should comply with the various requirements for resource plans. For planning purposes, Xcel should develop its base case scenario assuming that Xcel will incur $9 to $34 per ton of $CO_2$ emitted, beginning in 2017. Xcel omitted this factor from the base case of its revised resource plan. While this choice did not alter the results of Xcel's analysis in this case, prospectively the Commission expects Xcel to incorporate these regulatory costs into its base case for purposes of comparing potential resources.

Similarly, Xcel should comply with the requirements of Minn. Stat. § 216B.2422 to include least-cost 50 percent and 75 percent renewables and conservation scenarios for all new and refurbished capacity. Xcel should provide least-cost scenarios to reduce greenhouse gasses relative to 2005 levels by at least 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050, consistent with the state's greenhouse gas goals set forth in Minn. Stat. § 216H.02.

And, as noted above, Minn. R. 7843.0400, subp. 4, requires a resource plan to identify the likely effect on electric rates and bills if the utility implements its preferred plan. The Commission expects Xcel to work with interested parties on identifying useful ways to measure these likely effects on rates and bills, and to incorporate these measures into Xcel's resource plan filing.

## ORDER

1. With respect to the current docket, the Commission establishes the following procedural schedule:

- December 18, 2012: Deadline to file comments. The Department and Xcel shall file any final revisions to their models and analysis.

- January 16, 2013: Deadline to file reply comments.

- February 2013: Commission action and docket closure.

2. By January 16, 2013, Xcel shall file a notice plan for soliciting bids as part of Xcel's competitive resource acquisition process, as provided in *In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy to Initiate a Competitive Resource Acquisition Process*, Docket No. E-002/CN-12-1240, Order Closing Docket, Establishing New Docket, and Schedule for Competitive Resource Acquisition Process (November 21, 2012).

3. By July 1, 2013, Xcel shall file a fuel acquisition and risk management plan.

4. By July 1, 2013, Xcel shall submit a Sherco Life Cycle Management Study that examines the feasibility and cost-effectiveness of continuing to operate, retrofitting, or retiring Sherburne County (Sherco) Generating Station Units 1 and 2. Procedurally, interested parties shall have the opportunity to intervene, conduct discovery, and comment. Substantively, the study shall include --

   A. Specific cost estimates of controls and other required investments.

   B. An analysis of how a temporary or permanent outage at either Sherco Units 1 or 2 would affect system reliability.

   C. A base case that includes Commission-adopted carbon dioxide ($CO_2$) costs and externality values.

   D. A base case that accounts for all likely federal Environmental Protection Agency (EPA) regulations.

   E. Analysis of scenarios that include the following:

      - A range of updated externality values based on those used by this Commission and the federal government for regulatory impact analyses.

      - A wide range of fuel prices.

      - Least-cost scenarios to reduce greenhouse gasses relative to 2005 levels by at least 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050.

      - A least-cost plan for replacing 50 percent of the capacity of Sherco Units 1 and 2 through a combination of conservation and capacity powered by renewable sources of energy

- A least-cost plan for replacing 75 percent of the capacity of Sherco Units 1 and 2 through a combination of conservation and capacity powered by renewable sources of energy.

5. By February 1, 2014, Xcel shall file its next resource plan.

   A. In preparing this plan, Xcel shall do the following:

   - Consider the goal of achieving participation rates for demand response programs in the top 25 percent of such programs nationwide, as addressed in Xcel's 2012 Demand-Side Management Market Potential Assessment, to help meet projected demand in the 2017-2019 timeframe.

   - Reassess acquiring new wind generation for the 2015-2016 timeframe.

   - Evaluate the costs, benefits, and effects of including higher levels of distributed generation, including industrial-sized distributed generation, utility-scale solar, and combined heat and power.

   - Work with interested parties to identify useful ways to estimate how implementing Xcel's preferred resource plan would affect customer rates and bills, and incorporate those estimates into the resource plan filing.

   B. In the plan, Xcel shall include the following:

   - Scenarios that evaluate higher levels of cost-effective and feasible demand response capability.

   - A base case with $CO_2$ values consistent with the Commission-approved range of $9 to $34 per ton beginning in 2017.

   - Least-cost scenarios to reduce greenhouse gasses relative to 2005 levels by at least 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050.

   - An assessment of Xcel's prospects for acquiring more electricity generated by wind power.

   - A least-cost scenario for meeting 50 percent of the need for any new or refurbished capacity through a combination of conservation and capacity powered by renewable energy, and a least-cost scenario for meeting 75 percent of this need through conservation and renewable sources, consistent with Minn. Stat. § 216B.2422.

   - A comprehensive section on all EPA rules which may affect Xcel's operations.

6. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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|---|---|
| Beverly Jones Heydinger | Chair |
| David C. Boyd | Commissioner |
| Nancy Lange | Commissioner |
| J. Dennis O'Brien | Commissioner |
| Betsy Wergin | Commissioner |

In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process

ISSUE DATE: March 5, 2013

DOCKET NO. E-002/CN-12-1240

ORDER EXTENDING BIDDING DEADLINE AND REFINING PROCEDURAL FRAMEWORK

## **PROCEDURAL HISTORY**

On November 21, 2012, the Commission issued an order opening this docket to manage the process of selecting the additional resources Northern States Power Company d/b/a Xcel Energy needs to meet the projected needs of its service area between now and 2020.[1]

Xcel secures new resources through a competitive bidding process, as permitted under Minn. Stat. § 216B.2422, subd. 5. In this case the Company intends to compete in the bidding process itself, which means that it must submit a detailed proposal to be weighed against competing proposals in a formal evidentiary proceeding based on the certificate of need statute and rules.[2]

The November 21 order deferred action on requests for additional procedural guidance on the certificate-of-need-based proceeding, urging the parties to seek procedural agreement where possible. The order also required the Company to file a plan for notifying potential bidders of the competitive bidding process.

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[1] Order Closing Docket, Establishing New Docket and Schedule for Competitive Resource Acquisition Process, issued in this docket and in docket E-002/CN-11-184, *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for Approximately 450 MW of Incremental Capacity for the Black Dog Generating Plant Repowering Project*.

[2] The Company's competitive resource acquisition process was established in its 2004 resource plan proceeding, *In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2004 Resource Plan*, E-002/RP-04-1752, Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, subd. 5, and Requiring Compliance Filing (May 31, 2006).

On January 30, 2013, the Commission issued an order approving a notice plan for the competitive bidding process. Among other things, that order required the Company to maintain a website with detailed, updated information for potential bidders.

On February 20, 2013, the Commission met to consider providing additional procedural guidance as the competitive bidding process moves forward. The following parties filed comments on the procedural framework to be used in this case:

- Xcel Energy (Xcel or the Company)
- Minnesota Department of Commerce (Department)
- Calpine Corporation
- Izaak Walton League of America – Midwest Office, Fresh Energy, Sierra Club, and Minnesota Center for Environmental Advocacy, filing jointly ("Environmental Intervenors")
- Flint Hills Resources, L.P.; Gerdau Ameristeel Corporation; and USG Interiors, Inc.; filing jointly ("Xcel Large Industrials")

## FINDINGS AND CONCLUSIONS

### I. The Issues

The parties' comments focused on five issues:

- *Should the Commission appoint an independent evaluator to assist the Administrative Law Judge who will conduct the evidentiary phase of this contested case proceeding?*

- *Should trade secret data be discoverable, and if so, by whom, and subject to what safeguards?*

- *To what extent should bidders be bound by the cost information they file?*

- *To what extent do substantive certificate-of-need criteria apply in this case?*

- *Should the March 18 bidding deadline be extended?*

These issues will be examined in turn.

### II. Independent Evaluator

Calpine Corporation, a large independent power producer that intends to bid in this resource acquisition process, urged the Commission to appoint an independent evaluator to screen all bids, weigh them against one another, and render a report and recommendation to the Administrative Law Judge. Calpine argued that appointing an independent evaluator would make the evidentiary process more efficient and would reduce or eliminate the need for bidders to disclose trade secret information to one another. Instead, they could submit protected information to the independent evaluator alone.

Calpine recommended appointing the Department to serve in this role, citing its objectivity and its detailed knowledge of resource planning, Xcel's service area, and Xcel's generation and transmission systems. The Department was willing to serve, but pointed out that it would conduct the same exhaustive analysis of all bids whether it was designated an independent evaluator or not.

None of the other parties objected to asking the Department to serve as an independent evaluator, although Xcel argued that it would still need some access to other bidders' protected information, both to meet its due-diligence obligations and to enable it to properly assist in analyzing the compatibility of individual proposals with the Company's system.

The Commission sees no current advantage to appointing an independent evaluator. The Department's analysis will be exhaustive with or without that designation, and it is unclear that appointing an independent evaluator would substantially reduce the need to exchange sensitive information or the number and intensity of disputes that that need generates. The Commission will therefore decline to appoint an independent evaluator at this time.

The Commission notes, however, that the Administrative Law Judge hearing this case will have full authority to seek the assistance of an independent evaluator, will be in the best position to determine whether an independent evaluator would be helpful, and should promptly appoint one if that is the case.

## III. Trade Secret Data

Xcel and Calpine have been attempting to negotiate a non-disclosure agreement governing the treatment of trade secret and other privileged or sensitive information they may divulge to one another. They had not succeeded as of the date of the Commission meeting, when their baseline positions were as follows.

Calpine recommended that competing bidders share no confidential information with one another. Xcel concurred in part, but argued that other bidders' confidential information must go to its "resource planning employees." Both parties agreed to full disclosure to the Commission, the Department, and the Administrative Law Judge.

This issue, too, is best resolved by the Administrative Law Judge as the case develops. He or she will be in the best position to determine what level of disclosure among competing bidders is required to ensure due process and fundamental fairness, as well as what level of protection must accompany that disclosure. The Commission will therefore recommend that the Administrative Law Judge begin by requiring full disclosure to all utility regulatory agencies and independent evaluators and follow up as necessary by permitting disclosure under appropriate non-disclosure agreements and requiring disclosure under discovery orders issued on appropriate motions.

## IV. Consequences of Submitting Cost Data

Calpine contended that all bidders, including Xcel, should submit fixed-price bids, without recourse to recovering cost overruns from ratepayers. Xcel countered that as a public utility its costs are reviewed for reasonableness and prudence, it cannot retain margins exceeding levels the Commission finds reasonable, and it should not be required to sustain losses due to excess costs the

Commission might find reasonable. Xcel also stated that it was considering submitting a proposal that featured a mechanism for sharing gains and losses between ratepayers and shareholders.

Reliable information is clearly critical to a fair bidding process and a least-cost outcome. All bidders should be held to the cost information provided in their bids, which the Commission will evaluate in the course of this contested case proceeding.

## V. Application of Certificate-of-Need Criteria

The Environmental Intervenors asked the Commission to make an explicit finding that using the competitive bidding process does not excuse Xcel from statutory requirements to show that any demonstrated need could not be met as cost-effectively by demand-side management or renewable generation as by non-renewable generation. The Commission will take no action on this issue, since it evoked no controversy and the statutes speak for themselves.

## VI. Bidding Deadline

The Xcel Large Industrials urged the Commission to extend the bidding deadline from the March 18 date set in the November 21 order to June 1. The Large Industrials argued that the shorter time frame might be inadequate to ensure that all potential bidders have the opportunity to compete in this resource selection process. They noted that, in Xcel's compliance filing to the May 31, 2006 order establishing this process, the company set a 90-day time frame for submitting bids.

The Department and Xcel both argued that a June 1 deadline would place ratepayers at risk of not having new resources available when first needed in 2017, jeopardizing reliability and affordability. They also stated that as a practical matter, vendors likely to participate in this resource acquisition process were few, were aware of Xcel's anticipated resource shortfall, and were aware of this proceeding.

The Commission concurs with the Large Industrials on the importance of ensuring adequate time for all potential bidders to prepare their proposals and concurs with the Department and Xcel on the importance of ensuring that adequate, cost-effective resources are in place when needed. The Commission will therefore extend the bidding deadline by approximately a month – to April 15 – to serve both objectives.

This extension will expand the time for bid preparation without jeopardizing the thoroughness of the contested case to follow. Further, news of this extension will be disseminated immediately on the Company's resource acquisition website, which it updates in real time under Commission order.[3]

## ORDER

1. The Commission declines to appoint an independent evaluator, noting that the Administrative Law Judge hearing this case will have the right to request the assistance of an independent evaluator if desired.

[3] Order Approving Notice Plan, this docket, January 30, 2013.

2. The Commission recommends that the Administrative Law Judge assigned to this case treat confidential and proprietary information as follows: All confidential and proprietary information shall be presented to the Department, the Commission, the Office of Administrative Hearings, the Office of the Attorney General, and any independent evaluators used during the process. Either upon agreement of parties to a non-disclosure agreement or upon Motion to the ALJ, the ALJ may allow disclosure to another party.

3. All parties will be held to the cost information provided in their bids.

4. The March 18, 2013 bidding deadline set in the Commission's November 21, 2012 order in this docket is hereby extended to April 15, 2013.

5. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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|---|---|
| Beverly Jones Heydinger | Chair |
| David C. Boyd | Commissioner |
| J. Dennis O'Brien | Commissioner |
| Phyllis A. Reha | Commissioner |
| Betsy Wergin | Commissioner |

In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for Approximately 450MW of Incremental Capacity for the Black Dog Generating Plant Repowering Project

In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy to Initiate a Competitive Resource Acquisition Process

ISSUE DATE: November 21, 2012

DOCKET NO. E-002/CN-11-184
DOCKET NO. E-002/CN-12-1240

ORDER CLOSING DOCKET, ESTABLISHING NEW DOCKET, AND SCHEDULE FOR COMPETITIVE RESOURCE ACQUISITION PROCESS

## PROCEDURAL HISTORY

On March 15, 2011, Northern States Power Company d/b/a Xcel Energy (Xcel or the Company) filed a petition for a Certificate of Need for its Black Dog Generating Plant Repowering Project. At the time the Company anticipated the project would provide resources needed to address a projected generation deficit starting in 2014.

On August 19, 2011, after Calpine Corporation (Calpine) petitioned to intervene in the Black Dog certificate of need proceeding with an alternative proposal, the Commission determined it could not resolve all questions regarding the prudence of the Xcel and Calpine proposals. The Commission referred the Black Dog certificate of need proceeding to the Office of Administrative Hearings (OAH) for contested case proceedings.

On December 7, 2011, Xcel moved in the OAH proceeding to have the matter certified to the Commission for consideration of the Company's desire to withdraw its certificate of need application. Calpine and the Minnesota Department of Commerce (the Department) opposed the Motion. Xcel also requested that the Commission close the site and route permit application docket.

On May 30, 2012, Administrative Law Judge Richard C. Luis certified to the Commission Xcel's motion to withdraw its certificate of need application.

The Commission initiated a comment period and received comments from the Department, Xcel, and Calpine.

On October 25, 2012, the Commission heard oral arguments on the Company's requests to withdraw its Black Dog Project certificate of need and site and route permit applications, along with Xcel's 2011 – 2025 Integrated Resource Plan.[1] The Commission requested that the parties file revised proposals for Commission action, and Xcel, Calpine, and the Department did so.

On November 1, 2012, the Commission met to deliberate.

## FINDINGS AND CONCLUSIONS

### I. Background

At issue is whether Xcel should be permitted to withdraw its application for a certificate of need for its Black Dog Generating Plant repowering project.

This matter comes before the Commission having been certified by the Administrative Law Judge presiding over contested case proceedings initiated by Commission order.[2] Because the matters are closely interrelated, the Commission considers Xcel's withdrawal request in conjunction with the Company's related request in the Black Dog site and route permit application docket (E-002/CN-11-307), Xcel's 2011 – 2025 Integrated Resource Plan (E-002/RP-10-825), and its request to discontinue its plan to increase generating capacity at its Prairie Island Nuclear Plant (E-002/CN-08-509) (the related dockets).

By the time the Commission met to deliberate the issues in these dockets, the parties acknowledged that developments in the related dockets suggested that the size, type, and timing of Xcel's capacity needs should be revisited. These developments include updated demand forecasts, costs of alternative resource options, and Xcel's disinclination to continue the Prairie Island power uprate project.

Additional modeling to be filed and commented upon in the resource plan docket may justify revising the size, type, and timing of Xcel's resource need. In a separate order in the resource plan docket, the Commission will defer action on the Company's resource plan and establish a schedule for further developing Xcel's five-year action plan. The Commission anticipates determining Xcel's resource need in February 2013.[3]

The changed circumstance of Xcel's anticipated resource need leaves Xcel's and Calpine's proposals in Docket. No. E-002/CN-11-184 in need of revision. Accordingly, the parties offered a number of procedural suggestions to facilitate addressing Xcel's need, once it is established in the resource plan docket. The suggestions were refined and revised after the initial meeting at which the Commission heard oral arguments on the related dockets.

### II. Positions of the Parties

The revised suggestions of the parties reflect agreement that once the size, type, and timing of Xcel's resource need is determined, the need should be addressed through a competitive resource acquisition process. The Department and Calpine initially recommended revising the scope of

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[1] *In the Matter of Xcel Energy's 2011 – 2025 Integrated Resource Plan*, Docket No. E-002/RP-10-825.

[2] Notice and Order for Hearing (August 19, 2011).

[3] A more detailed schedule will be established by separate order in Docket. No. E-002/RP-10-825.

Docket No. E-002/CN-11-184 to accommodate that process. During Commission deliberations, the Department stated it viewed opening a new docket as a workable alternative.

Additionally, Calpine requests that the Commission establish certain details of the competitive resource acquisition process. Calpine recommends that the Commission request that the Department act as an independent evaluator of the anticipated resource proposals, a recommendation that the Department is amenable to. Calpine also recommends that the Commission establish an approach for protecting trade secret information. Xcel contends that no independent evaluator is necessary, and recommends that the Commission take no action on the trade secret issue.

## III. Commission Action

In order to identify Xcel's resource need, solicit and evaluate project proposals, and ultimately have those projects online and meeting identified need, time is of the essence. The Commission will order a competitive resource acquisition process be undertaken in a new docket (E-002/CN-12-1240) with a schedule that overlaps the schedule for developing Xcel's five-year action plan as ordered in the resource planning docket. This schedule will facilitate the process of securing needed generation resources in a timely fashion.

The schedule is as follows (bolded items indicate filing deadlines):

| Deadline | Action |
|---|---|
| **December 2012 – January 2013** | **Xcel to file Notice Plan for Certificate of Need** |
| February 2013 | Commission finding concerning Xcel's resource need in resource planning docket (E-002/RP-10-825). |
| **March 18, 2013** | **Xcel and other interested competitors' resource proposals to meet identified need shall be filed in Docket No. E-002/CN-12-1240.** |
| April 2013 | Commission determines completeness of proposals, refers matter to OAH if warranted. |
| September – October 2013 | ALJ Report, if referred to OAH. |
| October – November 2013 | Commission decision on competitive resource acquisition process. |

Xcel will be required to begin the process by filing a notice plan for the competitive resource acquisition process no later than January 31, 2013, and earlier if possible. Because size, type, and timing of the required resources will not have yet been established, they should not be specified in the notice.

After the Commission has determined Xcel's resource need in the resource planning docket, which is anticipated to occur in February, 2013, Xcel, Calpine, and other parties interested in participating must file proposals to meet the identified need by March 18, 2013, in the new competitive resource acquisition docket (E-002/CN-12-1240). The Commission will then consider the proposals and make its final determination no later than November 2013.

At this time, the Commission will not establish details of the competitive resource acquisition process such as whether to request the Department to act as an independent evaluator, or establish a particular approach to protect trade secret information. It is premature to act on these issues, and the parties may resolve any outstanding concerns about the treatment of trade secret information without need for Commission action.

## <u>ORDER</u>

1. Docket No. E-002/CN-11-184 is hereby closed.
2. Docket No. E-002/CN-12-1240, *In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy to Initiate a Competitive Resource Acquisition Process*, is established to address the resource needs to be identified in Xcel's Integrated Resource Plan (Docket No. E-002/RP-10-825), with administrative notice taken of the filings in Docket No. E-002/CN-11-184.
3. No later than January 31, 2013, Xcel shall file in Docket No. E-002/CN-12-1240 a notice plan for a competitive resource acquisition process.
4. No later than March 18, 2013, resource proposals from interested parties shall be filed in Docket No. E-002/CN-12-1240.
5. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

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**Appendix F**
**Completeness Checklist**

| Authority | Required Information | Location in Application |
|---|---|---|
| Minn. R. 7849.0200, Subp. 4 | Cover Letter | First Page |
| Minn. R. 7829.2500, Subp. 2 | Brief summary of filing on separate page sufficient to apprise potentially interested parties of its nature and general content | After Cover Letter |
| Minn. R. 7849.0200, Subp. 2 | Title Page and Table of Contents | Pages i - v |
| Minn. R. 7849.0240 | Need Summary and Additional Considerations | |
| Subp. 1 | Summary of the major factors that justify the need for the proposed facility | Sections 1.1.2, 1.3, 1.6, 1.7, 3, and 5.2 – 5.6 |
| Subp. 2 | Relationship of the proposed facility to the following socioeconomic considerations: | |
| A. | Socially beneficial uses of the output of the facility; | Section 1.1.2 and 1.7 |
| B. | Promotional activities that may have given rise to the demand for the facility; and | Appendix B |
| C. | Effects of the facility in inducing future development. | Sections 1.7 and 3 |
| Minn. R. 7849.0250 | Proposed LEGF and Alternatives | |
| A. | A description of the facility, including: | |
| (1) | Nominal generating capability of the facility, and discussion of economies of scale on facility size and timing; | Sections 4.2, 4.3, 5.2; Appendix C, Tables C4a and C4b |
| (2) | Description of anticipated operating cycle, including expected annual capacity factor; | Appendix C, Tables C4a and C4b |

**Appendix F**
**Completeness Checklist**

| Authority | Required Information | Location in Application |
|---|---|---|
| (3) | Type of fuel used, including the reason for the choice, its projected availability over the facility's life, and alternate fuels, if any; | Sections 4.2 and 4.3 |
| (4) | Anticipated heat rate of the facility; and | Appendix C, Tables C1a and C1b |
| (5) | To fullest extent known to applicant, the anticipated area(s) the facility could be located; | Sections 1.4.1, 1.4.2, 1.5, 4.2, 4.3 and 6.9 |
| B. | Discussion of available alternatives, including: | |
| (1) | Purchased power; | Section 5.3 |
| (2) | Increased efficiency of existing facilities, including transmission lines; | Section 5.5 |
| (3) | New transmission lines; | Section 5.6 |
| (4) | New generating facilities of different size or using different energy sources; and | Sections 1.6, 5.2 and 5.4 |
| (5) | Any reasonable combination of the above; | Sections 5.2 – 5.6 |
| C. | For proposed facility and alternatives discussed in item (B) that could provide electric power to meet the identified need: | |
| (1) | Capacity cost/kW in current dollars; | Appendix C, Tables C3a and C3b |
| (2) | Service life; | Appendix C, Tables C4a and C4b |
| (3) | Estimated average annual availability; | Appendix C, Tables C4a and C4b |
| (4) | Fuel costs/kWh in current dollars; | Appendix C, Tables C3a and C3b |

**Appendix F**
**Completeness Checklist**

| Authority | Required Information | Location in Application |
|---|---|---|
| (5) | Variable O&M costs/kWh in current dollars; | Appendix C, Tables C3a and C3b |
| (6) | Total cost of a kWh generated in current dollars; | Appendix C, Tables C3a and C3b |
| (7) | Estimate of effect on rates systemwide and Minnesota, assuming a test year beginning with in-service date; | Appendix C, Tables C3a and C3b |
| (8) | Estimated heat rate; and | Appendix C, Tables C1a and C1b |
| (9) | Major assumptions for subitems (1)–(8), including projected escalation rates for fuel and O&M, and project capacity factors; | Appendix C |
| D. | A map showing applicant's system; and | Section 2.2 |
| E. | Other information about the facility and alternatives relevant to determination of need. | Chapters 4 and 5 |
| Minn. R. 7849.0270 | Peak Demand and Annual Consumption Forecasts | |
| Subp. 1 | Peak demand and annual consumption data for applicant's service area and system, indicating when data is not available, historical, or projected; | Appendix A |
| Subp. 2 | The following data fo each forecast year: | |
| A. | Annual consumption by ultimate consumers within applicant's Minnesota service area; | Appendix A |
| B. | Estimates of total ultimate consumers and their annual consumption for each of the following consumer categories: | |
| (1) | Farm; | Appendix A |
| (2) | Irrigation and drainage pumping; | Appendix A |

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| Authority | Required Information | Location in Application |
|---|---|---|
| (3) | Nonfarm residential; | Appendix A |
| (4) | Commercial; | Appendix A |
| (5) | Mining; | Appendix A |
| (6) | Industrial; | Appendix A |
| (7) | Street and highway lighting; | Appendix A |
| (8) | Transportation; | Appendix A |
| (9) | Other (including municipal water pumping, oil/gas pipeline pumping, military, all other consumers not reported in subitems (1)-(8)); and | Appendix A |
| (10) | Sum of subitems (1)-(9); | Appendix A |
| C. | Estimate of demand on applicant's system at time of annual system peak demand, including breakdown of demand into consumer categories in item B; | Appendix A |
| D. | Applicant's system peak demand by month; | Appendix A |
| E. | Estimated annual revenue requirement/kWh for system in current dollars; and | Appendix A |
| F. | Applicant's estimated average system weekday load factor by month; | Appendix A |
| Subp. 3 | Detail of forecast methodolgy employed, including | |
| A. | Overall methodological framework that is used; | Appendix A |

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| Authority | Required Information | Location in Application |
|---|---|---|
| B. | Specific analytical techniques used, their purpose, and components to which they were applied; | Appendix A |
| C. | Manner in which specific techniques relate to forecast; | Appendix A |
| D. | Where statistical techniques have been used: | |
| (1) | Purpose of technique; | Appendix A |
| (2) | Typical computations, specifying variables and data; and | Appendix A |
| (3) | Results of appropriate statistical tests; | Appendix A |
| E. | Forecast confidence levels/ranges of accuracy for annual peak demand and consumption, and description of their derivation; | Appendix A |
| F. | Brief analysis of methodology used, including: | |
| (1) | Strengths and weaknesses; | Appendix A |
| (2) | Suitability to the system; | Appendix A |
| (3) | Cost considerations; | Appendix A |
| (4) | Data requirements; | Appendix A |
| (5) | Past accuracy; and | Appendix A |
| (6) | Other significant factors; | Appendix A |

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| Authority | Required Information | Location in Application |
|---|---|---|
| G. | Explanation of discrepancies between application's forecast and applicant forecasts in other proceedings; | Chapter 3<br>Appendix A |
| Subp. 4 | Data base used in forecast, including: | |
| A. | Complete list of all data used in forecast, including a brief description of each and how it was obtained; | Appendix A |
| B. | Clear identification of any adjustments to raw data to adapt them for use in forecasting, including: | |
| (1) | Nature of adjustment; | Appendix A |
| (2) | Reason for adjustment; and | Appendix A |
| (3) | Magnitude of adjustment | Appendix A |
| Subp 5 | Essential forecast assumptions made regarding: | |
| A. | Availability of alternate sources of energy; | Appendix A |
| B. | Expected conversion from other fuels to electricity or vice versa; | Appendix A |
| C. | Future electricity prices in applicant's system and their effect on system demand; | Appendix A |
| D. | Subpart 2 data that is not available historically nor created by applicant for forecast; | Appendix A |
| E. | Effect of conservation programs on long-term demand; and | Appendix A |
| F. | Any factor considered in preparing forecast; | Appendix A |
| Subp. 6 | Coordination of forecasts | |

## Appendix F
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| Authority | Required Information | Location in Application |
|---|---|---|
| A. | Description of extent applicant coordinates load forecasts with other systems; and | Appendix A |
| B. | Description of forecast coordination, including problems experienced. | Appendix A |
| Minn. R. 7849.0280 | System Capacity Description | |
| A. | Brief discussion of power planning programs applied to applicant's system; | Appendix D |
| B. | Applicant's seasonal firm purchases/firm sales for each utility involved in each transaction for each forecast year; | Appendix D |
| C. | Applicant's seasonal firm participation purchases/sales for each utility involved in each transaction for each forecast year; | Appendix D |
| D. | Load and generation capacity data for sub-items below for summer and winter seasons for each forecast year, including anticipated purchases, sales, and capacity retirements/additions: | |
| (1) | Seasonal system demand; | Appendix D |
| (2) | Annual system demand; | Appendix D |
| (3) | Total seasonal firm purchases; | Appendix D |
| (4) | Total seasonal firm sales; | Appendix D |
| (5) | Seasonal adjusted net demand; | Appendix D |
| (6) | Annual adjusted net demand; | Appendix D |
| (7) | Net generating capacity; | Appendix D |

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| Authority | Required Information | Location in Application |
|---|---|---|
| (8) | Total participation purchases; | Appendix D |
| (9) | Total participation sales; | Appendix D |
| (10) | Adjusted net capability; | Appendix D |
| (11) | Net reserve capacity obligation; | Appendix D |
| (12) | Total firm capacity obligation; and | Appendix D |
| (13) | Surplus or deficit capacity; | Appendix D |
| E. | Load and generation capacity data requested in item D/sub-items (1)-(13) for summer and winter seasons for each forecast year subsequent to the year of application, including purchases, sales, and generating capability contingent on the proposed facility; | Appendix D |
| F. | Load and generation capacity data requested in item D/sub-items (1)-(13) for summer and winter seasons for each forecast year subsequent to the year of application, including all projected purchases, sales, and generating capability; | Appendix D |
| G. | List of proposed additions/retirements in net generating capability for each forecast year subsequent to the year of application; | Appendix D |
| H. | Graph showing monthly adjusted net demand, monthly adjusted net capability, and difference between adjusted net capability and actual, planned, or estimated maintenance outages of generation/ transmission for specified time periods; and | Appendix D |

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| Authority | Required Information | Location in Application |
|---|---|---|
| I. | Discussion of method and appropriateness of determining system reserve margins. | Appendix D |
| Minn. R. 7849.0290 | Conservation Programs | |
| A. | Name of committee, department, individual responsible for applicant's energy conservation/efficiency programs, including load management; | Appendix B |
| B. | List of applicant's conservation/efficiency goals and objectives; | Appendix B |
| C. | Description of specific energy conservation/efficiency programs considered, a list of those implemented, and reasons why other programs have not been implemented; | Appendix B |
| D. | Description of major energy conservation/efficiency accomplishments by applicant; | Appendix B |
| E. | Description of applicant's energy conservation/efficiency plans through the forecast years; and | Appendix B |
| F. | Quantification of how energy conservation/efficiency programs affect the 7849.0270, subp. 2 forecast, a list of total program costs, and discussion of expected program effects in reducing need for new generation and transmission. | Sections 1.6 and 5.5; Appendices A and B |
| Minn. R. 7849.0300 | Consequence of Delay | Sections 1.1.2 , 1.7; Chapter 3 |
| Minn. R. 7849.0310 | Required Environmental Information | Chapter 6 |
| Minn. R. 7849.0320 | Information for Generating Facilities and Alternatives | |

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| Authority | Required Information | Location in Application |
|---|---|---|
| A. | Estimated land requirements for facility, water storage, cooling system, and solid waste storages; | Sections 6.3, 6.4 and 6.9; Appendix C, Tables C4a and C4b |
| B. | Estimated amount of vehicular, rail, and barge traffic due to construction and operation; | Section 6.13 |
| C. | For fossil-fueled facilities: | |
| (1) | Expected regional sources of fuel; | Appendix C, Tables C2a and C2b |
| (2) | Typical hourly and annual fuel requirement ; | Appendix C, Tables C2a and C2b |
| (3) | Expected rate of heat input in Btu/hour ; | Appendix C, Tables C2a and C2b |
| (4) | Typical range of fuel's heat value and typical average of fuel's heat value; and | Appendix C, Tables C2a and C2b |
| (5) | Typical ranges of sulfur, ash, and moisture content of fuel; | Appendix C, Tables C2a and C2b |
| D. | For fossil-fueled facilities: | |
| (1) | Estimated range of emissions of sulfur dioxide, nitrogen oxides, and particulates in pounds/hour; and | Section 6.1 |
| (2) | Estimated range of maximum contributions to 24-hr ground level concentrations of sulfur dioxide, nitrogen oxides, and particulates in micrograms per cubic meter; | Section 6.1 |
| E. | Water use by the facility for alternate cooling system, including: | |

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| Authority | Required Information | Location in Application |
|---|---|---|
| (1) | Estimated maximum use, including groundwater pumping rate in gallons/minute and surface water appropriation in cubit feet/second; | Section 6.3; Appendix C, Tables C4a and C4b |
| (2) | Estimated groundwater appropriation in million gallons/year; and | Appendix C, Tables C4a and C4b |
| (3) | Annual consumption in acre-feet; | Appendix C, Tables C4a and C4b |
| F. | Potential sources/types of discharges to water; | Section 6.4 |
| G. | Radioactive releases, including: | |
| (1) | For nuclear facilities, typical types/amounts of radionuclides released in curies/year; and | Not applicable |
| (2) | For fossil-fueled facilities, estimated range of radioactivity released in curies per year; | Section 6.4 |
| H. | Potential types/quantities of solid wastes produced in tons/year; | Section 6.4 |
| I. | Potential sources/types of audible noise; | Section 6.2 |
| J. | Estimated work force required for construction and operation; and | Appendix C, Tables C3a and C3b |
| K. | Minimum number/size of transmission facilities required for reliable outlet. | Sections 4.2 and 4.3 |
| Minn. R. 7849.0340 | No-Facility Alternative | Chapter 3 |
| Minn. Stat. §§ 216B.2422, subd. 4; 216B.243, subd. 3a | Whether the applicant for a project generating nonrenewable energy has demonstrated that the project is less expensive than one generating renewable energy or is otherwise in the public interest. | Section 5.4 |

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| Authority | Required Information | Location in Application |
|---|---|---|
| Minn. Stat. §§ 216B.1612, subd. 5(c); 216B.243, subd. 3(10) | Whether the applicant is in compliance with Minnesota's renewable energy objectives, including purchasing energy from C-BED projects. | Section 5.4 |
| Minn. Stat. § 216B.2426 | Whether the applicant has considered the opportunities for installation of distributed generation. | Section 5.6 |
| Minn. Stat. § 216H.03, subd. 3(2) | Whether the proposed new large energy facility would contribute to statewide power sector carbon dioxide emissions. | Xcel Energy is proposing simple cycle natural gas peaking generation that does not come within the statute's definition of a large energy facility. |
| Minn. Stat. § 216B.243, subd. 3(12) | Whether an applicant proposing a nonrenewable energy generating plant has assessed the risk of environmental costs and regulation over the expected useful life of the plant. | Section 5.4 |
| Minn. Stat. § 216B.1694, subd. (2)(5) | Whether the applicant has considered an innovative energy project as a supply option before expanding a fossil-fuel-fired generation facility or entering into a 5+-year purchased power agreement. | Section 5.6 |