Public Document
Trade Secret Data Excised

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR THREE NATURAL GAS COMBUSTION TURBINE GENERATORS

Case No. PU-13-_____

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR TWO NATURAL GAS COMBUSTION TURBINE GENERATORS

Case No. PU-13-_____

APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE AND CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, respectfully submits to the North Dakota Public Service Commission this Application for an Advance Determination of Prudence (ADP) pursuant to North Dakota Century Code § 49-05-16, for its proposal to add three 215 MW natural-gas-fired, simple cycle, combustion turbine (CT) generators to its system. The first CT would be constructed at Xcel Energy's Back Dog generation plant in Burnsville, Minnesota (Black Dog Unit 6) for service beginning in 2017. The second and third CTs would be constructed at a new plant site to be located in the Red River Valley near Hankinson, North Dakota (Red River Valley Units 1 and 2) for service beginning in 2018 and 2019.

We are also requesting through this Application that the Commission grant a Certificate of Public Convenience and Necessity for Red River Valley Units 1 and 2, pursuant to North Dakota Century Code Chapter 49-03.

The Company's proposal is the result of its most recent resource planning cycle, which included filings with the North Dakota Public Service Commission (Case No.

45 PU-13-195 Filed 11/26/2013 Pages: 42
Exhibit NSP-1
Northern States Power Company

39 PU-13-194 Filed 11/26/2013 Pages: 42
Exhibit NSP-1
Northern States Power Company

PU-10-580) and Minnesota Public Utilities Commission (MPUC Docket No. E002/RP-10-825). Our analysis, which included significant stakeholder input, identified a capacity deficit of approximately 150 MW that grows to approximately 500 MW in 2019.

On November 21, 2012, the MPUC issued an order establishing a competitive resource acquisition process to determine the resource(s) to meet Xcel Energy's identified need of 150-500 MW in the 2017-2019 time period. The Company has also filed this proposal to add three CT generators to its system in the MPUC's competitive acquisition process proceeding.

II. OVERVIEW OF FILING

Xcel Energy is proposing the following locations and schedule for the addition of three CT generators to the Xcel Energy system:

- **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.

- **Red River Valley Unit 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 to locate generation near our North Dakota load.

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

The Company's proposal prudently addresses the identified capacity need on our system for the following reasons:

- *Timing and Cost of System Additions are Prudent.* Our approach delivers cost-effective capacity to satisfy current identified need, ensuring that Xcel Energy will have sufficient generating resources under reasonably foreseeable circumstances in the 2017-2109 timeframe at the least cost to ratepayers.

  These proposed additions to our generation fleet closely match the resource need identified by the Company. Our incremental approach and implementation schedule does not rely on building a larger power plant in 2017, which 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. 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 customers' electricity demands without overreliance on the MISO electricity market.

  Our Proposal to deploy three CTs in geographically diverse areas is also the most cost-effective addition we have identified for our customers. 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.

- *Enhances the Reliability of Local System Operations.* 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.

  Xcel Energy serves approximately 90,000 customers in North Dakota, with the majority of those located in the greater Red River Valley, including the communities of Fargo and Grand Forks. The Hankinson site appropriately balances low cost and strategic location. This site is approximately 70 miles from our Fargo load center, near the juncture of the Otter Tail Power 230 kV transmission system and Alliance 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 existing fleet.

- *Provides Important Flexibility in Implementing System Additions.* 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 capacity in smaller increments and strategically place it in our system. In addition, our proposal is modular; each CT unit can be deployed independent of the others. This allows for adjustments to unit schedules – or even the cancellation of units – before major expenditures are made in the event new information in 2014 or 2015 warrants reassessment of the capacity need on our system.

  In support of our request for an ADP for Black Dog Unit 6 and Red River Valley Units 1 and 2, the Company has filed the Direct Testimony and Schedules of the following witnesses:

  - *Laura McCarten*, who explains the public policy benefits and potential risks associated with the CT generators, and the framework for regulatory review of the Company's proposal.
  - *Steven W. Wishart*, who describes the Company's identified capacity need for the 2017-2019 time period; and
  - *Gregory L. Ford*, who describes the CT generators' design, operations and maintenance, and construction costs and schedule.

The remainder of the Application is organized into the following sections:

III. Description of Applicant and Resource Review Process;
IV. Communications and Service;
V. Standard for Review;
VI. Description of Need;
VII. Description of the Company's Proposal;
VIII. Alternatives Considered;
IX. Reasons Supporting an ADP;
X. Reasons Supporting a CPCN; and
XI. Conclusion

III. DESCRIPTION OF APPLICANT AND RESOURCE REVIEW PROCESS

A. Xcel Energy

Northern States Power Company, doing business as Xcel Energy, is duly authorized to conduct business in the State of North Dakota as a foreign corporation. The Company conducts business in the State of North Dakota as a public utility subject to the jurisdiction and regulation of the Commission pursuant to Title 49 of the North Dakota Century Code. The name and address of Xcel Energy is:

Northern States Power Company
414 Nicollet Mall
Minneapolis, Minnesota 55401

Xcel Energy also operates in North Dakota from the following address:

Northern States Power Company
2302 Great Northern Drive
Fargo, North Dakota 58102

The Company's Certificate of Incorporation with amendments and Certificate of Authority were filed with the Commission on September 30, 2009 and October 12, 2009, respectively, in Case No. PU-09-664. Current Certificates of Good Standing issued by the North Dakota and Minnesota Secretaries of State were filed in the same docket on March 11, 2013, and are incorporated herein by reference.

Xcel Energy has service territory in five upper Midwest states including North Dakota. We presently serve approximately 90,000 retail electric customers in and around Fargo, Grand Forks, and Minot, North Dakota. We own just over 250 miles of transmission lines and 14 substation in North Dakota.

B. Resource Review Process

Xcel Energy's service territory includes areas of North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. Thus, the operation of Xcel Energy's system is subject to the regulatory oversight of five state public utility commissions, as well as input from various stakeholders within each state.

The Company's resource planning is conducted for the integrated Xcel Energy system that provides service to all customers across its five-state Upper Midwest service territory. In North Dakota, the Company has committed to keep the Commission informed of its resource needs by filing our resource plans with the Commission, and filing an ADP application when we intend to add a resource to our system.[1] In addition, the Company must obtain a CPCN for a proposed resource to be located in North Dakota. In Minnesota, resource additions are subject to resource planning proceedings before the MPUC, followed by a competitive resource acquisition proceeding if the Company proposes to build the resource itself.[2]

The Company's proposal to add three CT generators to its system has been filed in the competitive resource acquisition docket opened by the MPUC to select the resource(s) that will meet Xcel Energy's identified need of 150-500 MW in the 2017-2019 time period (MPUC Docket No. E002/CN-12-1240). The MPUC requires a competitive resource acquisition proceeding whenever the Company proposes to self-build a resource.[3] This is to ensure that independent power providers have an opportunity to sponsor proposals to compete with the Company's self-build proposal.

The competitive resource acquisition process consists of the following steps:

- The MPUC 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 resource 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 MPUC determines that the proposal filings are adequate, a contested case is conducted before an administrative law judge. At the end of the hearing

---

[1] *See* November 5, 2012 letter from Judy Poferl to the Commission in Case No. PU-12-059, committing the Company to file an ADP application with the Commission whenever it pursues a significant system resource acquisition.

[2] Resource review in South Dakota is handled through a prudence review when the utility files a rate case that proposes adding the resource to rate base. In Wisconsin and Michigan, the addition of new resources is subject to FERC-filed interchange agreements that the Xcel Energy operating companies in those states have with Xcel Energy.

[3] *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).

process the administrative law judge provides findings and recommendations to the MPUC.

- The MPUC considers the developed record, issues its resource selection, and grants any associated certificates of need.
- In the event the MPUC selects a power provider proposal rather than the Company's self-build proposal, the Company and selected power provider have four months to negotiate a power purchase agreement and bring it back to the Commission for approval.

The MPUC ordered that participants in the competitive resource acquisition docket may propose a variety of resources to meet the identified need, including:

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

This means that two or more proposals could be combined if the MPUC determines that the combination is the most reliable and cost-effective way to adequately meet the Company's identified need.

Great River Energy, Calpine Corp., Invenergy, and Geronimo Wind have filed proposals in the MPUC's competitive resource acquisition docket to compete with the Company's three CT generator proposal.[4]

The Company's proposal to add three CT generators to its system in Minnesota and North Dakota requires approvals from regulatory authorities in both states. The Company intends to keep the Commission and MPUC informed of developments in the resource acquisition review proceedings to facilitate obtaining the necessary approvals for the Company's proposal.[5]

---

[4] To date, the Company has not been able to review the substance of these purchased power agreement proposals because they contain trade secret data to which the Company does not have access. The Company is currently working with the parties to resolve this issue through a nondisclosure agreement.

[5] Once the trade secret data issue is resolved, the Company will update the Commission on the essential elements of the proposed PPAs consistent with the applicable restrictions on the disclosure of trade secret data.

IV. COMMUNICATIONS AND SERVICE

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

James R. Alders
Strategy Consultant, Regulatory Affairs
Xcel Energy
414 Nicollet Mall, 7th Floor
Minneapolis, MN 55401

SaGonna Thompson
Records Specialist
Xcel Energy
414 Nicollet Mall, 7th Floor
Minneapolis, MN 55401

David H. Sederquist
Senior Consultant, Regulation and Finance
Xcel Energy
2302 Great Northern Drive
Fargo, ND 58102

V. STANDARD FOR REVIEW

A. Standard for Advance Determination of Prudence

North Dakota Century Code Section 49-05-16 (1)(d) authorizes the Commission to issue an ADP if it "determines that the resource addition is prudent." Section 49-05-16 (7) further provides that "[t]here is a rebuttable presumption that a resource addition located in the state is prudent."

This standard is similar to the "honestly and prudently invested" standard that the Commission uses for ratemaking. *See* N.D.C.C. § 49-06-02. The general prudence standard calls for determining whether the utility action was reasonable at the time it was taken under all relevant circumstances. *See* Charles F. Philips, Jr., *The Regulation of Public Utilities – Theory and Practice* at 292 (Public Utility Reports 1988); *see also* David. J. Muchow, William A. Mogel, *Energy Law and Transactions* at § 4.02[3][b] (2009). Under N.D.C.C. § 49-05-16 (1), the Commission may issue an order approving the prudence of a proposed project if four conditions are met:

a. The public utility files with its application a projection of costs to the date of the anticipated commercial operation of the resource addition;
b. The public utility files with its application a fee in the amount of one hundred twenty-five thousand dollars;

c. The commission provides notice and holds a hearing, if appropriate, in accordance with section 49-02-02; and
d. The commission determines that the resource addition is prudent. For facilities located or to be located in this state the commission, in determining whether the resource addition is prudent, shall consider the benefits of having the resource addition located in this state.

B. Standard for Certificate of Public Convenience and Necessity

North Dakota Century Code Section 49-03-01 provides that:

> An electric public utility may not begin construction or operation of a public utility plant or system, or of an extension of a plant or system without first obtaining from the commission a certificate that public convenience and necessity require or will require such construction and operation.

Before the Commission may issue a CPCN, the electric public utility must file a certified copy of its articles of incorporation, and submit evidence that it has obtained, or will make application to obtain, the consent of any other public authority whose consent is required. N.D.C.C. § 49-03-02. After notice and hearing, the Commission may: (i) issue the certificate; (ii) refuse to issue the certificate; (iii) issue the certificate for only portions of the proposed facilities; or (iv) issue the certificate subject to such terms and conditions the Commission determines the public convenience and necessity requires.

The Commission has indicated that it considers an additional ten factors in determining whether to grant a CPCN for new electric facilities, relating to whether the facilities extend into and impact other electric service providers' service territories, and whether the facilities are unnecessarily duplicative.[6]

The overall standard applied by the Commission pursuant to statute and its ten factors is whether the proposed system addition is needed under all the circumstances, and whether the applicant is qualified to implement the proposed system addition.

---

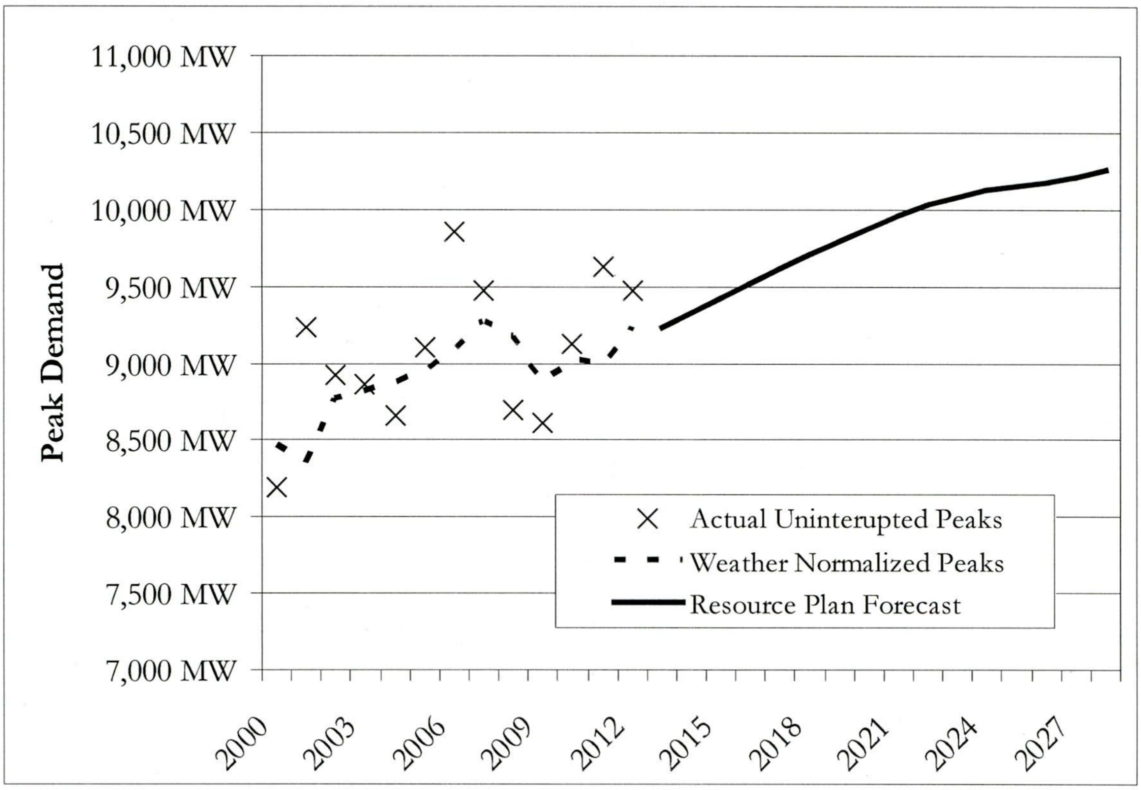
[6] Testimony of Jerry Lein of the Commission Staff, presented to the Interim Electric Industry Competition Committee, April 24, 2000. These factors are discussed in Section X of this Application.

VI. DESCRIPTION OF NEED

A. Identified Resource Need

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 capacity need of 150-500 MW for the 2017-2019 time period was the Company's Fall 2011 forecast, which updated our initial 2010 resource planning forecast. The Fall 2011 update reflects a large downward shift in expected customer demand as a result of the ongoing effects of the economic recession, and includes minor modeling adjustments the Minnesota Department of Commerce proposed after reviewing the updated forecast.[7] The forecast also includes the impact of the Company's on-going demand side management (DSM) efforts. Figure 1 shows the Fall 2011 peak demand forecast. From 2013 through 2020, the average rate of growth in our peak demand forecast is 1.0 percent.

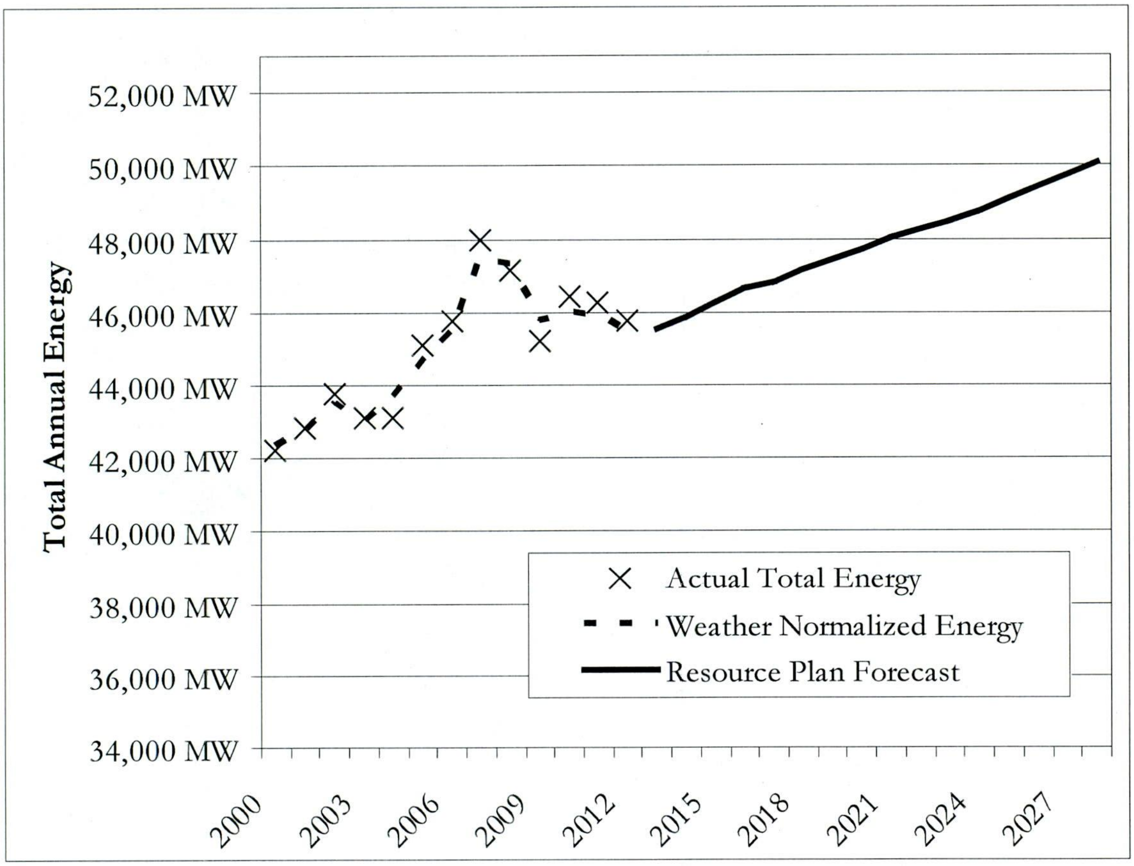
Figure 1
NSP Historic and Forecasted Peak Demand



[7] More detail on the Fall 2011 Forecast update is available in the Company's 2011-2025 Resource Plan Reply Comments at pages 6-9, filed in Case No. PU-10-580 on August 14, 2012.

In addition to updating our peak demand forecast , we also updated our forecast of total annual energy requirements (sales plus transmission losses), including the impacts of DSM. 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 to address that need. Our total annual energy forecast, shown in Figure 2, also reflects the effect of the economic recession. The average growth rate from 2013 to 2020 is 0.7 percent.

Figure 2
NSP Historic and Forecasts Total Annual Energy



Our determination of need also took into consideration 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. 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. We used a reserve margin of 3.79 percent, based on a LOLE study conducted by MISO in the Spring of 2011.

Table 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 Xcel Energy 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 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 Xcel Energy-owned resources plus purchased power, our system's forecasted capacity need is approximately 500 MW by 2019, as shown in Table 2.

Table 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

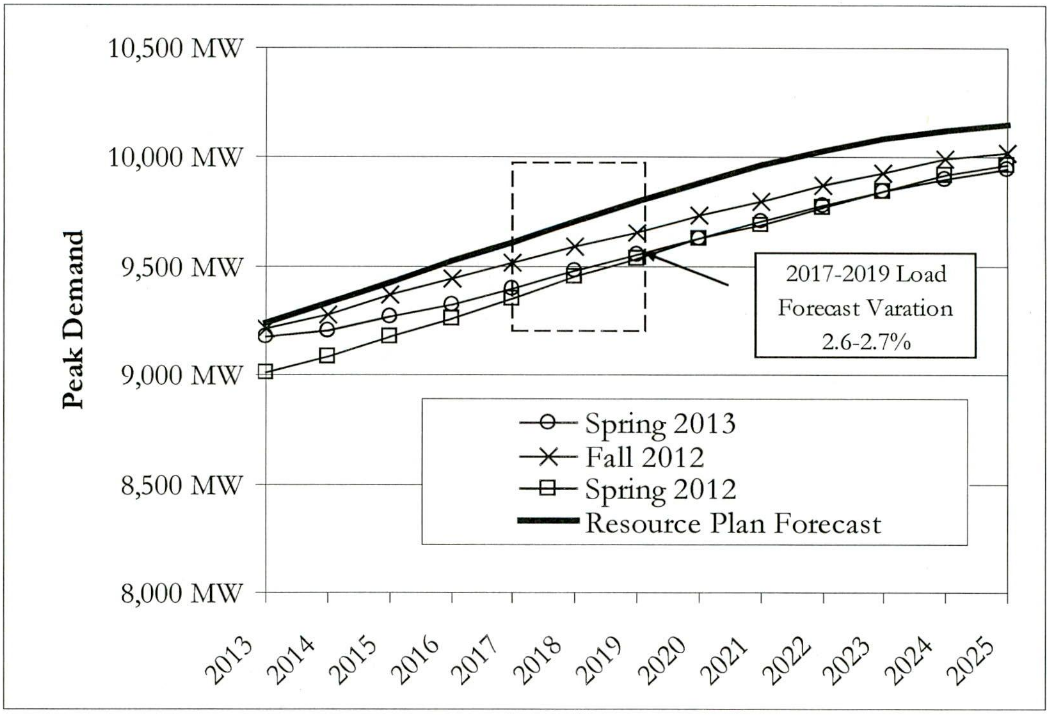
B. Forecast Uncertainty

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 our resource planning analysis was completed, we continue to believe it is appropriate to use the capacity need targets we have identified, and our proposal is designed to meet that resource need. This conservative approach is prudent, ensuring 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 provides the flexibility to defer or cancel one or more of the components of our proposal based on future circumstances.

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 its resource planning process demonstrates 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 occurs within a relatively tight range, and the amount of the variation is relatively small in the context of our total system peak demand. Since the Fall of 2011, when our 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 shows the peak demand forecast changes.

Figure 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 prudence determination based on future circumstances that may have a greater impact on customer demand.

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 analysis, 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 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
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 to 510 MW.

Tables 4, 5, and 6 compare the resource need identified in our resource planning process 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 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 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 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)**

3. *Company's Approach to Addressing Need is Prudent*

The Company believes the prudent approach is to plan to meet the current identified need on our system. This ensures adequate generating capacity under all reasonable circumstances. At the same time, our proposal provides flexibility to adjust the timing of the CT generator additions. Currently, the Company is proposing to construct the three CT generating units sequentially, in 2017, 2018, and 2019. The construction schedules associated with these in-service dates provide the flexibility to alter a unit's in-service date or cancel one or more of our proposed units to match the growth in customer demand and minimize rate impacts for our customer.

VII. DESCRIPTION OF THE COMPANY'S PROPOSAL

This section provides information on the design, costs, operation and maintenance, and timing for construction of the Company's proposal to add three CT generators to the Xcel Energy system.

A. Combustion Turbine Generation Design and Construction

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. A schematic of two combustion turbine units as they would be configured at the Red River Valley plant site is shown in Figure 5 below.

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

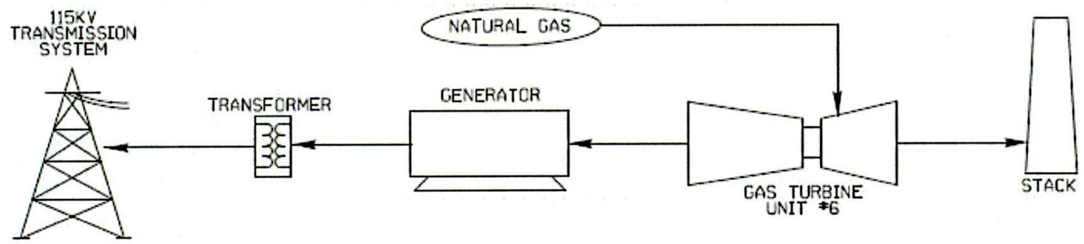
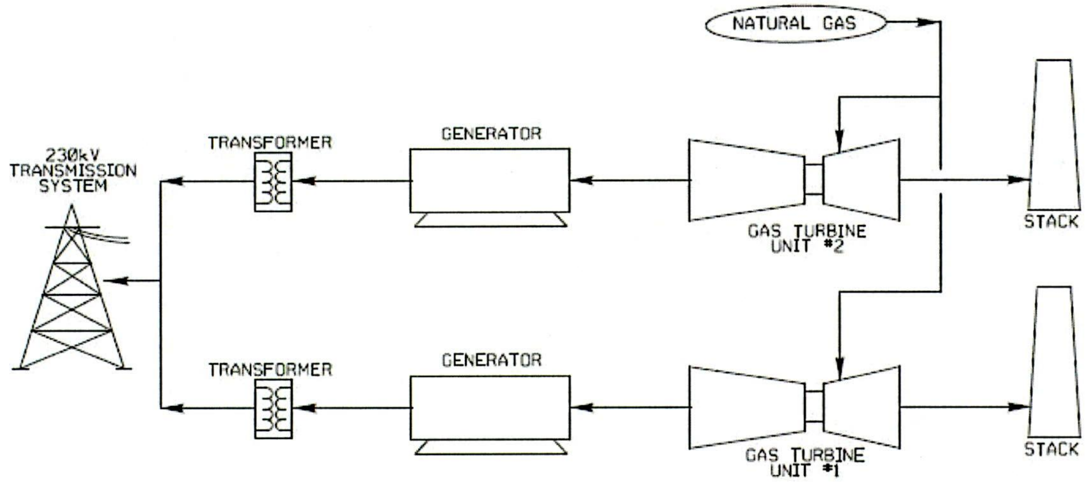


Figure 5
Schematic Diagram of a 2 Unit Simple Cycle Facility



The design capacity of the units 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 150 MW in 10 minutes from a cold start, operate in a range of at least 50 to 100 percent 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 115 kV or 230 kV; and
7. Auxiliary Transformer, which converts some of the output power to lower voltages for use by the Unit's auxiliary equipment.

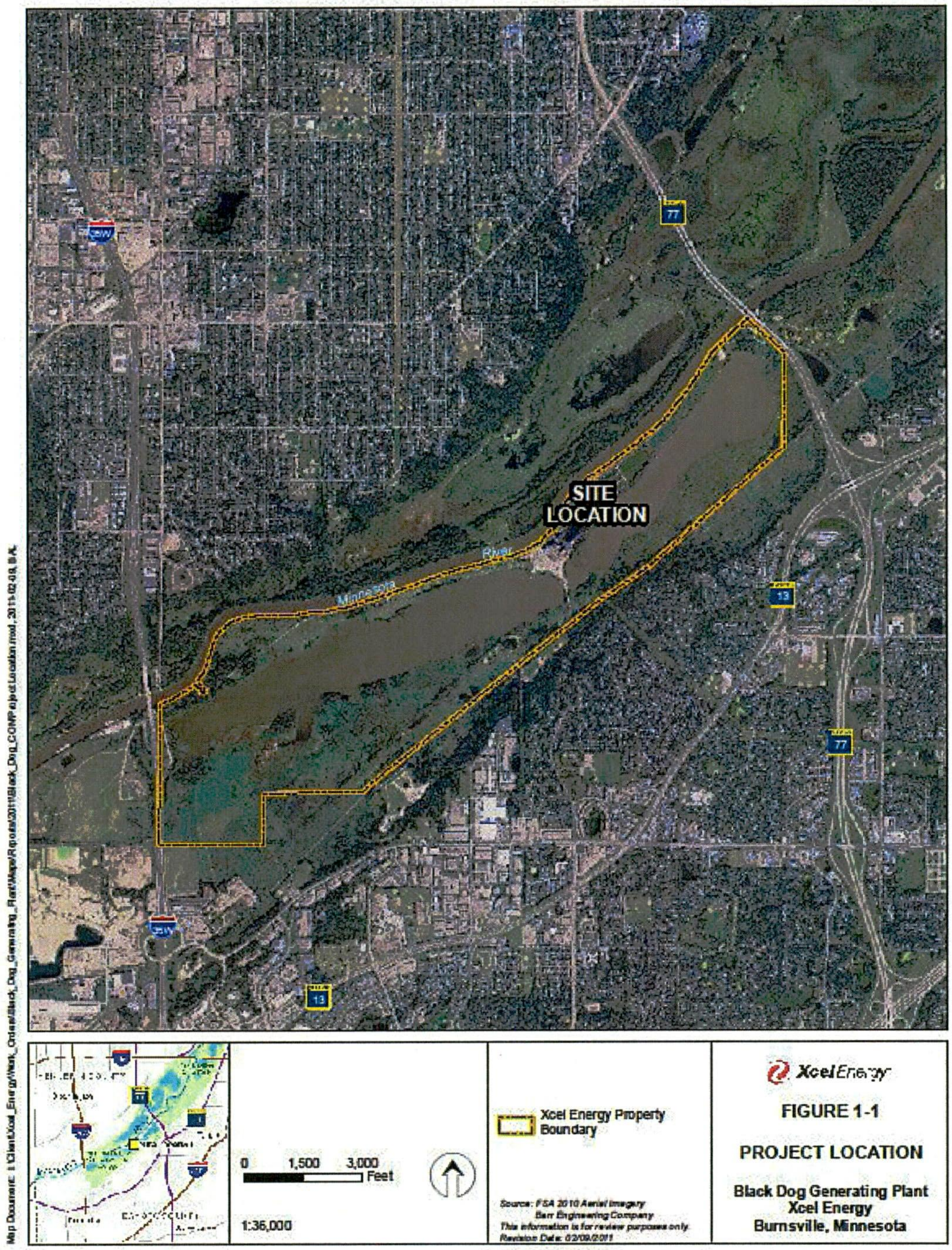
The combustion turbine units will be integrated into our remote dispatch control center. We expect to use the units for peaking load service, dispatching them after all lower cost and "must run" units. They are expected to be dispatched primarily during higher system load periods in the summer and winter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

1. 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 6). The Black Dog plant is currently a coal- and gas-fired generating station.

Figure 6
Black Dog Plant Site

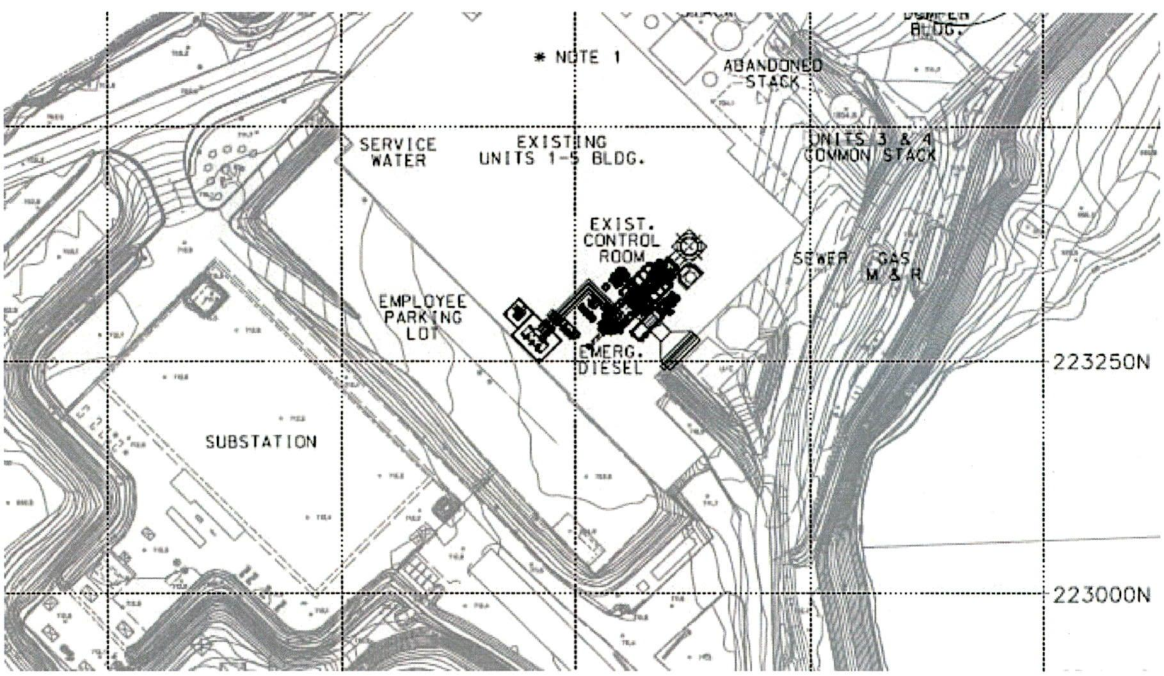


The original Unit 1 boiler/turbine and the Unit 2 boiler, installed at the site in the 1950s and fired on coal, were repowered with a natural gas combined-cycle unit (Unit 5), which includes a natural gas combustion turbine-generator combined with a heat recovery steam generator that delivers steam to 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 7.

Figure 7
Project Layout



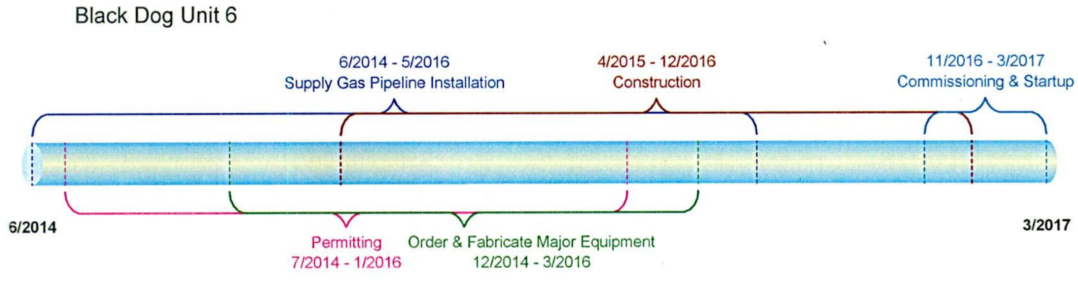
The exhaust stack will be approximately 200 feet tall and located adjacent to Unit 6, in the area of the existing Unit 4 boiler. The new unit will be connected to the existing 115 kV substation. Minor modifications to the existing 115 kV switchyard will be required to connect it to the transmission system. 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 95° F 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 8 below. Start-up of the unit would occur in early 2017. Unit 6 is expected to be in commercial operation late in the first quarter of 2017.

Figure 8
Black Dog Unit 6 Construction Schedule



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. The capital cost of Black Dog Unit 6 is presented in Section V.D below.

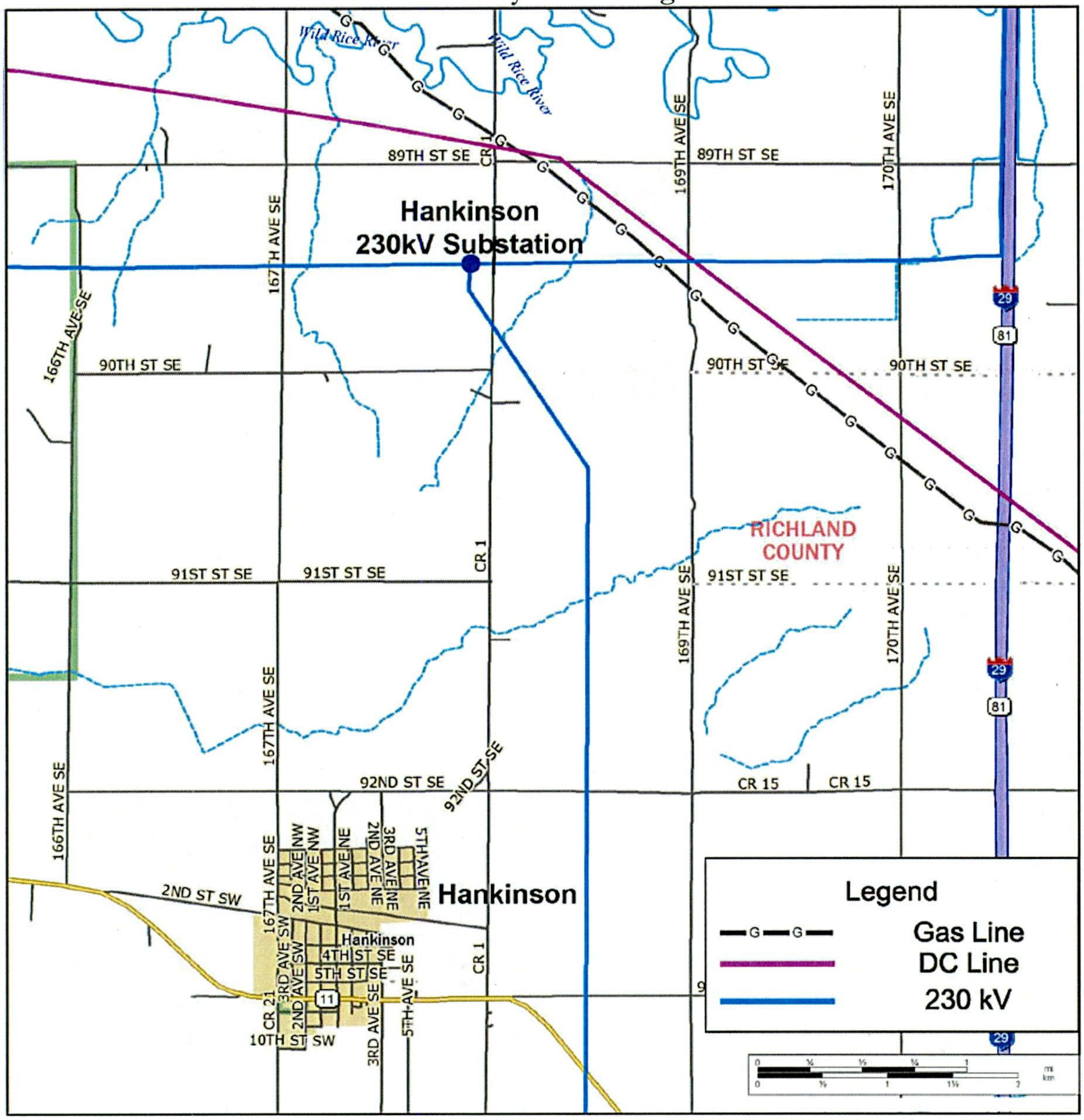
Figure 9 provides a preliminary artist's rendering of what the Black Dog plant site will look like after installation of Black Dog Unit 6.

Figure 9
Black Dog Plant Rendering

2. Red River Valley Units 1 and 2

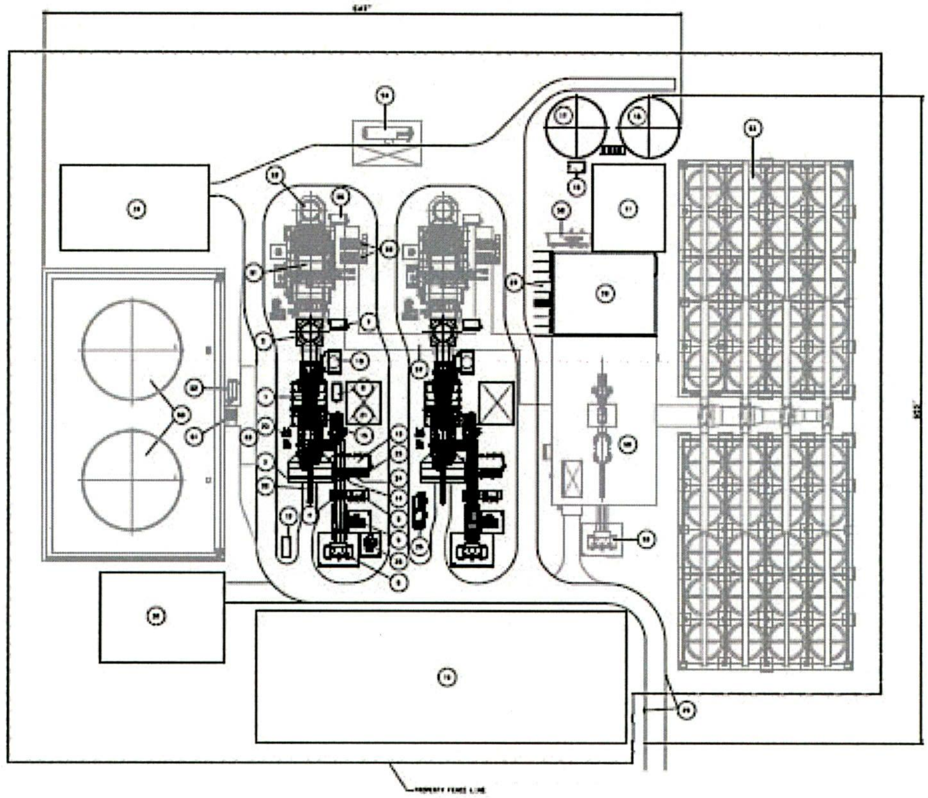
A specific plant site for the two Red River Valley units in southeast North Dakota has not been selected at this time. We reviewed the option of locating the plant in the vicinity of Fargo, but determined this would involve increased costs to connect the plant site to a natural gas pipeline for its fuel, as well as to connect it to outlet transmission. As a result, we currently anticipate that the facility will be located further south, in the general vicinity of Hankinson, North Dakota. That 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 10 shows the area under consideration in the southeast corner of North Dakota.

Figure 10
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 would allow for two combustion turbines to be installed, and for conversion of the two units to a combined cycle configuration in the future. A preliminary layout for two combustion turbines is shown in Figure 11.

Figure 11
Potential Layout of Red River Valley Facility



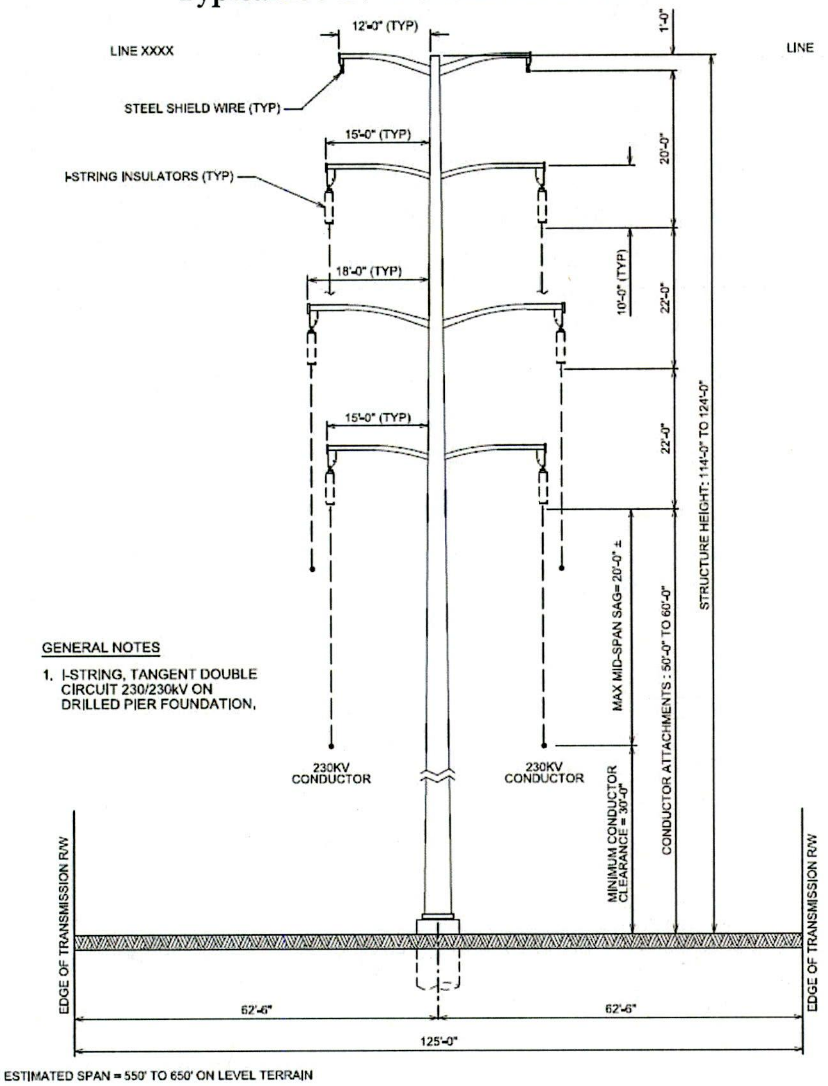
It is anticipated that the tallest structure within the plant will be the stacks, at approximately 65 feet. The combustion turbines and building are all expected to be less than 40 feet in height.

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 88° F 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 230 kV 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 12 below is an illustration of a typical 230 kV structure.

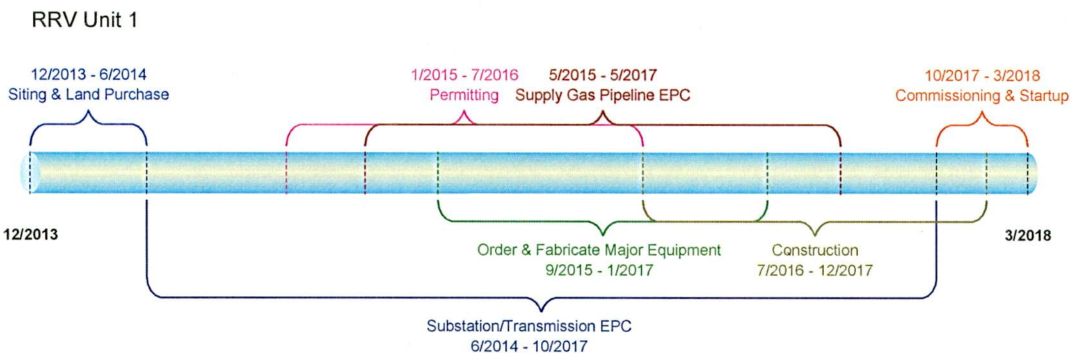
Figure 12
Typical 230 kV Transmission Pole

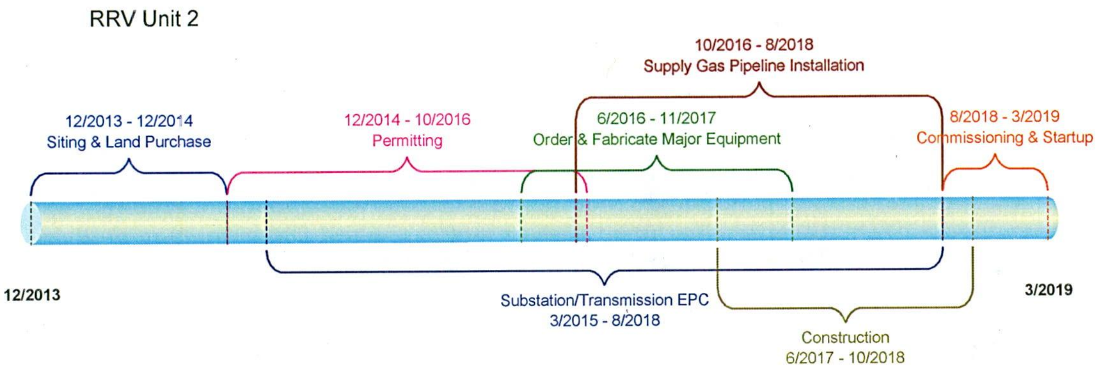


The Company has identified the likely transmission upgrades needed to interconnect the peaking generation at the Red River Valley site through a preliminary generation interconnection study. The study indicated that two system upgrades may be required to support interconnection: 1) the completion of 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 13 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 13
Potential Construction Schedule Red River Valley Units 1 and 2





The new Red River Valley plant will be operated and maintained by a full time staff of three to five employees 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. The capital cost of Red River Valley Units 1 and 2 is presented in Section V.D below. We have included 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.

Figure 14 below is an artist's rendering of what the Red River Valley plant will look like if both units are selected for construction.

Figure 14
Red River Valley Site - Artist's Rendering

B. Combustion Turbine 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.

C. Implementation of the Company's Proposal

The deployment of the three CTs is based on their cost-effectiveness relative to one another and the system as a whole.

Black Dog Unit 6 is the least-cost unit because it can take advantage of existing infrastructure at an existing plant site. First, the new CT will be located in an existing powerhouse that will be available upon the retirement and removal of the units currently in the powerhouse. Unit 6 will also be connected to the existing 115 kV substation at the site. While minor modifications to the switchyard will be required to connect the new unit 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 the retired units.

Because Black Dog Unit 6 is the most cost effective of the three combustion turbines the Company is proposing, we have recommend that it be developed first, followed by the Red River Valley units. Black Dog Unit 6 is therefore slated to address the 150 MW shortfall identified for 2017, and the Red River Valley Units are slated to address the remaining 350 MW shortfall identified for the 2018-19 period.

D. Cost of the Company's Proposal

Table 7 below provides the estimated costs for Black Dog Unit 6 and Red River Valley Units 1 and 2. It also provides an estimate of the costs that would be incurred even if a selected CT generator was ultimately cancelled.

Table 7
CT Generator Capital Costs
($ millions)

	Black Dog Unit 6			**Red River Valley Units 1 and 2**	
Unit	6	6 (option 1)	6 (option 2)	1	2
In-Service Date	March 2017	March 2018	March 2019	March 2018	February 2019
	[TRADE SECRET DATA BEGINS . . .				
Generator					
Transmission					
Gas					
Total					
Costs Incurred					
					. . . TRADE SECRET DATA ENDS]

The cost for Black Dog Unit 6 with an in-service date of 2017 is approximately **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** (including transmission). The cost for Red River Unit 1 is approximately **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** in 2018, and approximately **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** for Red River Unit 2 in 2019. The first Red River unit's cost is about 38 percent greater than for Black Dog Unit 6, while the second Red River unit's cost is about 24 percent greater.

We have also provided costs for later in service dates for Black Dog Unit 6. The flexibility in the deployment of the Black Dog unit is not only in response to the uncertainty that surrounds the level of need that may develop over the 2017-2019 time period; it also provides the flexibility necessary for the MPUC's competitive resource acquisition process. Competitive proposals in that docket may address only portions of the Company's need, and may be combined with other proposals to meet the Company's entire need. Under these circumstances, the Company's proposal to add a CT generator at Black Dog could be combined with another proposal, with the other proposal covering the Company's need for the 2017 or 2017-2018 time period and Black Dog Unit 6 covering the need for 2019 and beyond. As a result, the Company has developed estimated capital costs that reflect the possibility of Black Dog Unit 6 going into service in 2017, 2018, or 2019.

The Company also estimated the cost for both Red River Valley units going into service in 2018. The cost is approximately **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]**, which is **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** less than the **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** cost to build the units sequentially in 2018 and 2019.

E. Flexibility in Implementing Company's Proposal

Our proposal to add three CT generators to the Xcel Energy system provides considerable flexibility with respect to the number and timing of the combustion turbine units we offer.

Flexibility as to Number of CT Generators

We provide flexibility on the number of units to be ultimately constructed. Each of the three units has been designed to be a separate project that can be implemented independently. One, two, or three CT units could be constructed for service in the 2017-2019 timeframe.

Flexibility as to Timing of CT Generator Deployment

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. Depending on the level of need that develops, as well as the other competing proposals submitted in the MPUC's competitive resource acquisition docket, Black Dog Unit 6 could go into service in 2017, 2018, and 2019, while Red River Units 1 and 2 could both go into service together in 2018, or sequentially in 2018 and 2019.

In the event that the Company's proposal is selected, the Company anticipates that the Commission may wish for 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. Based on the information provided, there would be time to cancel a CT in the 2018 and 2109 timeframe before significant expense was incurred.

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 Table 7 above the relatively small expenditures anticipated in 2014 and 2015 for a unit put into service in 2018 or 2019 unit. If a unit was cancelled at the end of 2014 or 2015, we would seek to recover those prudently incurred development expenditures represented in our estimates. The recovery of these minimal costs is analogous to cancelation fees that might be included in a development contract with an independent power supplier.

VIII. ALTERNATIVES CONSIDERED

This section discusses alternatives that were considered in the course of developing our proposal. One of the main tools we used to develop the Company's proposal and compare it with other types of resources was the Strategist resource planning model. We have used Strategist in many previous dockets across the Company's service territory in the Upper Midwest (North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan).

In setting up Strategist to assess resource options, the Company used the following assumptions for its base case. The load forecast that was used is shown in Figure 1 and discussed in Section VI of this Application. The costs used for our proposed natural gas combustion turbines are shown in Table 7, and the CTs' performance characteristics used are described in Section VII, of this Application. The model was updated with our latest forecast of natural gas prices and MISO market prices for on- and off-peak energy. The rest of the model inputs defined the costs and operating characteristics of the rest of the NSP System generation portfolio. These inputs have been developed and refined over the past two years and are based on generation testing data and other internally developed information. No costs were applied to emissions of any type in the Strategist model.

A. Peaking and Intermediate Natural Gas Resources

The Company examined the cost effectiveness of peaking and intermediate natural gas generation in developing our 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.

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 were 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. The Strategist inputs reflected the expectation that the units will have high availability factors and low emission rates. The model also specified that our proposed combustion turbines qualified as quick start resources, meaning that Strategist could count a portion of their capacity to the system operating reserve margin before the units were dispatched to serve load.

The costs associated with the Company's proposed peaking units are primarily capital expenditures. Black Dog Unit 6 was 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 the Black Dog unit 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 facility estimate on the cost of a generic 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 8 shows that our peaking alternative had a lower net system cost of $217 million compared to the generic intermediate unit using base case assumptions.

Table 8
System Cost Comparison of Peaking and Intermediate Alternatives

	Total PVRR 2013- 2050 ($ Millions)	Incremental Over Peaking Units
Peaking Units: **3 CTs @ 209 MW**	$81,302	-
Intermediate Unit: **1 CC @ 684 MW**	$81,519	+ $217

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.

B. Analysis of Other Alternatives

1. Purchased Power

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 customers for even longer if the life of the unit is extended, as is often the case.

Short-term purchase power agreements (less than five 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.

Five PPA proposals have been filed in the competitive resource acquisition docket that Xcel Energy is participating in before the MPUC. The Company will provide the

Commission information as it becomes available on the cost-effectiveness of these proposed PPAs in meeting the Company's identified capacity needs.

2. *Demand Side Management*

Demand-Side Management (DSM) is a potential alternative to new generation. The Company's current goal for the 2013-2015 time period is to achieve 1.5 percent savings. This is an aggressive goal, and additional gains may be difficult to achieve and sustain.

We undertook a benchmarking study that projected the potential 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 planning cycle. However, at this time, we do not believe that conservation measures can be relied on to reduce the current identified need.

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. At this time the Company has not identified any combination of cost effective efficiency opportunities within our generation fleet that could add that level of capacity to our system.

3. *Renewables*

The Company looked at biomass and hydro as dispatchable resources that could potentially meet the identified capacity need. However, the Company could not develop hydro resources itself to meet the need, and Strategist modeling of a biomass alternative demonstrated it was prohibitively expensive. The Company also considered wind and solar, which although not dispatchable can receive capacity accreditation from MISO at a sufficient MW level. Strategist modeling demonstrated that they, too, were prohibitively expensive.

IX. REASONS SUPPORTING ADP

A. The Company's Proposal is Prudent Way to Meet the Identified Need

Our proposal has a number of benefits that make it a prudent choice for our customers.

1. Ensures Reliable, Cost-Effective Power Supply for Our Customers

Our proposal closely matches the resource need identified in the Company's resource planning process. 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. The combined capacity of the three CT generators 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.

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.

2. Enhances 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 90,000 customers in North Dakota and most of them are located within 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 existing generation fleet. 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.

3. Provides Important Flexibility in Meeting Need

Our proposal provides important flexibility to adjust generation deployment to better manage the inherent uncertainty in customer demand forecasts and minimize the impact of capital commitments on customer rates. The combustion turbines we propose have relatively short development schedules, allowing us to add generating capacity in smaller increments and strategically place it in our system. As new information becomes available in 2014 and 2015, the Company will be able to determine whether it is more appropriate to delay or cancel 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 to reassess the need and adjust deployment of the 2018 and 2019 units if that is consistent with evolving circumstances. This provides the flexibility to cancel one or two of the CTs at a relatively nominal cost if future circumstances warrant doing so.

X. REASONS SUPPORTING CPCN FOR RED RIVER VALLEY UNITS

As discussed in Section VI, the Company has taken a prudent approach in addressing the need identified in our resource planning process. Our approach delivers capacity sufficient to satisfy current identified need, ensuring that Xcel Energy will have sufficient generating resources under reasonably foreseeable circumstances in the 2017 to 2109 timeframe. This approach recognizes 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 the five state region we serve continues to work through the effects of the recent recession, there is uncertainty about whether and how our overall customer demand may grow. Recent demand forecasts for our system 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 process.

Second, assessments of the amount of generation that needs to be in place to ensure reliability in the MISO market are changing. While reserve requirements have gone down in 2013 due to the use of a new methodology at MISO, 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. Given these uncertainties and our obligation to serve our customers, we concluded 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.

In the face of this uncertainty, the implementation of our proposed resource acquisition schedule is flexible and can be adjusted. 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 CTs after initial approval of the resource acquisition but before major expenditures are made. This modular approach is beneficial as it allows the Company to adjust deployment in response to changes in the level of need that develops over the 2017-20 time period. This approach means the Company would proceed with construction of the Red River Valley Units based on the latest information confirming the continued need to add them to the Xcel Energy system.

Commission's Ten Factors Support Need

Xcel Energy provides the following responses to the ten factors the Commission considers regarding a proposed facility's impacts on other service providers, and whether the facility is unnecessarily duplicative. These factors further support the need for the Red River Valley Units and Xcel Energy's qualifications to add them to its system.

1. *From whom does the customer prefer electric service?*

Customer preference in not a consideration in this circumstance. The Red River Valley Units will meet the capacity needs of the Xcel Energy system, which serves all the Company's customers within the system's five-state service area (North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan).

2. *What electric suppliers are operating in the general area?*

Electric suppliers and nearby service territories are not at issue in this circumstance. The Red River Valley Units will not provide direct retail service in competition with electric suppliers in the area.

3. *What electric supply lines exist within a two-mile radius of the locations to be served and when were they constructed?*

An electric supply line in the vicinity is not a consideration in this circumstance. The Red River Valley Units will not provide direct retail service in competition with electric suppliers in the area.

4. *What customers are served by electric suppliers within at least a two-mile radius of the location to be served?*

The customer base in the vicinity is not a consideration in this circumstance. The Red River Valley Units will meet the capacity needs of the Xcel Energy system, which serves all the Company's customers within the system's five-state service area.

5. *What are the differences, if any, between the electric suppliers available to serve the area with respect to reliability of service?*

This is not a consideration in this circumstance. The Red River Valley Units will not provide direct retail service in competition with electric suppliers in the area.

6. *Which of the available electric suppliers will be able to serve the location in question more economically and still earn an adequate return on its investment?*

This is not a consideration in this circumstance because the Red River Valley Units will not provide direct retail service in competition with electric suppliers in the area.

7. *Which supplier's extended electric service would best serve orderly and economic development of electric service in the general area?*

This is not a consideration in this circumstance. The Red River Valley Units will not provide direct retail service in competition with electric suppliers in the area.

8. *Would approval of the application result in wasteful duplication of investment or services?*

No. There is currently an unmet need for additional capacity on the Xcel Energy system to ensure reliable service to all the Company's customers within the five states the Company serves.

9. *Is it probable that the location in question will be included within the corporate limits of a municipality within the foreseeable future?*

No. The area under consideration for the plant site for the Red River Valley Units is not likely to be included within a municipality within the foreseeable future.

10. *Will the service by either of the electric suppliers in the area unreasonably interfere with the service or system of the other?*

This is not a consideration in this circumstance. The Red River Valley Units will not provide direct retail electric service in competition with other electric suppliers.

In summary, the Red River Valley Units satisfy the need requirements to be granted a CPCN.

XI. CONCLUSION

Xcel Energy respectfully requests the Commission make an advance determination of the prudence of the Company's proposal to add three natural gas combustion turbine generators to its system to meet its identified need for 150 to 500 MW of peaking capacity in the 2017-2019 time period. The Company also requests that the Commission grant a certificate of public convenience and necessity for the two natural gas combustion turbine generators that the Company proposes be located at a new Red River Valley plant near Hankinson, South Dakota.

Dated: April 26, 2013

Northern States Power Company

Respectfully submitted,

/s/
LAURA MCCARTEN
REGIONAL VICE PRESIDENT