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December 7, 2011

Hon. Richard C. Luis
Administrative Law Judge
Office of Administrative Hearings
P.O. Box 64620
St. Paul, MN 55164-0620

--VIA ELECTRONIC FILING--

Re: IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY
FOR A CERTIFICATE OF NEED
FOR THE BLACK DOG GENERATING PLANT REPOWERING PROJECT
MPUC DOCKET NO. E-002/CN-11-184
OAH DOCKET NO. 7-2500-22228-2

Dear Judge Luis:

Northern States Power Company respectfully submits the enclosed Motion to Withdraw Application and Request Pursuant to Minn. R. 1400.7600 for Certification of this Motion to the Minnesota Public Utilities Commission.

Consistent with your Order dated November 30, 2011, the Company requests that you schedule a Second Prehearing Conference.

Sincerely,

/s/

JAMES R. DENNISTON
ASSISTANT GENERAL COUNSEL

Enclosures
cc: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR A CERTIFICATE OF NEED FOR THE BLACK DOG GENERATING PLAN REPOWERING PROJECT.

MPUC DOCKET NO. E-002/CN-11-184
OAH DOCKET NO. 7-2500-22228-2

MOTION TO WITHDRAW APPLICATION; AND, REQUEST PURSUANT TO MINN. R. 1400.7600 FOR CERTIFICATION OF THIS MOTION TO THE COMMISSION

INTRODUCTION

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") respectfully moves to withdraw its application relating to the Company's March 15, 2011 request for a Certificate of Need ("CON") for approximately 450 MW of Incremental Capacity for the Black Dog Repowering Project with a proposed in-service date in 2016 ("Project"). This Motion to Withdraw is based on the Resource Plan Update which was filed on December 1, 2011 in Docket No. E-002/RP-10-825 showing that there is no longer a need for the Project as proposed. A copy of the Resource Plan Update filing is included as Attachment A to this Motion.

The Company also requests certification of this motion pursuant to Minn. R. 1400.7600, so that it can be directly addressed by the Commission.

Pursuant to Minn. R. 1400.6600, other parties who wish to contest the motion must file a written response and serve copies on all parties within ten working days of receipt of this pleading. A hearing is requested on the request for certification and on the Motion to Withdraw whether the motion is ultimately heard by the Commission or the Administrative Law Judge.

I. REVIEW OF THE UPDATE TO THE RESOURCE PLAN

The CON Application was based upon the Company's August 2010 Resource Plan filing (Docket No. E-002/RP-10-825), which in turn was based upon our 2010 forecast, that showed that the proposed Black Dog Repowering Project was the most cost-effective way to meet the identified need. In our June 14, 2011 Supplement ("Supplement") filed in the current docket, we provided the Spring 2011 forecast information and discussed how forecasts of reduced consumer demand made the timing analysis for the Project less certain. The Company recognized in the Supplement that, "It will be important to continue to monitor forecasts closely and to assess evolving economic conditions. If trends weaken further, it may be prudent to move more slowly and implement the project at a later time than January 2016."

As discussed in the Resource Plan Update (Attachment A), current economic data demonstrates further softening of demand along with reductions in our energy forecast. Under current forecasted conditions, we no longer see a capacity requirement in 2016 and can no longer support an additional long-term capacity resource as proposed in this docket. Rather, our current analysis suggests we will not need additional long-term capacity resources until at least 2018, and that it is more likely that the next resource should be a combustion turbine. Delaying the capital investment contemplated for our Black Dog Repowering Project is expected to reduce costs pressures for our customers. It is clear that we have adequate time to consider the best alternative for 2018 and beyond. We have committed to present updates in our next resource planning cycle which is currently proposed for Spring 2013.

II. MOTION TO WITHDRAW THE CON APPLICATION

As the analysis in our Resource Plan Update (Attachment A) shows, our most recent forecast no longer supports either the 2016 in-service date or the combined-cycle unit requested in the CON Application. The updated Resource Plan filing demonstrates the need to withdraw the CON Application. Accordingly, Xcel Energy moves to withdraw the CON Application.[1]

[1] Our work to date on the Black Dog Repowering Project has provided our customers with considerable value and has been reasonable under the circumstances. When we first began, all signs indicated a resource would be needed by 2016. Given the time needed to bring a substantial project like this to fruition, we moved forward, while always monitoring the situation to incorporate new information. These actions were prudent. Furthermore, by establishing a viable and cost-effective option to meet future capacity needs, most of the work already undertaken will be available for future use when it becomes clear future capacity is needed. Because the Commission does not make

III. REQUEST FOR CERTIFICATION OF THE MOTION TO WITHDRAW PURSUANT TO MINN R. 1400.7600

The Company also requests that the Motion to Withdraw be certified for direct consideration by the Commission. The legal standard for direct Commission review of a motion in a matter assigned to an administrative law judge ("ALJ") is set forth in Minn. R. 1400.7600, which states in pertinent part:

> 1400.7600 CERTIFICATION OF MOTIONS TO AGENCY.
> … Any party may request that a pending motion or a motion decided adversely to that party by the judge before or during the course of the hearing, other than rulings on the admissibility of evidence or interpretations of parts 1400.5100 to 1400.8400, be certified by the judge to the agency. In deciding what motions should be certified, the judge shall consider the following:
>
> A. whether the motion involves a controlling question of law as to which there is substantial ground for a difference of opinion; or
>
> B. whether a final determination by the agency on the motion would materially advance the ultimate termination of the hearing; or
>
> C. whether or not the delay between the ruling and the motion to certify would adversely affect the prevailing party; or
>
> D. whether to wait until after the hearing would render the matter moot and impossible for the agency to reverse or for a reversal to have any meaning; or
>
> E. whether it is necessary to promote the development of the full record and avoid remanding; or
>
> F. whether the issues are solely within the expertise of the agency.

The Resource Plan Update shows that the Company can no longer support the resource need as presented in this docket. Since the underlying need for the capacity is no longer present, it is not prudent to proceed with this docket. The Commission's referral Order did not contemplate this situation, and this motion should be sent to the Commission for its ruling.

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decisions regarding cost recovery in Certificate of Need proceedings, we will propose appropriate ratemaking treatment for these prudent costs in a separate filing.

Any single ground listed in the above rule can independently support a request for certification.[2] Each of these grounds is discussed immediately below:

A. Controlling Question of Law - Minn. R. 1400.7600(A)

At least one of the controlling questions of law is whether this matter should be dismissed where the Company can not sustain its burden of proof on the need for increased capacity. Given the update to the Resource Plan, it is clear that the Company can not sustain its burden of proof.

B. A Final Determination by the Agency on the Motion Would Materially Advance the Ultimate Termination - Minn. R. 1400.7600(B)

A final determination by the Commission would materially advance the ultimate termination. The results of the Resource Plan Update show that there is no need for the additional generation that this Project was meant to address and on this basis recommends that this case be closed. If the Commission determines that it is appropriate to end this docket, this would materially advance the ultimate termination of the case, and would do so without burdening the parties and the ALJ with the time, effort, and expense inherent in a contested case hearing.

C. A Delay Between the Ruling and the Motion to Certify Would Adversely Affect the Company - Minn. R. 1400.7600(C)

A delay in having the Commission consider the Motion to Withdraw would adversely affect the Company, as this would likely mandate that the parties proceed with a contested case hearing which would force the Company to devote substantial resources and time to advance a cause that is no longer needed.

Additionally, no party would be prejudiced by having the Commission directly consider the Motion to Withdraw.[3] In the event that the Motion to Withdraw

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[2] In addition to the disjunctive wording of the rule, see, for example, *In the Matter of Qwest Corporation's Conversion of UNEs to Non-UNEs*, P-421/C-07-370, where the Commission considered issues certified only under 1400.7600 (A) and (B).

[3] *See*, Order approving Certification, February 7, 2000, authored by then Administrative Law Judge Phyllis A. Reha, *In the Matter of The Exemption Application By Minnesota Power For A 345/230 kV High Voltage Transmission Line Known As The Arrowhead Project,* Minnesota Environmental Quality Board Docket No. MP-HVTL-EA-1-99, which noted that an additional factor supporting certification of a motion is if no party would be prejudiced by the modest delay involved with having a motion certified. A copy of this order is available at http://mn.gov/oah/multimedia/pdf/290112620.cert.pdf (accessed November 25, 2011).

is certified to the Commission, and the Commission then denied the Motion to Withdraw, the Company would agree to extend the case schedule to allow all parties sufficient time to conduct discovery and to prepare for a contested case hearing so that no party would be prejudiced.

D. Waiting Until After the Hearing Would Render the Matter Moot and Impossible for the Agency to Reverse or for a Reversal to Have Any Meaning - Minn. R. 1400.7600(D)

As emphasized above, the Motion to Withdraw should be heard and granted by the Commission. The benefits of direct review include having the parties avoid unnecessary time, effort, and expense being incurred in a contested case hearing in this docket in pursuing a generating resource which is no longer needed. If this matter proceeds to a contested case hearing, these benefits would be lost and rendered moot, and it would be impossible for the Commission to restore these lost benefits.

E. It Is Not Necessary to Promote the Development of the Full Record and Avoid Remanding - Minn. R. 1400.7600(E)

The Resource Plan Update makes it clear that the Company can not sustain its burden of proof, and no additional record on this point is needed. A full record is not needed for the Commission to consider the Motion to Withdraw since the Company has the burden of providing electrical service in its service territory, and the Company no longer projects a need for the generation resource at issue in this docket. If the Commission concludes that an additional record is needed, then this additional record can be focused on the Commission's concerns in light of these new developments.

F. The Issue is Solely Within the Expertise of the Agency – Minn. R. 1400.7600(F)

The companion to the CON Application is the site and route permit Application for the Project in Docket No. E-002/GS-11-307 ("Site and Route Permit Docket"). This Site and Route Permit Docket is pending before the Commission, not an ALJ. Contemporaneous with the filing of the Motion to Withdraw in the current docket, the Company is filing a similar motion in the Site and Route Permit Docket. For the sake of consistency, the two motions to withdraw pertaining to different aspects of the same Project should be decided together. It would be inefficient for the two motions to be decided differently, or on different timelines, given that both pertain to the same Project. A CON as a practical matter would not be effective where there is no site or route permit, and a site or route permit as a practical matter would not be effective where there is no CON for the Project. Given that the Site and Route Permit Docket is pending before the Commission, only the Commission has the jurisdiction or expertise to decide both motions together. Accordingly, the matter at issue here is solely within the expertise of the Commission.

CONCLUSION

The ALJ should certify the Motion to Withdraw for direct Commission review, because the several grounds supporting certification under Minn. R. 1400.7600 have been met. Additionally, the Commission should grant the Motion to Withdraw, since the Resource Plan Update shows that the Project is no longer needed.

Dated: December 7, 2011

Northern States Power Company,
a Minnesota corporation

RESPECTFULLY SUBMITTED,

/s/

BY: ______________________________

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(612) 215-4656

414 Nicollet Mall
Minneapolis, MN 55401

December 1, 2011

VIA ELECTRONIC FILING

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: RESOURCE PLAN UPDATE
DOCKET NO. E002/RP-10-825

Dear Dr. Haar:

On August 2, 2010, Northern States Power Company submitted to the Minnesota Public Utilities Commission our Resource Plan for the years 2011 to 2025. We recently requested an opportunity to provide a comprehensive update to the Resource Plan by December 1, 2011. The Commission granted our request through the Notice of Updated Filing and Extended Comment Period on October 10, 2011.

In compliance with the Commission's October 10, 2011 notice, we now submit our Resource Plan Update. As detailed in the Resource Plan Update, we believe continuing to implement many of the initiatives identified in the Original Action Plan is appropriate; however, significantly slower economic growth has delayed the timing of and likely size and type of certain resources. This filing updates our Resource Plan to:

- *Account for slower economic growth and the loss of wholesale customers;*
- *Capture benefits for our customers associated with lower resource needs; and*
- *Inform the Commission of changes to our plans for the current planning cycle.*

We direct stakeholders to the Resource Plan Update – Executive Summary for a high-level discussion of these updates.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission, and copies have been served on all parties on the attached service lists.

Please do not hesitate to contact me at (612) 330-6732 or james.r.alders@xcelenergy.com if you have any questions.

Sincerely,

/s/

JAMES R. ALDERS
DIRECTOR, REGULATORY ADMINISTRATION

Enclosure
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION FOR APPROVAL OF THE 2011-2025 RESOURCE PLAN

DOCKET NO. E002/RP-10-825

RESOURCE PLAN UPDATE

I. EXECUTIVE SUMMARY

A. Introduction

Northern States Power Company submits this update to our Resource Plan to the Minnesota Public Utilities Commission. In compliance with the Commission's October 10, 2011 notice, this filing provides a comprehensive update to our initial Resource Plan, including a revised Five-Year Action Plan designed to cost-effectively meet our customers' needs for electrical energy during the planning period.

As detailed in this filing, significantly slower economic growth has delayed the timing of and likely size and type of our next resource. This filing updates our Resource Plan to:

- *Account for slower economic growth and the loss of wholesale customers;*
- *Capture benefits for our customers associated with lower resource needs; and*
- *Inform the Commission of changes to our plans for the current planning cycle.*

Much of our proposed Five-Year Action Plan remains unchanged and continues to be implemented. This includes our successful effort to achieve 1.5% conservation and demand side management savings. We have also successfully executed our competitive bidding program to add 200 MW of additional wind power to our system and are exploring opportunities for adding wind generation prior to expiration of federal tax incentives, which will likely occur at the end of 2012. However, given the updated information in this filing, we propose the following changes to our initial Five-Year Action Plan:

- *Black Dog Repowering Project*. Our forecasts and refreshed analysis conclude the next generating resource is no longer needed in 2016. We have adequate time to continue monitoring economic conditions and their impact on the timing of our next generation addition. We intend to request withdrawal of the Black Dog Certificate of Need Application, which will be considered separately in the Black Dog Certificate of Need proceeding.

- *Prairie Island Capacity Upgrade Program*. We have made considerable progress toward completing the engineering to support the upgrade of the capacity of the Prairie Island generating plant. Based on current information, we have scaled back our estimate of achievable capacity increases at the plant. Our current base cost analysis suggests the capacity upgrade program remains cost effective. However, given our experience with the Monticello extended power uprate, other utilities' experiences with similar nuclear projects, and the ongoing analysis of regulatory requirements in the aftermath of the Fukushima Daiichi incident, we believe this project would benefit from further review and risk assessment. We recommend the Commission review our analysis in a separate Changed Circumstance docket before we proceed.

- *Wind*. It appears unlikely that the federal production tax credits for wind generation will be renewed at the end of 2012. We plan to reassess our wind power acquisition program after 2012 since we have adequate installed generation and renewable energy credits to maintain compliance with Minnesota Standards for several years.

We believe continuing to implement all other initiatives identified in the Five-Year Action Plan is appropriate.

Finally, we respectfully request that the Commission conclude this planning cycle based on our revised Five-Year Action Plan and schedule the next planning cycle to begin in the Spring of 2013.

B. Need for Resource Plan Update

A Resource Plan begins with a projection of customer demand for capacity and energy over the planning horizon. These projections of future needs serve as the foundation for determining the type and amount of resources that will be needed over the planning period. In developing these projections, we incorporate a variety of information from several internal and external sources. The most important information is fundamental data regarding the status of the economy and projections of economic growth. We also consider other relevant factors. In this case those include new information about nuclear capital investment costs, lower gas prices due to hydraulic fracturing, cost pressures as a result of the events at Fukushima Daiichi and the expiration of the federal production tax credit.

Since our initial filing in 2010, the pace of projected economic growth has changed substantially, and in some cases, is reflecting short-term contraction. As a result, we have reassessed future demand for capacity and energy on our system and our associated resource needs. Our reassessment directly affects the timing (and potentially the size and type) of a key resource investment identified in our initial filing – our proposed Black Dog Repowering Project, which is currently being considered in Docket E002/CN-11-184. Other information, such as our experience with the Monticello extended power uprate and our engineering work to date, suggests it is appropriate to reassess our previously approved Prairie Island extended power uprate ("EPU") to ensure it remains cost-effective. These two projects are discussed in more detail in this filing. Both the Black Dog and Prairie Island projects are at developmental stages where additional review can occur, which will allow us to make the most cost-effective resource decisions for our customers. This filing also addresses the upcoming expiration of the federal production tax credit, the potential for increasing wind generation costs, and our ability to used installed generation and banked renewable energy credits rather than continuing to add wind to avoid higher costs.

While our update is driven by the desire to reexamine a few key capital investments, much of our original Resource Plan and Five-Year Action Plan does not change. Many initiatives included in our Five-Year Action Plan are providing significant value to our customers, even in light of our revised economic and forecast expectations. The remainder of this summary provides additional information about:

- Economic Conditions and Revised Forecasts
- Black Dog Units 3 and 4
- Prairie Island EPU
- Post-2012 Wind Procurement Strategy
- Original Action Plan Initiatives
- Revised Five Year Action Plan

C. Economic Conditions and Revised Forecasts

1. Economic Conditions

The projections for customers' future demands for capacity and energy are highly dependent on several macroeconomic indicators, the three most important being Gross Domestic Product ("GDP"), generally considered the broadest measure of economic activity; Minnesota Gross State Product ("GSP"), which measures the economic output of Minnesota; and Minnesota Households, which generally indicates how many new Minnesota residential customers will be added. When we initially filed our Resource Plan, we projected customers' future demand for capacity and energy based upon economic data from the first quarter of 2010. At that time, both Minnesota and the country overall appeared to be on the path to recovery. Our initial Resource Plan was therefore based upon an expectation of continued steady growth for Minnesota and the overall economy.

Based on the performance of the overall economy, the forecasting companies we rely upon (*i.e.*, Global Insight and others) predicted growth for our key macroeconomic indicators throughout the Resource Plan horizon. For example, at the time of our initial filing, we used the following assumptions for our key macroeconomic indicators:

Indicator	**Initial Resource Plan Projection**
2011/2012 Average GDP Growth Rate	3.3%
2011/2012 Average Minnesota Gross State Product Growth Rate	2.8%
2011/2012 Average Minnesota Household Growth Rate	1.1%

Source: Global Insight

After we submitted the initial Resource Plan, underlying economic conditions began to change. Nationally, growth decreased over the second half of 2010, registering slightly above 2 percent growth for the remainder of the year. In response to continued slower than expected economic performance, forecasters have continued to revise each of our key macroeconomic indicators downward, including for Minnesota:

Indicator	**Initial Resource Plan**	**Black Dog CON Update**	**Updated Resource Plan**
2011/2012 Average GDP Growth Rate	3.3%	2.6%	2.2%
2011/2012 Average Minnesota Gross State Product Growth Rate	2.8%	2.6%	1.7%
2011/2012 Average Minnesota Household Growth Rate	1.1%	1.1%	0.9%

Source: Global Insight

The downward revisions have not been limited to future expectations of macroeconomic performance; estimates of actual results have also been reduced. For example, in August 2011, the U.S. Bureau of Economic Analysis substantially revised its estimate of actual GDP for 2007 through the first quarter of 2011.

Bureau of Economic Analysis[1] Annual Revision of the National Income and Product Accounts		
	Original Estimate	Revised Estimate
2007–2010 Average Real GDP Annual Rate of Change	>(0.1)%	(0.3)%
Fourth Quarter 2007 – First Quarter 2011 Average Real GDP Rate of Change	0.2%	(0.2)%

While it is not uncommon for historical indicators to be revised, these revisions are unique in that they change the overall direction – from growth to contraction – and revise declining numbers downward further. Because both forward-looking and backward-looking macroeconomic indicators play such an important role in our projections of customers' future needs, these revisions necessitated an update to our forecasts.

We updated our forecasts in the Spring of 2011 based upon the then-existing macroeconomic expectations. This forecast indicated some softening of the overall economy, but still showed overall growth in our customers' requirements. On June 14, 2011, we provided an updated projection of our customers' demand for capacity and energy in our Black Dog Repowering Project Certificate of Need proceeding ("Black Dog CON"). This projection showed lower demand for capacity and energy than what was included in our initial Resource Plan. Our revised projection reflected

[1] BUREAU OF ECONOMIC ANALYSIS, *Annual Revision of the National Income and Product Accounts* at 6 (Aug. 2011), *available at* http://www.bea.gov/scb/pdf/2011/08%20August/0811_nipa_annual_article.pdf.

a combination of reduced firm wholesale municipal load, lower actual peak demand in 2011, and updated macroeconomic performance indicators. We also noted in the June update that if the economy showed further signs of weakness, it could cause us to change our recommendations. We committed in that filing to continue to closely monitor the situation and provide the Commission with additional updates as circumstances evolved.

Since we provided these projections in the Black Dog CON proceeding, the economy has continued to soften. In particular, the key macroeconomic indicators we rely upon in projecting customers' future demand for capacity and energy have been revised downward to show:

- Lower Minnesota industrial production;
- Slower recovery of commercial and industrial load;
- Lower Minnesota employment growth for 2011 and 2012; and
- Lower housing permits for 2011 and 2012.

We now expect 0.7% annual demand growth and 0.5% annual energy growth over the Resource Plan horizon, down from 1.1% and 0.9%, respectively, included in our initial filing. The magnitude of the reduced forecast is such that it prompts us to reconsider some components of our Five Year Action Plan. Thus, this update presents our new sales forecast and provides the Commission with recommendations on some revisions to our plans going forward.

2. *Revised Forecast*

Our current expectations are lower than what was included in the initial filing, reducing our projection of customers' future demand for capacity in 2016 by approximately 500 MW from our initial Resource Plan filing. These new expectations impact the timing and type of required generation additions. In light of our revised expectations, we currently have sufficient generation resources to meet customers' needs through 2018. Accordingly, we will seek authorization in other proceedings to withdraw our currently-pending application for repowering of Black Dog Units 3 and 4 and ask the Commission to reevaluate the planned EPU at Prairie Island.

D. Drivers for this Filing

1. *Black Dog Units 3 and 4*

We have continued to assess the repowering of Black Dog Units 3 and 4. Based on the revised economic outlook, we no longer expect a 2016 capacity deficit. As such, we do not believe it is necessary to pursue the repowering of Black Dog Units 3 and 4 for a 2016 in-service date. Instead, it provides more value to our customers to delay the repowering and rely upon existing generation to meet our needs.

We do not expect additional generation will be needed on our system until 2018. As a result, we have time to continue assessing the best resource addition options for our customers. Deferring the capital investment required for the repowering (or delaying the proposed alternative) will save our customers money and is the best course of action at this time. Through a separate filing in our Black Dog CON proceeding, we will request authorization to withdraw our application for approval of the Black Dog Repowering Project.

To date, we have performed significant preliminary development and permitting work on Black Dog and believe that work will have continuing value. These efforts were appropriate in order to develop and advance the certificate of need proceeding and to be prepared for implementing the project in a timely manner, if approved. We have also reasonably incurred costs to plan and develop the Black Dog project. We will address preserving those costs for recovery in another docket.

2. *Prairie Island EPU*

Since our initial Resource Plan filing, changes have occurred regarding our EPU at Prairie Island. Based on our experience with the EPU project at the Monticello Nuclear Generating Plant, other utilities' recent experiences with EPUs, and the Nuclear Regulatory Commission's ("NRC") review of post Fukushima Daiichi issues, we believe the most prudent course of action is to consider the appropriateness of continuing to pursue the EPU at Prairie Island. We plan to initiate such review in a separate docket through a Changed Circumstances Filing in 2012.

We addressed the additional costs related to the life-cycle management ("LCM") and EPU work for Monticello as a part of our currently-pending electric rate case. Some of the additional costs stem from the fact that actual implementation of EPU/LCM at Monticello is more labor and capital intensive than we initially estimated. We are considering the risk of similar developments in our EPU at Prairie Island.

As part of this filing, we have made a preliminary reassessment of the cost effectiveness of the EPU program for Prairie Island based on changes known at this time. To date we have gained an additional 18 MW of generation at Prairie Island through work already authorized by the NRC. Additionally, significant project engineering work has been advanced and we recently received bids from vendors for various parts of the LCM/EPU program at Prairie Island. Based on our engineering work and review of bids, we are evaluating capital costs and performance of various components of the EPU program at Prairie Island. Our current base cost analysis indicates only 117 MW of the remaining 146 MW of generation that was originally expected to be added as a result of the EPU should be pursued if it continues to be cost effective.

Finally, as EPU licensing has evolved and in light of the impacts of Fukushima Daiichi, the NRC is currently considering additional application requirements. It is also assessing whether to require additional improvements to address accident analyses, which may expand the scope of current EPU projects. An example of this additional review was noted by the Company in our November 22, 2011 Changed Circumstances Filing for the Monticello EPU. Although Prairie Island is a different design, and should be less affected than Monticello, we believe NRC review will be longer than anticipated. Thus, we are assessing the risk of further cost increases.

Before we proceed further with the Prairie Island EPU project we believe it would be appropriate to present our analysis of all of these issues in more detail through a Changed Circumstances Filing. This will provide an opportunity for the Commission and other interested parties to understand the current cost projections for the LCM/EPU project, reassess the risks of EPU investment, and determine whether the Prairie Island EPU continues to be in the public interest given all considerations. In the meantime, we plan to carry out our LCM program at Prairie Island, with various activities that support the additional 20 years of licensed operations and fuel storage recently approved.

E. Post-2012 Wind Procurement Strategy

Consistent with our initial filing, we issued a Request for Proposal ("RFP") for up to 250 MW of wind energy to be in service by the end of 2012 on September 16, 2010. We are pleased to report that this RFP process was a significant success.

We received 143 proposals on 106 sites comprising 9,189 MW of distinct resources. As a result of that successful process, we entered into a power purchase agreement ("PPA") with Geronimo Wind Energy for the 200 MW Prairie Rose Wind Farm, which was approved by the Commission on November 10, 2011.[2] The Prairie Rose transaction also includes an option for the Company to take an additional 100 MW of generation, subject to Commission review and approval, providing us with the flexibility to capture additional generation if market conditions warrant.

[2] *See* Docket No. E002/M-11-713.

As evidenced by the bids we received in this RFP, wind developers significantly reduced the price of project proposals in 2011. The decrease relates in part to lower project development costs, but also significantly reflects the impact of the pending expiration of the federal Production Tax Credit ("PTC"). The PTC significantly reduces the cost of wind generation, without which it may not be a cost-effective investment. However, the PTC is set to expire at the end of 2012 and extension appears unlikely at this point. Thus, post-2012 wind projects may be significantly more expensive if they are unable to rely upon the availability of the PTC.

We have explored the opportunity to procure low-cost wind generation between now and the expiration of the PTC, but the short timeframe also created significant construction, permitting and financing challenges. The Company will continue to explore opportunities to procure as much as 300 MW of additional wind generation prior to the PTC expiring. While we are eager to obtain low priced, cost-effective wind generation for our customers, we seek to avoid the risks of incomplete or failed projects. We will, of course, report to the Commission if we are successfully able to contract for additional wind generation prior to the PTC deadline.

Currently we have significant installed generation and a bank of renewable energy credits that we can use to satisfy our renewable energy requirements. To the extent the PTC expires and wind prices increase as expected, we will be able to rely on our installed generation and banked RECs rather than adding uneconomic wind generation. Drawing upon our installed generation and banked RECs will allow us to wait for the market to settle and reevaluate market conditions in our next Resource Plan filing. This allows us to evaluate market conditions and acquire wind only if it is a cost-effective resource for our customers. Thus if prices do not spike or cost-effective opportunities become available, we may add wind generation. In this update, we have modeled various wind scenarios to reflect our options. Our revised Five-Year Action Plan reflects that we will not add more wind generation after 2012 unless it is cost-effective for our customers.

F. Contingency Planning

In previous resource plans, we discussed a contingency process to address the potential for more rapid capacity expansion than envisioned in a five-year action plan. Although this update proposes that it is appropriate to delay a significant capital investment at Black Dog due to slower economic growth, the market volatility and the potential for a faster economic rebound should be considered as well. There have been signs of a strengthening economy at various times over the past two years and we certainly desire that more robust economic growth materializes. In the event of faster growth, we can always rely on the energy market to meet short term needs;

however, it is also important to consider a contingency that adds a physical resource to avoid being overly reliant on the market. We believe it is time to enhance contingency planning by considering opportunities for developing engineering, permitting, and equipment reservations for physical generation. For instance, this could allow us to modify the work undertaken to date for the Black Dog project. Such a discussion of appropriate contingency mechanisms could also address appropriate rate mechanisms to encourage advance preparation. Overall, a contingency process would provide customers an important hedge against exposure to market conditions and allow us to continue appropriate long-term planning activities.

G. Conclusion

The proposed, revised Five-Year Action Plan provides relevant updated information to reflect changes that have occurred since we originally filed our Resource Plan in 2010. As a result of this update, we believe certain key investments should be delayed or reviewed, while the remainder of our Five-Year Action Plan continues. The key changes allow us to maximize benefit for customers and ensure that we meet their needs in a cost-effective manner. By implementing the changes discussed above, our revised Five-Year Plan delays significant capital expenditures until additional resources are needed on our system. Meanwhile, elements of our Plan continue to be prudent and have already delivered substantial customer value.

Therefore, we ask the Commission to conclude this planning cycle by approving our revised Five-Year Action Plan, including the following changes from our initial proposed Five-Year Action Plan:

- Withdrawal of our Black Dog Repowering Project, to be assessed in a separate docket;
- Additional assessment of the Prairie Island EPU, to be conducted in a separate docket;
- Our revised post-2012 wind procurement strategy; and
- Further development of a contingency plan.

We also ask the Commission to approve as part of our revised Five-Year Action Plan those portions of our initial Five-Year Action Plan that are already providing value to our customers, including:

- *DSM*. In 2010, we significantly exceeded our DSM goals, achieving 415 GWh in savings, which translates into 1.35% of sales. As part of our initial filing, we indicated we wanted to expand our savings goals to 1.5% and we are on track to exceed that goal for 2011. DSM continues to deliver value for our customers and we are excited to continue working with our stakeholders to achieve 1.5% DSM energy savings as part of the revised Five-Year Action Plan.

- *Manitoba Hydro.* On May 26, 2011, the Commission approved three previously identified agreements with Manitoba Hydro.[3] Extending our relationship with Manitoba Hydro will allow us to continue providing customers with economical service from renewable resources.

- *Monticello EPU.* We continue to include the EPU at the Monticello as part of the revised Five Year Action Plan.

- *Wind.* We have successfully procured 200 MW of wind power pursuant to the RFP process and we are exploring other wind opportunities for 2012 completion.

Finally, we request that the Commission authorize the Company's next planning cycle to begin in the Spring of 2013.

II. REVISED FORECAST AND RESOURCE NEEDS

The process of resource planning is an important step in achieving our goal to provide our customers with safe, reliable, cost-effective service. As part of our Resource Plan, we engage in a forward-looking process to assess both our customers' electric needs and the resources required to meet those needs.

Resource planning is an ongoing task and many variables affecting resource needs can change over a planning horizon.

The country entered an economic recession in early 2008 that lasted eighteen months. Due to the volatility in the economy and its impact on customers' future energy needs, we have updated our analysis of demand for capacity and energy on our system.

When we filed our initial Resource Plan, we recognized the economic environment at that time, which could further change, and the affect this may have on our customers' future energy needs. We therefore committed to monitor the economic environment. In subsequent months we assessed the impact of revised historic and forward-looking data and updated our forecasts. This past June, we provided our first forecast revision

[3] *See* Docket No. E002/M-10-633.

to the Commission and other interested stakeholders as part of the Black Dog CON proceeding. We now provide our most recent forecasts and the data that supports our analysis.

While we propose modifications to our Resource Plan to account for current economic conditions, we recognize the economy is still volatile. We therefore remain committed to monitoring the economic environment and analyzing its impact on our resource needs. As we learn more about the economic conditions affecting the country, we will continue to adjust our projections as often as is needed to assure that we prudently manage our business and resources for the benefit of our customers.

The remainder of this section presents the data supporting our revised forecasts and our current projection of customers' future demand for capacity and energy. First, building upon the information included in the Executive Summary, we provide data which confirms that the economy did not, and likely will not, grow as we believed it would when the initial Resource Plan was filed. Next, we discuss an additional driver that further lowers our demand forecasts. We then provide our revised forecasts and explain the impact the downward adjustment will have on our resource needs.

A. Changed Economic Expectations

Prior to filing our initial Resource Plan, key economic indicators suggested that our country was emerging from the 2008 recession. As early as April 2009, forecasters were predicting GDP would grow by approximately 3.2 percent in 2010 and 3.6 percent in 2011. Though actual results for the fourth quarter of 2009 showed a slight decline, forecasts developed throughout the first half of 2010 continued to show moderate GDP growth for 2011 and 2012. Long-term economic indicators projected similar growth for the economy throughout this Resource Plan horizon. As a result, we based our initial Resource Plan upon an expectation of continued steady growth of approximately 2.5 percent for Minnesota and the overall economy between 2011 and 2018.

Based on the key macroeconomic indicators discussed in the Executive Summary and other relevant information, we forecasted 1.1% annual growth in system peak demand and 0.9% annual growth in median net energy in our initial Resource Plan filing. We also presented a limited Five-Year Action Plan which included, among other things, issuing the RFP for 250 MW of wind power, the Black Dog Repowering Project, the Prairie Island EPU project, and on-going evaluation of options for addressing potential peaking resource needs in the immediate future. We recognized, however, that our forecasts could be subject to change if the country's economic recovery did not materialize as experts predicted.

After our initial Resource Plan was filed, economic experts throughout the country determined that the recession was more severe than initially understood and the country was recovering at a slower rate than expected. Forecasters revised several key economic indicators downward, with Minnesota being hit hard:

Indicator	Initial Resource Plan	Black Dog CON Update	Updated Resource Plan
2011/2012 Average GDP Growth Rate	3.3%	2.6%	2.2%
2011/2012 Average Minnesota Gross State Product Growth Rate	2.8%	2.6%	1.7%
2011/2012 Average Minnesota Household Growth Rate	1.1%	1.1%	0.9%

Source: Global Insight

As explained in the Executive Summary, economists also began revising historic indicators downward. For example, in August 2011, the U.S. Bureau of Economic Analysis substantially revised its estimate of actual GDP, as measured from 2007 through the first quarter of 2011.

Though these changes were substantial, many of the strategies outlined in our Resource Plan still appeared to be necessary. The new economic data, however, could potentially justify delaying certain projects, which would mitigate short-term rate impacts. We first communicated our understanding about the impact slower economic growth was having on our demand forecasts to the Commission and other interested stakeholders in the Black Dog CON docket. On June 14, 2011, we provided an updated projection of our customers' future demand for capacity and energy. After using actual 2010 weather-normalized peak demand and the best economic data available at the time, our 2011 forecast for median peak demand was approximately 175 MW lower than what was included in our initial Resource Plan filing. Instead of the expected steady economic growth, we observed lower demand for capacity and energy due to a continued softening of the overall economy.

The June filing also addressed that all of our Wisconsin municipal wholesale customers and all but one of our Minnesota municipal wholesale customers decided not to renew their service agreements. This represents a 229 MW reduction in demand by 2014. We committed to closely monitor our expectations of our customers' future needs, as further changes could cause us to modify our recommendations relating to future resources.

B. Revised Forecast

Unexpected setbacks to the country's economic recovery and more significant wholesale municipal customer attrition have substantially changed our expectations for future resource needs. In response, we revised our forecasts for this Resource Plan, using the same key demand and forecast variables and forecast methodology as was described in our initial Resource Plan filing.

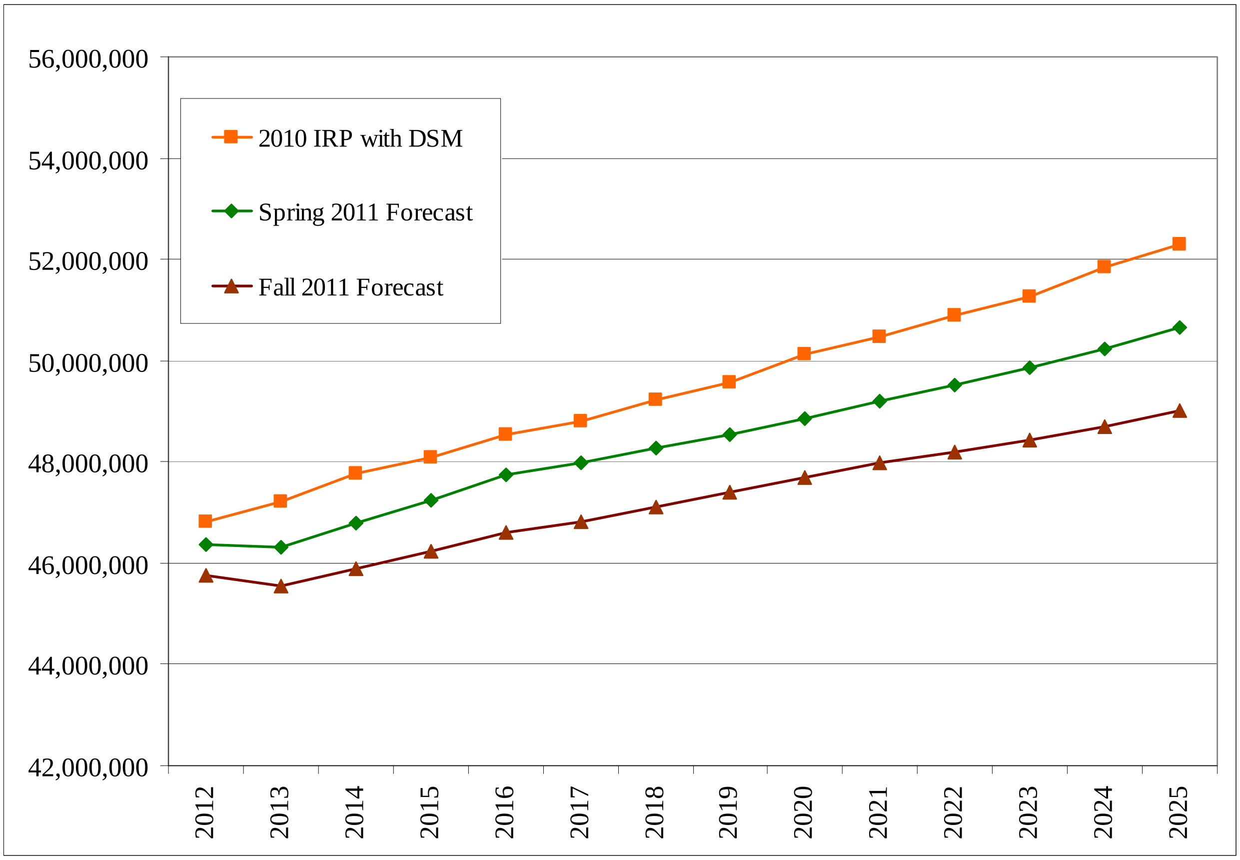
1. *Comparison of System Peak Demand and Median Net Energy Forecasts*

The table and graphs below illustrate the progression of our system peak demand and median net energy forecasts over time.

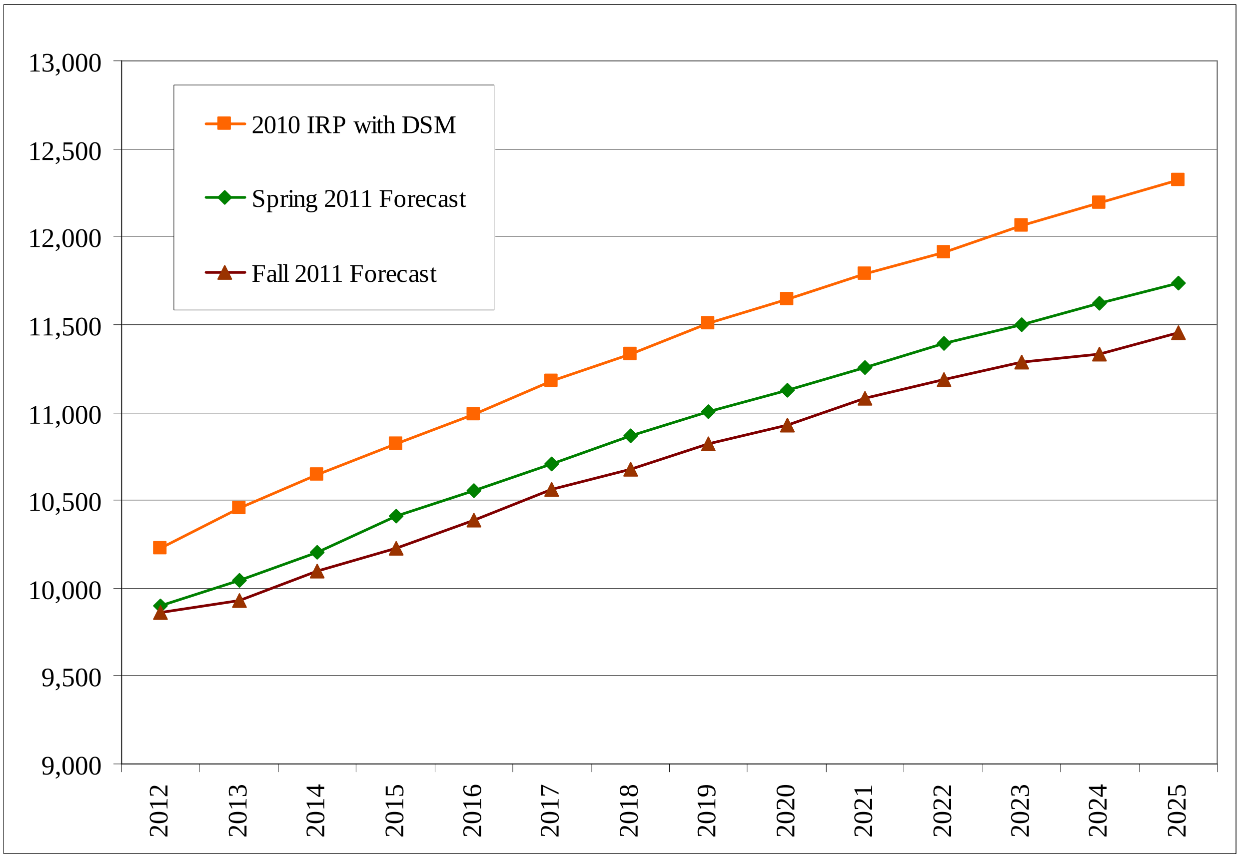
Forecast	**Annual Growth in System Peak Demand**	**Annual Growth in Median Net Energy**
Initial Resource Plan (June 2010)	1.1%	0.9%
Black Dog CON Update (June 2011)	0.9%	0.7%
Resource Plan Update (September 2011)	0.7%	0.5%

A comparison of the three forecasts is also shown in revised Figures 3.6 and 3.7 below.

Revised Figure 3.6
Net Energy Requirements (MWh)
Median (50th Percentile) Forecast
Comparison of Current and Previous Energy Forecasts



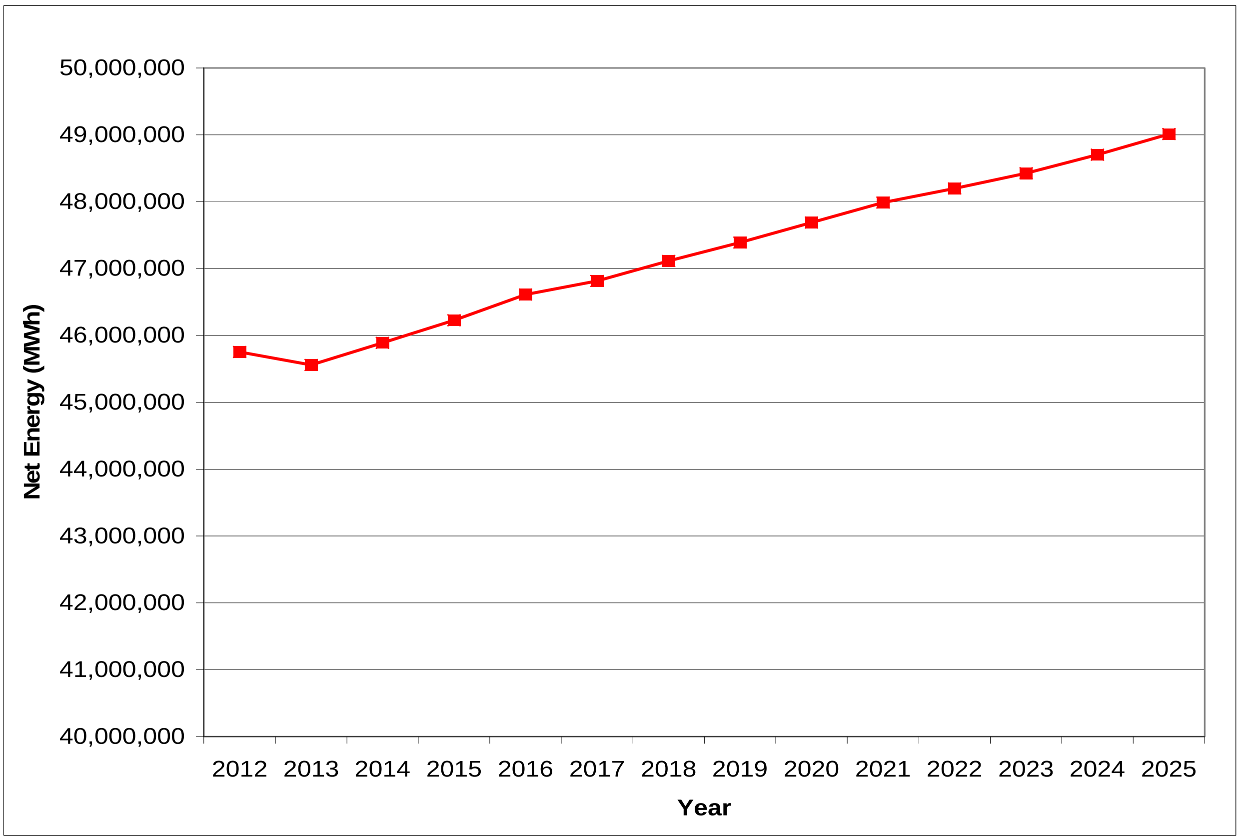
Revised Figure 3.7
Base Peak Demand (MW)
90th Percentile Forecast
Comparison of Current and Previous Demand Forecasts



2. *Base Energy Forecast*

In light of current information, we now expect our customers' demand for energy to increase at an average annual growth rate of 0.5% between 2011 and 2025. This compares to our original forecast of an average annual growth rate of 0.9%. The revision is based on an expected change in the annual average increase of electric energy requirements. See Revised Figure 3.1 below.

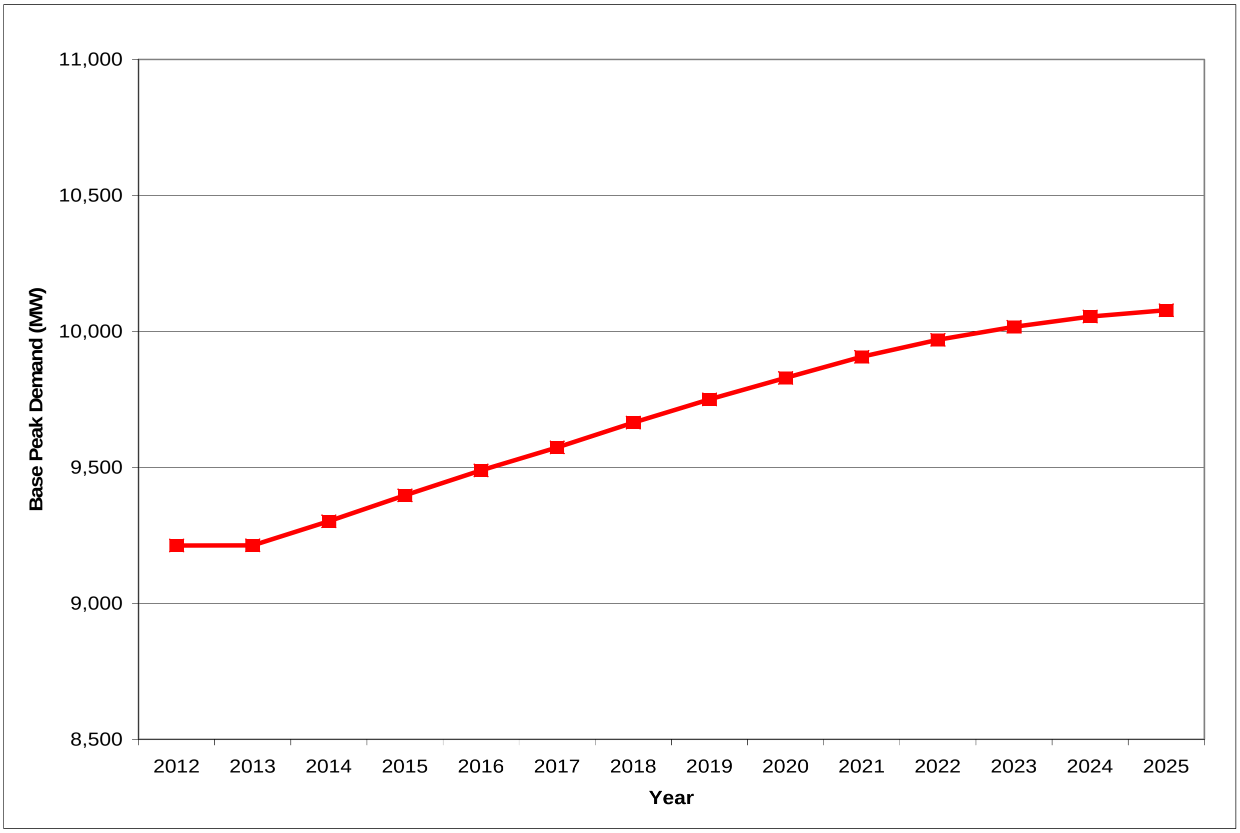
Revised Figure 3.1
Median Net Energy (MWh) NSP Total System
(Includes 1.5% Retail Sales DSM Adjustment)



3. *System Peak Demand Forecast*

Our updated base peak demand forecast, which reflects conservation efforts through 2010 but not the Company's load management programs, now projects 0.7% average annual growth in median base peak demand. This compares to our original forecast of an average annual growth rate of 1.1%. Over the planning period, annual peak demand now increases at a lower rate each year in the revised forecast.

Revised Figure 3.2
Median Base Summer Peak Demand (MW) NSP Total System
(Includes 1.5% Retail Sales DSM Adjustment)



4. *Forecast Variability*

To assess the potential variability embedded in our forecasts, we developed probability distributions for the peak demand and energy requirements using the same methodology discussed in our initial Resource Plan. Based on Monte Carlo simulations, there is now a 90% probability that the net energy will be less than 53,406,963 MWh in 2025. There is only a 10% probability that the net energy will be less than 44,622,960 MWh. While these probabilities are intended to bolster confidence in our forecasts, prudent planning always requires us to retain flexibility in our resource portfolio so we can address scenarios which may or may not unfold.

C. Affect on Resource Needs

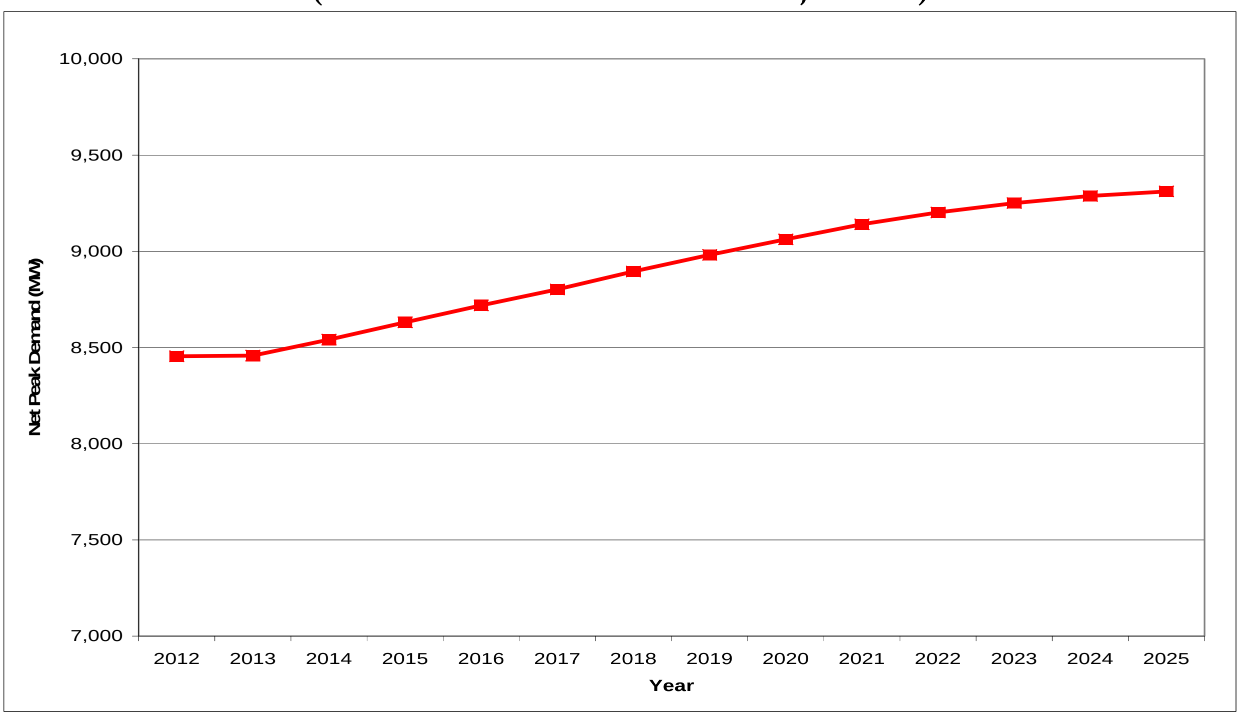
While many of the resources outlined in our initial Resource Plan are still needed, the discussion below explains our resource needs in light of our revised forecasts.

1. *Total Load Obligation*

As part of the initial Resource Plan, we provided a detailed discussion regarding the methodology and general assumptions used to develop our resource needs. For purposes of this update, our methodology and assumptions, except for those that changed as a result of slower economic growth and the departure of Wisconsin and Minnesota municipal customers, remain the same.

Our updated median net peak demand forecast increases at an average annual rate of 0.3% over the 2011 – 2025 planning period, which compares to an average annual rate of 1.2% that was forecasted as a part of our original filing. Additionally, the revised net peak demand forecast increases at an average of 31 MW annually. See Revised Figure 3.8 below.

Revised Figure 3.8
Medium Net Summer Peak Demand NSP System
(Includes 1.5% Retail Sales DSM Adjustment)



2. *Supply Resources*

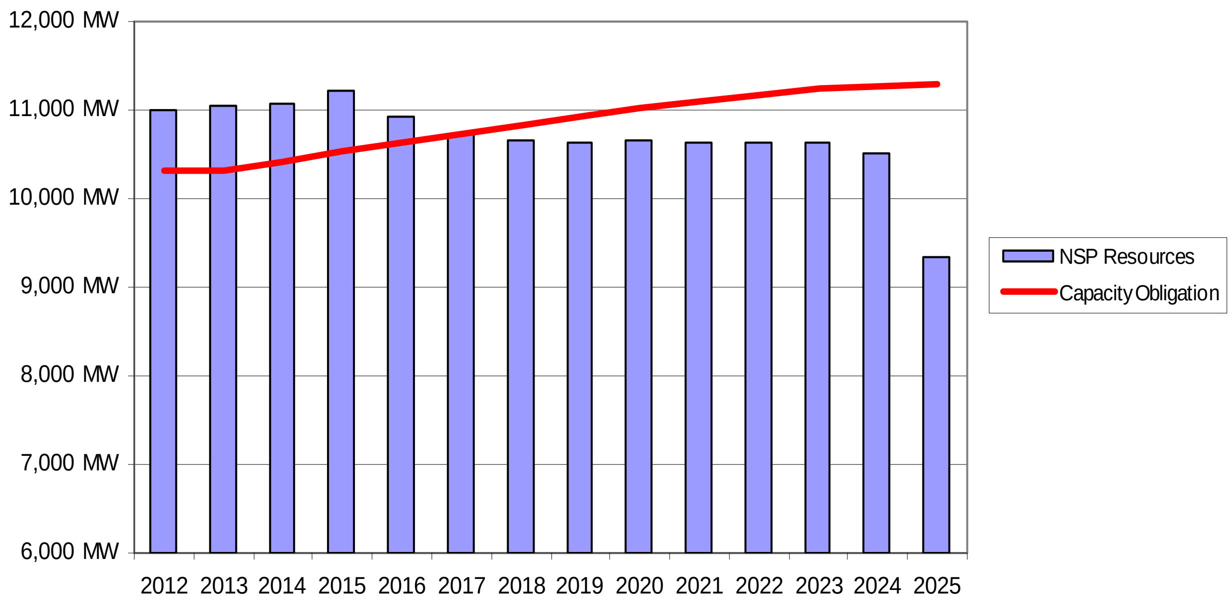
Based on our updated forecasted demand and expected available resources discussed above, we now anticipate new production capacity will be needed starting in 2018. This is three years later than indicated in our initial filing and provides us with additional time to assess the appropriate resources to fulfill our customers' needs.

The delay in timing of the need for new production, and the delay in incurring additional costs, benefits our customers.

3. Generation Requirements

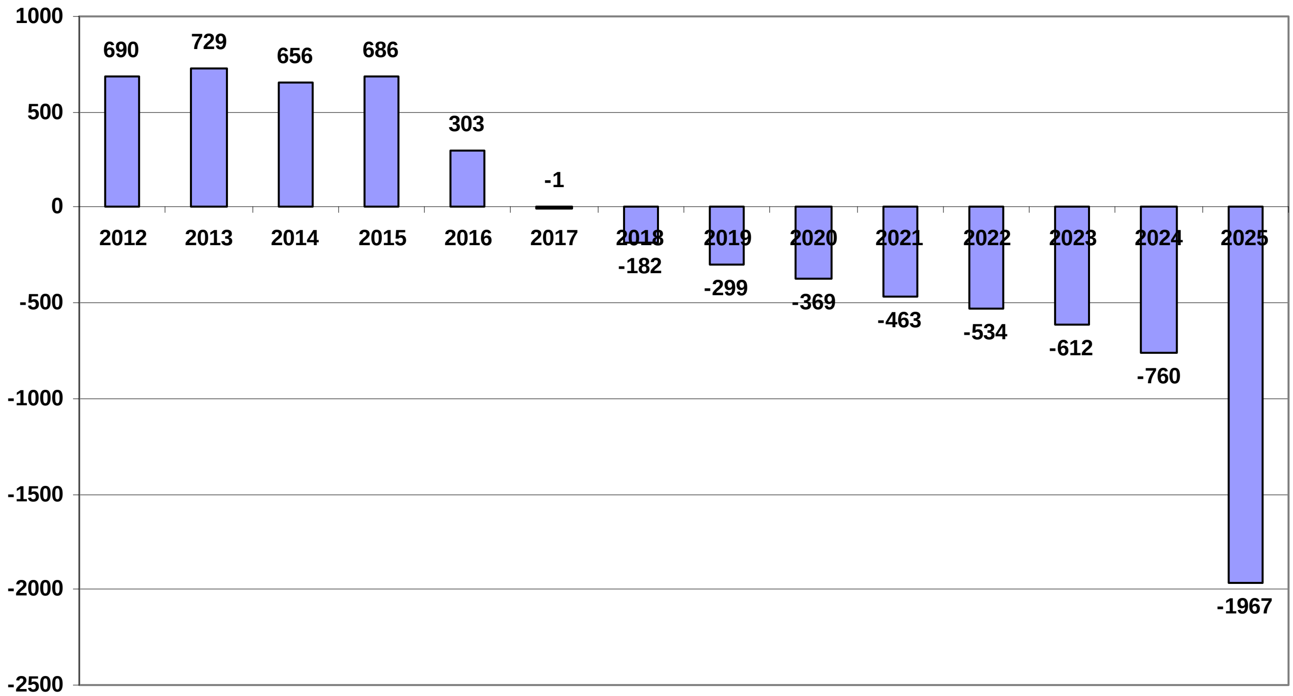
Revised Figure 3.10 presents an updated comparison of our forecast of production capacity requirements compared to existing generation resources and pending generation acquisitions.

Revised Figure 3.10
Requirements and Resources 2011-2024



Revised Figure 3-11 shows our projected resource needs for the planning period.

Revised Figure 3.11
Resource Needs by Year



In our initial filing, we expected to have surplus generation through 2013 with a deficiency emerging in 2014. As shown above, we now expect to have a surplus through 2016 with a deficiency emerging, in earnest, in 2018.

While the resource needs discussed above reflect our best assessment of our customers' future demand for capacity, uncertainty still exists. The pace of economic recovery remains uncertain, and as a result, our expectations may continue to change over the next several years. Thus, we believe it is important to consider a contingency process that allows us to be prepared to add capacity quickly in the event economic recovery occurs stronger and faster than currently anticipated. In that event, we want to be prepared to cost-effectively meet capacity and energy needs of our customers.

D. Conclusion

Resource planning is a continual process in which we address our customers' future needs in a cost-effective manner. Our customers' needs, however, can change depending on multiple factors, including the strength of the economy. Our initial Resource Plan was developed against a back-drop of an economic recession coupled with a volatile recovery. At the time, we appreciated the potential for this uncertainty and therefore have monitored key economic indicators. We now expect growth in demand of 0.7% per year and growth in energy of 0.5% per year over the 15-year planning period. The predicted rates assume we maintain DSM savings at 1.5% of retail sales. Comparing our projections to our available resources, we anticipate a need for additional generating resources starting in 2018. The delay in timing of new resources to meet our customers' needs allows us to defer additional capital costs.

III. MODELING AND PLAN DESCRIPTION

A. Baseline Assumptions

Our base assumptions are similar to those used in the initial Resource Plan filing, updated for current values:

Forecast

We plan to meet the 50% probability level of forecasted peak demand, and the 50% probability level of forecasted energy requirements.

Existing Fleet

- Cost and performance assumptions are consistent with historical data.
- Costs are escalated based on corporate estimates of expected inflation rates.
- Continued operation of our Sherco[4] and King generating stations throughout the study period.
- Retirement of our Prairie Island nuclear generating station at the end of its proposed license renewal (2033, 2034), and retirement of Monticello at the end of its current license (2030), and for the purposes of this planning document and analyses, replacement with new nuclear generation.
- Retirement of other facilities at their current expected end of life if within the Resource Planning period, unless we have specifically included costs of life extension.[5]
- Continuation of our existing power purchase contracts until their contractual termination dates.

[4] As noted in this update, we are investigating a recent incident at Sherco Unit 3. At this time we are not proposing any change to our Resource Plan because of this incident and consequently have not changed the way we model this generation.
[5] The one exception to this assumption is with regard to our Sherco Units 1 and 2. These facilities reach the end of their book lives in 2023. However, we are initiating a life extension study for these units, and are assuming, for the purposes of this analysis, that they continue to operate beyond 2023.

- Continued operation of our hydroelectric resources based on historical performance.

Renewable Energy

- Expiration of the PTC at the end of 2012.
- No additional wind generation added to the system after 2012, with a sensitivity to add 900 MW of wind generation between 2013 and 2020.
- Accreditation of wind resources based on Midwest Independent System Operator, Inc. planning reserve credit allocation (currently 12.9%).
- Additional ancillary service charges for wind based on the 2006 Minnesota Wind Integration Study.

Emissions

- Emission rates for existing and planned resources consistent with historical and expected performance.
- Cap and trade permit systems for SO_2, and NOx.
- No costs for carbon dioxide, but with sensitivities for CO2 values at the Commission's mid- and high-level estimates, plus a "late" CO2 scenario with costs starting in 2018.
- We did not incorporate the Commission's externality values for specified emissions as a base assumption, but included those high and low externality values as sensitivities.

We also updated the costs of our generic units. A list of our current assumptions is included in Attachment A.

In developing the updated proposed Five Year Action Plan, we analyzed several components to determine their cost effectiveness. As discussed in this update, we are assessing the Prairie Island EPU program given updated costs and potential delay scenarios. We also reanalyzed our need for the Black Dog Repowering Project, testing this project in several different years and optimizing the model to determine the timing and resource under a number of scenarios. As in the initial Resource Plan, we also updated scenarios that did not include our wind expansion plan, and scenarios that meet our North Dakota and South Dakota requirements.

B. Updated Proposed Five-Year Action Plan

Our updated plan builds on elements from the initial Resource Plan by including the following components:

- Completing the capacity uprate project for Monticello;
- Proceeding with EPU project for Prairie Island, subject to the outcome of our forthcoming Changed Circumstance filing;
- Withdrawing our request for a Certificate of Need for the Black Dog Repowering Project and reassessing the timing and need for additional combined cycle generation as part our next resource planning cycle;
- Retiring existing Black Dog Units 3 and 4 by 2016;
- Adding new combustion turbines to our system beginning in 2018;[6]
- Optimizing capacity additions for the remainder of this resource planning period;
- Flexible timing of wind additions and using installed generation and existing RECs to ensure the best value to our ratepayers; and
- Building our DSM programs to sustain savings of 1.5% of annual sales.

Updated Table 4.1 summarizes the expansion plan for the base scenario.

Table 4.1
Proposed Plan Expansion Plan

Year	Planned Additions	Combined Cycle	Combustion Turbine	Supercritical Pulv. Coal	Wind
		Generic Additions			
2011					
2012	Wind 32 MW				
2013	Wind 32 MW				
2014					
2015	PI EPU 58 MW MH 375 MH 350				
2016	PI EPU 58 MW				
2017					
2018			195 MW		
2019			195 MW		
2020			195 MW		
2021	MH 125				
2022					
2023			195 MW		
2024			195 MW		
2025		729 MW			

[6] The Strategist modeling shows a capacity need in 2018. At this point, however, the modeling does not establish a clear preference for the type of generation that best meets that need. As a result, we propose to continue to monitor and update our assumptions, and identify the most reasonable resource for 2018 in our next Resource Plan, which we are proposing to commence in Spring 2013.

As discussed in this update, we have significant installed capacity and RECs to meet the Minnesota renewable energy standard. This gives us considerable flexibility with respect to the amount and timing of wind generation that needs to be installed over this resource planning period. We are also concerned the PTC benefit will expire at the end of 2012 and not be renewed. As a result, our base case model does not add any incremental wind projects beyond 2012, pending a better understanding of the economics of the post-2012 wind market. For comparison purposes, we have also modeled a sensitivity in which we install 900 MW of wind between 2013 and 2020, based on our current estimates of post-2012 wind pricing assuming the PTC is not extended.

C. Sensitivity Analysis

To determine how changes in our assumptions impact the costs or characteristics of different plans, we examine our plans under a number of scenarios as described on page 4-9 of our initial Resource Plan. We used the same sensitivity scenarios as were included in the original filing, except as specifically described above.

Updated Table 4.2 shows the PVRRs of the proposed plan under the base assumptions and various sensitivity tests.

Updated Table 4.2
PVRRs of Proposed Plan and Sensitivities

	PVRR ($millions)	Difference from Base
Base Assumptions	$78,199	$0
High Gas + 20%	$79,436	$1,237
Low Gas -20%	$76,915	($1,283)
Low CO2 $9/ton 2012	$81,727	$3,529
Mid CO2 $17/ton 2012	$84,826	$6,627
High CO2 $34/ton 2012	$91,139	$12,940
Late CO2 3 Source Blend	$83,121	$4,922
High Load	$80,978	$2,779
Low Load	$75,096	($3,103)

Under the "low load" sensitivity, Strategist does not add new resources until 2025. Under the "high load" sensitivity, Strategist suggests that we would need to consider adding combined cycle generation instead of combustion turbine peaking units, and potentially bridge a 2017 resource need with short-term capacity or a combustion turbine. While we do not consider this scenario as likely, the additional generation selected by Strategist under this sensitivity highlights the value in having a specific, implementable contingency generation plan available to us to deal with changes in the forecast. Our proposed contingency plan is discussed later in this update.

Minnesota Statute § 216B.2422, subd.3, requires that we consider the environmental cost values for various emissions established by the Commission. Updated Table 4.3 shows how incorporation of those values affects the PVRR for the proposed Five Year Action Plan.

Updated Table 4.3
PVRRs of Plan w/ Commission Externalities

	PVRR ($millions)	Difference from Base
Base Assumptions	$78,199	$0
High Externalities	$80,064	$1,865
Low Externalities	$78,488	$290

D. Scenario Analysis

To address issues that have been raised since we filed our 2007 Resource Plan, we developed two additional set of scenarios – the "North Dakota/South Dakota" ("ND/SD") scenario and the No New Wind/Full Wind Scenario. The ND/SD scenario has been developed pursuant to settlements with North Dakota and South Dakota in our most recent general rate cases in those jurisdictions. The No New Wind/Full Wind scenarios have been developed based on our requirement pursuant to Minn. Stat. §216B.1691, subd. 2e, to update information on the rate impacts of complying with the RES.[7]

[7] *See* Docket No. E999/CI-11-852.

1. ND/SD Scenario

As with our initial Resource Plan, our ND/SD scenario was designed around the environmental and renewable policies in North Dakota and South Dakota. Both jurisdictions have similar policies, so we developed a single scenario designed to meet but not exceed federal, North Dakota, and South Dakota environmental and renewable requirements as they currently exist. In this update, we include the same set of assumptions and variations used in the initial Resource Plan, except that we included the impacts of Minnesota conservation and demand-side management in our base case.

In this update, the ND/SD scenario differs from our updated plan only in that we allow a supercritical pulverized coal facility ("SCPC") without sequestration to be selected in the ND/SD scenario, and not in the updated plan. We believe it would be difficult to permit such a facility, and as a result we do not consider it a viable option for our resource plan; however, one could potentially be added under North Dakota and South Dakota law. In our August 2010 filing, our modeling of the ND/SD scenario resulted in the selection of three SCPC coal plants in the expansion plan. In this update, the ND/SD scenario is identical to the base case. The change in resources between the August 2010 filing and this update results from a combination of higher capital costs for coal plants, lower capital costs for combined cycle and combustion turbine plants, lower gas prices and lower forecasted load in the current model.

Our updated analysis of the ND/SD Scenario shows that our proposed plan is a reasonable plan, even when we consider it in light of the different policy approaches that North and South Dakota use.

2. No New Wind/Full Wind Scenarios

Consistent with the requirements to consider the cost impacts of meeting the RES, as well as our own goals to maintain a cost-effective and diverse resource mix, we have modeled a scenario assuming full compliance with the RES in 2020 and beyond. Our model assumes that the PTC is not extended beyond 2012 and that wind prices start at current cost levels and escalate at approximately 2% per year. The full wind expansion plan includes the following resources through 2025:

Updated Table 4.8
Full Wind Scenario Expansion Plan

Year	Planned Additions	Combined Cycle	Combustion Turbine	Supercritical Pulverized Coal	Wind (Accredited)
		Generic Additions			
2011					
2012	Wind 32MW				
2013	Wind 32 MW				13 MW
2014					13 MW
2015	PI EPU 58 MW MH 375 MH 350				13 MW
2016	PI EPU 58				13 MW
2017					13 MW
2018			195 MW		13 MW
2019			195 MW		13 MW
2020					26 MW
2021	MH 125				13 MW
2022			195 MW		13 MW
2023					13 MW
2024			195 MW		13 MW
2025		729 MW	364 MW		13 MW

In comparison with the proposed plan, the Full Wind scenario adds one fewer combustion turbine, eliminating the one proposed for 2020. The Full Wind scenario also increases

Updated Table 4.9 compares the PVRRs of the Full Wind scenario with our proposed plan.

Updated Table 4.9
PVRR Differences Between Proposed Plan and
Full Wind Scenario

PVRR ($millions)	Base Case	30% RES	Difference
Base Assumptions	$78,199	$79,231	$1,032
High Gas + 20%	$79,436	$80,260	$825
Low Gas -20%	$76,915	$78,167	$1,252
Low CO2 $9/ton 2012	$81,727	$82,511	$784
Mid CO2 $17/ton 2012	$84,826	$85,406	$580
High CO2 $34/ton 2012	$91,139	$91,322	$183
Late CO2 3 Source Blend	$83,121	$83,721	$601
High Load	$80,978	$82,082	$1,105
Low Load	$75,096	$76,127	$1,031

These results indicate that under our current assumptions, the Full Wind scenario is more expensive than the proposed plan under base assumptions and all sensitivities. However, the assumptions surrounding these scenarios could change in the future. The PTC could be renewed, wind and solar prices could fall, the costs of other resources and fuels could rise, and many other factors can and will affect the cost of adding renewables to our system in the future. We propose to monitor the market for wind and other renewables after 2012 and add individual wind projects that prove to be cost effective for our customers. To the extent that we believe RES compliance will result in significant rate impact, we will explore our options, including the option to request an off ramp, at that time.

The emission differences between the two scenarios are presented in Table 4.10.

Table 4.10
Emissions Comparison
Tons Emitted, 2010-2049

	Updated Plan	Full Wind	Difference
SOx	977,710	933,762	(43,949)
NOx	757,893	724,508	(33,384)
CO2	915,924,364	865,138,900	(50,785,464)
CO	276,006	247,214	(28,792)
PM10	97,758	92,099	(5,659)
HG (lbs)	7,461	7,202	(259)

Emissions are lower in the Full Wind scenario, which could be a benefit for compliance with future environmental requirements. We would need to understand the costs of alternative means of compliance before suggesting that installing additional renewables is the better option. We will continue to evaluate both cost and emissions as we move forward to implement our renewable strategy.

E. Conclusion

Our updated plan combines reasonable cost and fuel diversity, and takes into consideration current and expected environmental regulation. As we discuss in subsequent sections, it provides considerable flexibility to adjust resource additions as more clarity emerges around the economy as well as key policy decisions. Implementation of this plan over the next several years will allow us to operate our system efficiently and meet our customers' needs at an overall reasonable cost. We will continue to monitor and analyze our resource needs and provide additional detail regarding our plans in our next Resource Plan filing.

IV. NUCLEAR GENERATION

A. Introduction

Our two nuclear power plants are essential parts of our generation portfolio. Monticello and Prairie Island together provide nearly 30 percent of our customers' electricity requirements. These low-cost, base load units operate at high capacity factors, around the clock, and without emissions associated with fossil fuels. The Commission previously authorized additional spent fuel storage, which will permit these plants to operate for another 20 years. We also successfully obtained license renewals from the NRC authorizing operation for another 20 years at both plants. In addition, the Commission previously approved a 71 MW capacity expansion at Monticello in January 2009 and a 164 MW capacity expansion at Prairie Island in December 2009.

The increases in plant generating capacity at Monticello and Prairie Island are an integral part of our generation program incorporated in our initial Five-Year Action Plan. This update reports on the status of our efforts to implement generating capacity increases at Monticello and Prairie Island. Our program of initial capital projects to refurbish and increase capacity is nearing completion at Monticello. During this process, we experienced complications in the NRC's licensing process that have delayed our ability to operate at higher production levels. In addition, during the process of detailed design, procurement, and installation of equipment, we have experienced higher costs than previously anticipated.

We are incorporating lessons learned from the Monticello project, our assessment of other utilities' experiences, and the NRC's reaction to Fukushima Daiichi, into our planning at Prairie Island. Because of our experience with the Monticello capacity expansion and other costs pressures, we believe it is appropriate for the Commission to consider our refreshed analysis and reaffirm before we proceed with additional investment for our capacity expansion program at Prairie Island. Based on our current analysis, completing the expansion program appears to remain cost-effective for our customers, but a separate Change in Circumstances proceeding would allow for additional review of these issues.

B. Monticello

Industry experience demonstrated that years of reactor safety technology improvements, plant performance feedback, and improved fuel and core designs can allow reactors such as Monticello to safely generate more power than originally licensed. Based on this experience, we proposed a program to increase capacity at Monticello by approximately 71 MW, to a total plant capacity of 656 MW. This capacity uprate program was approved by the Commission in January 2009 in Docket No. E002/CN-08-185.

To obtain greater capacity, the reactor will be operated at a higher thermal power level and changes are being made to systems at the plant to increase electrical output. The changes are not a discrete set of projects undertaken solely to increase generating capacity; rather, many of the systems, structures, and components involved are also being refurbished or replaced as part of our program to ensure the plant operates safely and reliably throughout its extended life.

Our overall program at Monticello was designed to be implemented in two phases, corresponding with two scheduled refueling outages in 2009 and 2011. During the 2009 refueling outage, detailed engineering was done to support NRC license review, equipment was designed, procurement commitments were made, and installation work was performed. As we approached the 2011 outage, adjustments were made to the implementation schedule. Work was rescheduled into two plant outages in 2011 in response to indications of slowing NRC regulatory review. The work scheduled for the normal plant refueling outage in spring 2011 was completed. However, after further analysis and discussions with NRC staff, the remaining portion of the installation work has now been deferred to the normally scheduled Spring 2013 refueling outage to minimize disruptions of plant operations.

The change in schedule is the result of a more involved and lengthier license amendment process before the NRC than anticipated. In light of the earthquake and tsunami that damaged the Fukushima Daiichi plant in Japan, the Advisory Committee on Reactor Safeguards, who advise the NRC Commissioners, has recommended that the impact of the Fukushima Daiichi accident be reviewed to assess possible impacts on the regulatory process and requirements for capacity increases at nuclear plants in the United States. Discussions with the NRC staff indicate that they will take additional time to understand the impacts of Fukushima Daiichi on power uprates at nuclear power plants like Monticello that utilize Mark-I containments. We now expect the licensing process to extend into 2013, and as a result, we have moved the remaining work needed to achieve the power uprate to the regularly-scheduled Spring 2013 refueling outage.

We anticipate the increased capacity will be available in 2013. The shift of the additional 71 MW of system capacity to 2013 does not have an impact on our Resource Plan. As discussed in our updated forecasting and resource needs assessment, we have adequate resources in the next few years even if completion of the Monticello capacity upgrade is delayed to 2013.

C. Prairie Island

The Commission approved our proposed capacity uprate program for Prairie Island, as well as additional on-site dry-cask storage to support operations for additional 20 years.[8] At that time, we estimated it was possible to expand capacity at Prairie Island by 164 MW (82 MW per unit) during refueling outages in 2014 and 2015.

[8] *See* Docket Nos. E002/CN-08-509 and E002/CN-08-510.

The Certificate of Need analysis, which is based on information gathered early in the development process before detailed engineering is completed, indicated capacity increases could provide $500 million in benefits to customers, as measured by the present value of system revenue requirements ("PVRR"). Based on additional engineering work to date, as well as other cost risks, we believe a Change in Circumstances proceeding would be appropriate as it will allow us to present and incorporate new information since obtaining the Certificate of Need.

In June 2010, we received the license renewals from the NRC allowing the plant to operate up to an additional 20 years. The NRC will not review amendments to increase output at the same time that a license renewal application is pending. Once license renewals were obtained, we proceeded with the supporting work for the license amendments needed for the EPU program. This work included more detailed engineering, preparing specifications for equipment, and issuing Requests for Proposals and receiving proposals from equipment vendors and installers. Additionally, after further discussion with bidders, performance guarantees for each proposal were received from bidders. Overall, we have spent just over $60 million to get to this stage in the process; however, we estimate at least another $20 million and potentially more will be required to complete the licensing process. Part of the remaining cost to prepare applications is in response to recent NRC guidance which emphasizes a fuller and more complete final design in applications, instead of being developed in parallel with the NRC staff's review. We also anticipate that an extended review process, 18-24 months long, is possible as the NRC considers the applicability of any lessons learned from Fukushima Daiichi.

Additionally, since our initial Resource Plan filing, both the achievable capacity and cost of the EPU program at Prairie Island have changed. As a result of the engineering to date and the performance guarantees received from vendors, capacity estimates have changed in two ways:

- *License Amendment*. In April 2010, the NRC authorized operating license amendments that allow us to rely on new feedwater flow monitoring equipment which more precisely measures plant conditions. This "measurement uncertainty recapture" effort allows us to utilize plant capacity that could not previously be used absent the enhanced precision in monitoring and increased plant capacity by 18 MW. We began operating at the higher capacity level in October 2010.

- *Low Pressure Turbines*. Our estimate of the potential capacity increase has been scaled back by approximately 29 MW. To achieve that last 29 MW increment, it now appears we would have to add improvements to the plant's low pressure turbine stages and make significant changes to condensers to reduce turbine backpressure which affects performance. Currently, our estimate of the cost of these additions could approach as much as $200 million, making the last 29 MW increment not justifiable.

After these two adjustments, we estimate 117 MW of capacity increases can be captured with the remaining EPU program.

We have also updated our analysis of the cost of the EPU program. To do this, we investigated the costs associated with a number of the major components of the program. Engineers also provided estimates of the net avoidable cost in the overall life extension and EPU capital program at the plant if chose not to proceed any further with the EPU effort. Our current estimate is that the total cost of the EPU program will be approximately $250 million, $187 million of which can be avoided if we were to terminate the program.

The updated Strategist simulation model continues to predict customer benefits will result from the completion of the remaining 117 MW of the EPU program. However, the magnitude of the remaining benefit has declined. The PVRR is predicted to be $113 million lower with completion of the EPU program compared to terminating now and adding generation at the appropriate time to meet system demand. This benefit is lower than what was found during the Certificate of Need proceeding. In addition, the analysis for this update filing did not account for the risk of cost increases that might occur during the completion of the engineering to support license applications, during the NRC review process before issue a license amendment, or as the result of unanticipated scope changes during installation. Additional review of these and other potential cost risks can be explored during a Change in Circumstances proceeding.

We did conduct limited sensitivity analysis to show why reevaluation is appropriate. Under one scenario, we increased the overall cost of the EPU program estimate by 50 percent. If the total cost of the EPU program was $375 million, approximately $310 million of which could be avoided, the modeling indicates the cost to be slightly greater than simulated benefits. The PVRR of completing the program is $40 million greater than terminating now. We also tested the impact of a delay in licensing like that experienced at Monticello. A delay of one more refueling cycle[9] changes modeling results by only $5-$10 million on a PVRR basis.

[9] Normal refueling outages are currently scheduled for both Units in 2016. Thus capacity upgrades would be available in 2016 and 2017 in this scenario.

We are currently examining the likelihood of cost increases associated with each major component of the Prairie Island EPU program. This will allow us to better assess where potential costs and benefits. We are also examining the experience of other nuclear plants like Prairie Island as they implemented EPU programs. Finally, we are assessing the similarities and differences in risk between EPU programs at Monticello, a boiling water reactor, and Prairie Island, a pressurized water reactor design. The results of this process will help inform the Change in Circumstances proceeding.

For these reasons, we believe it is appropriate to reassess the benefits of the Prairie Island EPU program. Such a review would occur before we undertake two expensive parts of the program: completing the licensing process and making equipment commitments. A Change in Circumstances proceeding would allow us to refresh this analysis using more detailed information gathered since the Certificate of Need proceeding. In addition, this formalized review by the Commission and input from all our stakeholders will help parties better assess the costs associated with proceeding with the Prairie Island EPU program. This will provide the opportunity to consider and reaffirm their interest in proceeding based on this new information.

D. Conclusion

We expect our Monticello increased capacity to be available in 2013. The shift of the additional 71 MW of system capacity to 2013 does not have an impact on our Resource Plan. Before continuing with the Prairie Island EPU program, we believe it is appropriate to reassess the benefits of the program. Although our current analysis indicates proceeding with the remainder of the program to achieve 117 MW of additional capacity is beneficial to customers, there may be additional, costs. We plan to complete our assessment and provide more detailed modeling results and analysis in a separate, comprehensive Change in Circumstances filing so that the Commission can consider the potential costs before we proceed with additional investment. We anticipate such a Change in Circumstance filing can be made before the end of the first quarter 2012.

V. BLACK DOG REPOWERING PROJECT

As a part of our initial Resource Plan, we identified repowering Black Dog Units 3 and 4 as one option to meet our customers' future energy needs. Forecasts developed for the initial filing indicated our system would require additional long-term capacity between 2015 and 2018. In addition, anticipated environmental regulations suggested the use of coal at our existing Black Dog Units 3 and 4 to no longer be feasible. Under these circumstances, we determined that retiring Black Dog's existing Units 3 and 4 (253 MW) and replacing them with an approximately 700 MW natural gas-fired combined-cycle facility by 2016 was the best available option at that time.

Developing this project has included engineering and other work necessary to bring the project online by 2016, including obtaining regulatory permits. To that extent, we filed an application for a certificate of need which can be found in Docket No. E002/CN-11-184. We committed to keep the Commission and stakeholders informed of any changes in the need or timing for the Black Dog Repowering Project because of the continuing poor economy.

Since economic growth in Minnesota as well as the country as a whole remained stalled, we updated the Black Dog CON proceeding with revised forecast information in June of 2011 ("Spring 2011 Forecast"). While discussed in detail in the Forecast section of this update, the Spring 2011 Forecast indicated customer needs had softened but, overall, still supported pursuing the Black Dog Repowering Project because a 2016 capacity deficit of 320 MW was still being projected if Black Dog Units 3 and 4 were retired. The Spring 2011 forecast could have supported a delay in to 2017 or 2018; however, a 2016 schedule remained prudent as it preserved flexibility for meeting our customers' needs should the economy recover faster than anticipated. We recognized that further declines in our forecasts could impact our need for the Black Dog Repowering Project in 2016.

As described in this update, our customers' needs are not materializing in a manner as we originally believed because the economy continues to grow slowly. Under current forecasted conditions, we no longer see a capacity deficit in 2016. Rather, our current analysis suggests we will not need additional long-term capacity resources until at least 2018.

In light of the revised forecasts provided in this update, we re-ran our modeling for the Black Dog Repowering Project. Our current analysis supports adding one or more combustion turbine peaking units rather than the large combined cycle unit proposed in the Black Dog Repowering Project to fulfill our projected 2018 capacity needs. For example, a model comparing a base case, which adds generic combustion turbines in 2018, 2019 and 2020 but does not include the Black Dog Repowering Project, against scenarios where the Black Dog Repowering Project is placed in-service in 2016, 2017, 2018, and 2019 found the base case to be consistently more cost-effective.

Black Dog Scenarios: PVRR Differences

	PVRR ($millions)	Difference from Base
Base Case	$78,199	$0
Black Dog 2016	$78,216	$17
Black Dog 2017	$78,207	$9
Black Dog 2018	$78,193	-$6
Black Dog 2019	$78,215	$17

Since the Black Dog Repowering Project proved to be marginally more cost-effective in 2018, we performed additional analysis. This is typical when scenarios are this close since small changes in assumptions can change the outcome for the entire modeling period.

We analyzed PVRR savings broken down by 10-year periods for the next 40-years. Examining the PVRRs by periods allows us to identify when the savings of one option over another are occurring within the 40 year modeling period. The base case and combustion cycle assumptions remained the same. Our results are as follows:

PVRR Differences by 10-year Period

PVRR Deltas – ($millions)	**Total**	**2011-2020**	**2021-2030**	**2031-2040**	**2041-2050**
Base Case	$0	$0	$0	$0	$0
Black Dog 2016	$17	$200	-$16	-$83	-$85
Black Dog 2017	$9	$154	$8	-$74	-$79
Black Dog 2018	-$6	$104	$31	-$68	-$73
Black Dog 2019	$17	$81	$81	-$67	-$79

In general, this analysis concludes that adding combustion turbines is more cost-effective than the Black Dog Repowering Project in the first 10-20 years. In the 2018 scenario, for example, in years 2011-2030, the PVRR of the Base Case is $135 million lower than the Black Dog CC case. In years 2031-2050, the Black Dog CC case saves $141 million over the Base Case. While these two periods net out to a PVRR difference of about $6 million, all of the savings for the CC over the base case occur in the last half of the modeling period. In the early years, the Optimized Plan is a better value for our customers.

We also performed sensitivities on these scenarios. The PVRR Differences of the sensitivities are as follows:

PVRR Deltas- $millions	**Base Case**	**BD CC 2016**	**BD CC 2017**	**BD CC 2018**	**BD CC 2019**
Base	$0	$17	$9	($6)	$17
High Gas	$0	($16)	($23)	($36)	($10)
Low Gas	$0	$59	$48	$32	$53
Low CO2	$0	($19)	($26)	($40)	($17)
Mid CO2	$0	($53)	($59)	($72)	($48)
High CO2	$0	($161)	($158)	($164)	($133)
Late CO2	$0	($59)	($68)	($82)	($60)
High Load	$0	($60)	($61)	($70)	($5)
Low Load	$0	$273	$253	$227	$197

We note the models above do not conclusively support adding combustion turbines as the Black Dog Repowering Project provides value in later years. Again, considering the PVRR savings broken down into 10-year periods, the Black Dog Repowering Project has much higher costs than the Base Case over the first 20 years.

2018 Black Dog CC Sensitivities
PVRRs by 10-year Periods

PVRR Deltas- $millions	**Total**	**2011-2020**	**2021-2030**	**2031-2040**	**2041-2050**
Base BDCC 2018	($6)	$104	$31	($68)	($73)
High Gas	($36)	$100	$21	($79)	($78)
Low Gas	$32	$109	$46	($57)	($67)
Low CO2	($40)	$101	$18	($79)	($81)
Mid CO2	($72)	$99	$7	($89)	($88)
High CO2	($164)	$80	($25)	($113)	($106)
Late CO2	($82)	$103	$8	($97)	($96)
High Load	($70)	$37	($12)	($44)	($51)
Low Load	$227	$186	$199	($63)	($95)

The models which ultimately support the Black Dog Repowering Project do so in out-years. We do not believe out-year modeling is as reliable because long-term assumptions are subject to greater uncertainty. The short-term and long-term price of natural gas, and future environmental regulations are exemplary.

We believe this modeling work is informative with respect to the likely timing and type of our resource need; however, current forecasts confirm that we do not need an additional resource in 2016 or 2017. To the extent we have a need beyond that horizon, our analysis indicates the addition of combustion turbines, or continued operation of Black Dog Units 3 and 4 with natural gas and supplemented with short-term capacity contracts are more cost-effective than the Black Dog Repowering Project. We appreciate, however, that this information is imperfect. Therefore, we believe it is in our customers' best interest to withdraw our application for a Certificate of Need and companion Site/Route permit for the Black Dog Repowering Project.[10] This will allow us the opportunity to obtain more information and perform additional analysis. Part of this assessment will include examining whether we can continue operating the existing Black Dog Units 3 and 4 on natural gas after coal operations cease in 2014 due to anticipated environmental regulations as well as the age of the units. It may be that continuing to operate these units on natural gas will provide us with peaking resources that will influence the timing of later resource decisions. Such an option may be a cost-effective way to bridge our needs until the next long-term capacity addition is required and could provide us with additional flexibility in the timing and configuration of future proposed resource additions.

Our work to date on the Black Dog Repowering Project has provided our customers with considerable value and has been reasonable under the circumstances. When we first began, all signs indicated a resource would be needed by 2016. Given the time needed to bring a substantial project like this to fruition, we moved forward, while always monitoring the situation to incorporate new information. These actions were prudent. Furthermore, by establishing a viable and cost-effective option to meet future capacity needs, most of the work already undertaken will be available for future use when it becomes clear future capacity is needed. Because the Commission does not make decisions regarding cost recovery in Resource Plan proceedings, we will propose appropriate ratemaking treatment for these prudent costs in a separate filing.

In the end, the Black Dog Repowering Project may prove to be the best alternative for meeting our customers' medium-to long-term needs. It is also possible that other generation alternatives will prove to be better options. Given the continued volatility in our customers' future needs, we propose to continue monitoring the situation and thoroughly address the 2016 to 2018 planning horizon in our next Resource Plan cycle.

VI. SHERCO UNIT 3

As part of this filing, the Company provides this informational update about a recent occurrence at the Sherco Generating Station. As part of our approved action plan, in recent years, we have added generating capacity and improved production efficiency at the 800 MW Sherco Generating Station Unit 3, which is jointly owned by NSP (59%) and SMMPA (41%). In September 2011 we began a scheduled maintenance

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[10] *See* Docket No. E002/CN-11-184 and Docket No. E002/GS-11-307, respectively.

overhaul that included some of the work necessary to implement several of these upgrades. On November 19, 2011, Sherco Unit 3 experienced a significant failure during turbine testing while returning to service following the scheduled maintenance overhaul. The failure at Sherco Unit 3 resulted in fires in both the turbine and generator, and caused major damage to the unit, including the generator exciter and some turbine components. No physical injuries occurred as a result of the equipment failure; minor smoke inhalation injuries occurred due to the resulting fire. Units 1 and 2 at the Sherco Generating Station were unaffected and are operating normally.

An investigation into the cause of the equipment failure is under way. At this time we do not believe this incident will cause us to revise our Five Year Action Plan in the Resource Plan. However, we will reassess possible impacts to the Resource Plan after we conclude our investigation. While initial assessments indicate significant damage, repair scope and a projected return to service date for Sherco Unit 3 will not be known until the unit is disassembled and the extent of damage is fully known. We will keep the Commission and stakeholders informed as we investigate the cause and implications of this incident. We plan to open a new docket for future reports so that any updates related to this incident can be reviewed in a separate proceeding.

VII. ENVIRONMENTAL REGULATORY LANDSCAPE

A. Introduction

The Environmental Protection Agency ("EPA") has issued or is expected to issue several environmental regulations that impact our system within the Five-Year Action Plan period. In our initial Resource Plan filing, we provided an analysis of several pertinent EPA regulations and explained how they interact with our resource planning efforts. This update builds upon our original analysis, discussing how recent developments influence the Five-Year Action Plan. From an environmental perspective, our Five-Year Action Plan is characterized by:

- *Black Dog Units 3 and 4 Natural Gas Conversion.* Due to compliance costs and the units' age, we have concluded it is in our customers' best interest to discontinue using coal at Black Dog Units 3 and 4, shifting these units to natural gas in 2014. We also anticipated retiring these units completely once the Black Dog Repowering Project was placed in service. We now are investigating how long we may be able to continue to operate Units 3 and 4 on natural gas as an option to ensure adequate capacity on our system until the next generating addition is added.

- *Continued Evaluation of Sherco 1&2.* We continue to evaluate potential options for these units as they approach the end of their initial depreciation schedule in 2023. The EPA's pending review of the Minnesota Pollution Control Agency's ("MPCA") determination of the appropriate Regional Haze emission controls for these units might substantially impact this analysis.

- *Protecting Early Action Benefits of MERP.* By voluntarily and proactively addressing emissions at some of our oldest facilities as part of the Metropolitan Emissions Reduction Project ("MERP"), our system is well positioned to address pending and future EPA regulations, provided these early actions are given their full credit. We have challenged EPA's failure to recognize the benefits of MERP in their implementation of the Cross-State Air Pollution Rule ("CSAPR"). Regardless, our diverse resource mix allows us to comply with CSAPR requirements as currently proposed without major investments faced elsewhere in the country.

The remainder of this section explains how the following EPA regulations may impact the Company's system over the Five-Year Action Plan period:

- the proposed Mercury and Air Toxics Standards for Power Plants (otherwise known as the "Utility MACT" or "EGU MACT" rule);
- the CSAPR;
- the Regional Haze State Implementation Plan that MPCA has submitted to EPA for approval; and
- the proposed Clean Water Act, Section 316(b) Rule regarding Fish Protection at Cooling Water Intakes for Existing Steam Electric Plants.

B. Mercury and Air Toxics Standards

On March 16, 2011, the EPA proposed Mercury and Air Toxics Standards for power plants, which would replace the court-vacated Clean Air Mercury Rule. The proposed rule would require installation of Maximum Achievable Control Technology ("MACT"), as well as implementation of other emissions reduction strategies, to limit emissions of mercury, acid gases, and other hazardous air pollutants from power plants. We expect the proposed rule to be finalized in December of 2011 and compliance required within three years of final adoption. The discussion below is based on our assessment of the likely impact of the proposed rule, as it is not yet final. Our analysis could change, however, should the EPA modify the proposed rule in response to public comment.

According to our analysis, five units at three of our electric generating facilities would be impacted by the Utility MACT rule. These facilities are:

- Black Dog Units 3 and 4;
- Sherco Units 1 and 2; and
- Bay Front Unit 5.

The Utility MACT rule, as drafted, would apply to two other units on our system, unit 1 at the Allen S. King Generating Plant and unit 3 at Sherco, but it does not appear that additional controls are required for compliance at either unit.[11]

In addition, a related EPA rule – known as the Industrial Boiler ("IB") MACT – may impact two other units at our Bay Front Generating Plant. The IB MACT has been stayed, pending EPA's upcoming reconsideration of multiple aspects of the final rule. The discussion below is based on our assessment of the likely impact of the IB MACT rule as currently written, but our analysis could change depending on EPA's final determination as to the rule requirements.

1. Black Dog Units 3 and 4

Constructed in 1955 and 1960, respectively, Black Dog Units 3 and 4 are both coal fired units. We evaluated the costs of retrofitting these units to comply with the Utility MACT rule and other pending EPA regulations such as CSAPR. Based on our analysis, including an assessment of the compliance costs and the units' age, we concluded it would not be in our customers' best interests to continue operating these units using coal. Instead, we developed plans to switch these two units to natural gas-only operations prior to the EGU MACT compliance deadline, which we currently anticipate to be on or about January 1, 2015. We expect to ultimately retire these units and replace them with new natural gas generation but, as described in this update, decisions about the size and timing of that replacement generation are still pending.

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[11] King Unit I was constructed in 1968 and recently rehabilitated as part of MERP in 2007. King Unit 1 is a coal-fired unit that is subject to the Utility MACT rule and other pending EPA regulations. MERP has well positioned King Unit 1 for complying with these regulations and no further action is anticipated at this time. Sherco Unit 3 was constructed in 1988 and is a coal-fired unit that is subject to the Utility MACT rule and other pending EPA regulations. Sherco Unit 3 is equipped with control technologies that leave it well equipped for complying with these regulations and no further action is anticipated at this time. In addition, both King Unit 1 and Sherco 3 have installed control technology for mercury as required by the Minnesota mercury emission reduction statute.

2. *Sherco Units 1 and 2*

Units 1 and 2, totaling a summer-rated capacity of 1,379 MW of coal-fired generation, are located in Becker, Minnesota, and were constructed in mid-1970. We believe Utility MACT compliance will require two projects at these units:

- *Activated Carbon Injection Project*: To control mercury emissions, we expect to add activated carbon injection at these two units. We estimate this project will cost $12 million over a three-year period (2012–2014). This project is also part of our Minnesota Mercury Emissions Reduction Act of 2006 compliance program.[12]

- *Wet Electrostatic Precipitator Project*: We expect that we will need to replace and upgrade components of the wet electrostatic precipitators on these units to further reduce fine particulate emissions. We estimate this project would cost $10.5 million over a five-year period (2012–2016).

3. *Bay Front Units 1, 2 and 5*

These three units, totaling 76 MW of generation capacity, are located at our Bay Front Generating Facility in Ashland, Wisconsin, and were constructed between 1948 and 1956. These units used a combination of coal, waste wood, railroad ties, tire-derived fuel, natural gas, and petroleum coke as a fuel source. The proposed Utility MACT rule applies only to Unit 5 and, as with Black Dog Units 3 and 4, we conclude it would be cost prohibitive to perform the upgrades necessary to allow for continued operation on coal. We plan to comply with the proposed Utility MACT rule by switching Unit 5 from coal to natural gas-only firing on or about January 1, 2015. We also anticipate needing to install fabric filter baghouses on Units 1 and 2 (approximately $13 million in 2013–2014) to comply with the IB MACT and the Wisconsin State Mercury rule. Depending on baghouse effectiveness in removing mercury (determined by post-project testing), it may also be necessary to add an activated carbon injection system to Units 1 and 2 (approximately $1 million) in 2014 or 2015.

C. The Cross-State Air Pollution Rule

On August 8, 2011, the EPA finalized the CSAPR which is designed to facilitate compliance with Ozone and Particulate Matter 2.5 National Ambient Air Quality

[12] The Company's plan was approved by the Commission on November 4, 2010 (Docket No. E002/M-09-1456).

Standards in areas of the Eastern U.S. that the EPA found to be impacted by interstate transport of emissions from upwind states. The rule requires reductions in sulfur dioxide ("SO_2") and nitrogen oxide ("NOx") emissions from power plants in 28 Midwestern and Eastern states, including Minnesota and Wisconsin. CSAPR compliance obligations begin January 1, 2012. Minnesota is subject to annual NOx and SO_2 emissions limits, while Wisconsin is subject to both annual NOx and SO_2 limitations and to summer ozone season NOx limitations.

The CSAPR rule creates a "budget" of allowed emissions for each state. The allowance budget is then allocated to individual power plant units based on a formula utilizing the unit's historical heat input and emissions. Although emission allowances are allocated on a unit basis, utilities can aggregate their allowances to comply on a system basis. A utility can therefore comply with CSAPR by reducing emissions, purchasing allowances in markets that the EPA has established for that purpose, or through a combination of both.

Based on the initial CSAPR allocations, we may have small shortfalls in SO_2 and NOx emission allowances for 2012 and 2013 depending on demand conditions in those years. To make up for these shortfalls and thus comply with the rule, we would either have to reduce emissions or purchase additional emission allowances. Our review of EPA's CSAPR allocation methodology, however, revealed that it failed to provide sufficient credit for the early actions we took as part of the MERP to repower our High Bridge and Riverside generation facilities from coal to natural gas. These repowering projects reduced those facilities' NOx and SO_2 emissions by more than 95%, but EPA failed to credit us for our actions, contrary to its stated goals.

In order to ensure that our customers receive the full value of those early actions – actions for which they are already paying – and to guard against additional future CSAPR compliance costs, we have petitioned the EPA to reconsider its allocation methodology. We also sued the EPA in the United States Court of Appeals for the District of Columbia over its allocation methodology. We have taken these actions both to fix the current methodology of the CSAPR rule, and to guard against this CSAPR methodology establishing a precedent against early action credit in future EPA regulatory decisions.

Regardless of the outcome of our challenges to the EPA's actions, we may need to rely on some combination of operational changes and allowance purchases to comply with CSAPR. At this time, we do not anticipate that major new capital projects are necessary to comply. We continue, however, to evaluate opportunities for prudent and cost effective projects that would offer greater operating flexibility while preserving compliance margins.

D. Regional Haze

The EPA established the Regional Haze Rule in 1999. The rule is designed to improve visibility in 156 national parks and wilderness areas, collectively called "Class I" areas. Under the rule, states are required to develop and implement air quality protection plans to reduce emissions that cause or contribute to visibility impairment. States are required to regulate certain existing emission sources known as Best Available Retrofit Technology ("BART")-eligible sources. BART-eligible sources are large sources, including power plants, placed in service between 1962 and 1977 that have potential emissions greater than 250 tons per year. Sherco Units 1 and 2 are classified as "BART-eligible units," and MPCA required Xcel Energy to submit a BART analysis in 2006.

After years of analysis and review, the MPCA determined in 2009 that BART for units 1 & 2 were:

- *NOx*: Installation of low NOx burners, overfire air and other combustion controls, and
- *SO_2*: Installation of Sparger tubes as a retrofit to the existing wet scrubbers to improve SO_2 removal efficiency.

The Company has installed the required NOx controls at both units and plans to install the Sparger tubes for additional SO_2 removal between 2012 and 2014. These projects contribute to significant improvements to visibility at impacted Class I areas at a cost of less than $30 million to our ratepayers. While required because of Regional Haze program rules, these controls also assist the Company in complying with CSAPR, because they limit NOx emissions, and with Utility MACT, because improved SO_2 control also reduces acid gas emissions.

In October 2009, the U.S. Department of Interior certified to the EPA that visibility impairments at Class I areas are reasonably attributable to emissions from Sherco Units 1 and 2. This means Sherco Units 1 and 2 might also be subject to BART requirements under a separate part of the Federal Clean Air Act known as the Reasonably Attributable Visibility Impairment rule ("RAVI"), a precursor to the Regional Haze rule. The definition of BART is the same for both parts of the visibility program.

EPA is currently reviewing the MPCA's Regional Haze State Implementation Plan, which MPCA submitted in late 2009. Specifically, EPA and MPCA have been in discussions on what constitutes BART for Sherco Units 1 and 2. In its June 2011 preliminary review of the MPCA's BART assessment, EPA Region 5 indicated that it believes BART for Units 1 and 2 should include "Selective Catalytic Reduction" ("SCRs").

EPA's position that SCRs would be cost effective is based on inaccurate and unrealistically low generic project cost assumptions. Plant-specific estimates for Sherco Units 1 and 2 demonstrate that SCRs would cost customers upwards of $250 million. The MPCA considered SCRs as part of its BART review for Units 1 and 2 and determined that SCRs would not be cost-effective. Furthermore, the MPCA also found SCRs would not deliver significantly greater visibility improvement than the technology selected under MPCA's BART determination.

If the EPA ultimately requires the installation of SCRs, those controls may need to be in place as early as the 2017-2019 timeframe, depending on the timing of the EPA's decision and any resulting regulatory process.

Finally, the EPA is considering whether to allow states to substitute compliance with CSAPR for unit-by-unit BART requirements under the Regional Haze Program. If allowed, MPCA would have the option to displace unit specific BART requirements with system CSAPR compliance. Should this occur, no additional installations may be necessary at Sherco 1 and 2 to comply with the Regional Haze Program.

We committed in the Resource Plan to conduct a comprehensive analysis of the investments necessary to operate these units into the future and to compare the costs and benefits of continued operations against a number of alternatives. We propose to report our results in the next resource plan, and will include in our analysis the potential for significant investment for SCRs in 2017-2019.

E. Clean Water Act Section 316(b) Proposed Rule

On March 28, 2011, the EPA proposed new rules for cooling water intake structures at existing facilities. The proposed rule would apply to all existing utility generating plants that withdraw greater than 2 million gallons per day. Under the rule, utilities would need to retrofit intake structures to reduce the impingement of fish on intake screens by 88% or more on an annual basis. The proposed rule would also require the MPCA to set limits, on a case-by-case basis, that minimize the amount of aquatic organisms passing through intake screens (entrainment) for each site. The EPA's proposal would require compliance as soon as possible, but no later than 8 years following promulgation of the new rules. The proposal contains an exception for nuclear plants, which are given up to 15 years to comply if an NRC safety analysis is required. The EPA is expected to issue a final rule on July 27, 2012.

The EPA proposal is expected to mandate minimal technical performance standards and identify Best Technology Available ("BTA") for compliance. The proposed rules recommended performance standards that are approximately the same as what could be reasonably achieved with conversion to closed-cycle cooling; the proposed rule, however, did not mandate closed-cycle cooling.

We have been evaluating the proposed rule and believe it could have an impact on a significant number of our facilities, if it remains substantially unchanged. Changes to Section 316(b) requirements may have the effect of establishing cooling tower requirements at Black Dog in order to continue to operate Units 3 and 4 beyond 2015. We will provide further updates when the rule becomes final and its requirements clearer.

VIII. RENEWABLE GENERATION

A. Introduction

In Chapter 5 of our initial Resource Plan, we provided a significant amount of information about the amount and type of renewable energy we have on our system, as well as an analysis of our plans for adding renewable energy over the course of the resource planning period. In this section, we update that information and our plan to move forward in light of the evolving circumstances described in the Executive Summary.

Our five state system is geographically located such that we have access to some of the best wind resources in the world and access to cost-effective, reliable Canadian hydro resources directly to our north. Our renewable energy portfolio provides multiple benefits to our customers, as an intrinsic part of our commitment to maintaining a diverse, robust, reliable, clean, and affordable energy supply portfolio.

We have been aggressive in taking advantage of recent low prices for renewable energy resources, in particular competitively-priced wind and hydro generation. In August 2010, the Commission approved our most recent set of long-term capacity and energy purchases from Manitoba Hydro, effectively extending our long-standing purchases of significant hydroelectric power into 2025. This ensures that our customers will continue to take advantage of reasonably-priced and substantially carbon free generation throughout this planning period.

Further, we have been aggressive in the wind power market and have been able to take advantage of market pressures on behalf of our customers. Our recent experience shows we are well positioned to capture competitively priced renewable resources and to take advantage of the availability of the federal PTC which is set to expire at the end of 2012.

We are well ahead of the renewable energy targets established in the jurisdictions we serve. As a result, we have substantial flexibility and can adjust the timing of renewable energy additions to our system to ensure the best possible value for our customers. If wind power prices go up significantly (as is likely if the PTC expires and is not renewed), we can afford to wait for market forces to stabilize before going forward. In light of the anticipated expiration of the PTC at the end of 2012, we intend to allow the wind generation market time to adapt to the post-PTC environment before adding additional renewable generation on our system.

B. Wind Update

In 2010 and 2011, we saw significant downward price pressure in the cost of wind projects. Wind developers significantly reduced the price of proposals, in part due to lower project development and equipment costs, but also in response to the expected expiration of the PTC. The PTC reduces the cost of wind generation and its absence will create upward price pressure. After 2012, it is unclear what the cost of wind generation may be as the market adapts to the possible post-PTC environment.

To take advantage of the opportunity to procure low-cost wind generation within a short timeframe, we have increased our wind generation portfolio in advance of the PTC expiration. Since we filed the initial Resource Plan, we have added about 330 MW of wind, for a total of about 1,600 MW of wind generation currently on our system. As discussed below, we will add at least 200 MW in 2012 with the potential for an additional up to 300 MW prior to the PTC expiration, depending upon the outcome of ongoing discussions. Deploying all of these resources prior to the PTC expiration would, if successful, provide value to customers and put us substantially ahead of all of our renewable energy targets.

- *Prairie Rose Wind Farm.* In the Resource Plan, we indicated our intention to issue an RFP for up to 250 MW of wind energy, to be in service by the end of 2012. We issued the RFP on September 15, 2010, and received a broad response with favorable pricing compared to the current market for electricity. On June 30, 2011, we requested Commission approval for a power purchase agreement with Geronimo Wind Energy for the 200 MW Prairie Rose Wind Farm in Rock and Pipestone counties in Minnesota. The contract also includes an option for the Company to purchase the development rights for another 100 MW project adjacent to the Prairie Rose site. On November 10, 2011, the

Commission approved the power purchase agreement for the Prairie Rose Wind Farm.[13]

- *Nobles.* At the end of 2010, we placed into operation our second Company-owned wind farm, the 200 MW Nobles Wind Project in Nobles County, Minnesota.

- *Merricourt.* On April 1, 2011, we notified enXco that we were terminating our arrangement with them for the 150 MW Merricourt Wind Project in McIntosh and Dickey counties in North Dakota.

- *Other Wind Opportunities.* We are exploring other opportunities to add cost-effective wind generation prior to PTC expiration at the end of 2012. We may be able to obtain up to an additional 300 MW of wind generation on our system. Because these projects have not been finalized and we have not yet obtained necessary regulatory approvals, we have not included them in our base case analysis.

- *Small Wind Projects.* Since filing the Resource Plan, we have brought seven smaller wind projects on-line, totaling about 125 MW. Those projects are:
    - Ridgewind Wind Farm, 25 MW
    - Grant Wind Farm, 20 MW
    - Winona, 1.5 MW
    - Community Wind North, 30 MW
    - Valley View, 10 MW
    - Danielson Wind Project, 19.8 MW
    - Adams Wind Project, 19.8 MW

  We now have over 350 MW of small and community-based wind projects on our system, and over 100 MW pending construction in 2012.

C. Solar Update

At the time we filed our Resource Plan, we had just over 1 MW of solar generation on our system. By the end of 2011, we may have up to 4.2 MW of solar capacity on our system. Close to 3 MW of this amount is capacity added under our Solar*Rewards program, which is an energy conservation program available to residential and commercial customers. Since the launch of this program nearly two years ago, customers' interest in installing solar on their homes and businesses has been strong

[13] *See* Docket No. E002/M-11-713.

enough to allow the program to reach its statutory spending limit for 2011, and be on track to reach it again in 2012. Over 30 percent of the capacity installed under this program is from panels manufactured in Minnesota.

D. Future Renewable Needs

With our planned wind energy additions, we will have sufficient renewable generation by the end of 2012 to utilize banked RECs for several years. With the addition of the Prairie Rose 200 MW Project and the small, community-based projects described above, we expect to have RECs sufficient to satisfy our RES requirements through approximately 2020. If the additional wind generation discussed above is added to our system prior to the end of 2012, we could have adequate RECs available to meet our requirements through around 2023.

Installed generation and banked RECs allows us flexibility to time our additions of renewable energy to take advantage of favorable market conditions. This flexibility is important under current circumstances as we anticipate the expiration of the PTC and expected upward price pressure for wind generation. As a result, we believe it is appropriate to modify our Five-Year Action Plan. Previously, we proposed to add approximately 100 MW of wind generation per year through 2020. We believe it is now appropriate to reassess our wind generation procurement efforts until after 2012 to allow the potential post-PTC market to develop. We will continue to monitor market developments and will consider advantageously-priced options if they are presented to us. We will provide the Commission updates on this strategy in our periodic renewable energy compliance reports and will review this strategy in our next resource plan filing.

The table below demonstrates our compliance with the renewable targets for the states in which NSP operates, in aggregate, for years 2012, 2016, and 2020, assuming that we add no additional wind capacity beyond the projects we currently have under contract.

Compliance with Renewable Targets, without Additional Wind

	2012	2016	2020
1. NSP Retail Sales	42,073,254	43,302,825	44,301,828
2. Banked RECs at Beginning of Year	9,491,229	15,111,531	9,328,149
3. RECs Generated During Year	7,277,389	8,085,668	7,553,139
4. RECs Generated During Year as a % of NSP Retail Sales	17.3%	18.7%	17.0%
5. RECs Needed for Compliance (all jurisdictions)	6,210,538	9,304,232	11,123,896
6. Banked RECs After Full Compliance (2+3-5)	10,558,080	13,892,968	5,757,392

As shown, by using installed generation and our banked RECs, we will be able to comply with all of the renewable targets through 2020, without any additional wind beyond our current contracted projects.

We also have the possibility of adding 150-300 MW of wind by the end of 2012. The table below shows our banked RECs after full compliance for those cases:

End-of-year REC Balances with 150 and 300 MW Additional Wind

End of year RECs	2012	2016	2020
+150	10,558,080	16,049,404	10,070,264
+300	10,558,080	18,205,840	14,383,136

In order to remain in compliance with our renewable requirements in each state, we will need to add wind at some point in the latter years of the planning period. Consistent with our proposal to add wind resources when it is cost-effective to do so, to the extent that we cannot, we will further evaluate our options, including the potential to petition the Commission for a modification or delay of our renewable energy standard pursuant to Minn. Stat. §216B.1691, subd. 2b.

E. Rate Impacts of the Minnesota Renewable Energy Standard

In the 2011 legislative session, the Minnesota Legislature enacted Minnesota Statutes, section 216B.1691, subdivision 2(e), which requires utilities subject to the RES to:

> …submit to the commission and the legislative committees with primary jurisdiction over energy policy a report containing an estimation

> of the rate impact of activities of the electric utility necessary to comply with [the Minnesota Renewable Energy Standard]. The rate impact estimate must be for wholesale rates and, if the electric utility makes retail sales, the estimate shall also be for the impact on the electric utility's retail rates. Those activities include, without limitation, energy purchases, generation facility acquisition and construction, and transmission improvements.

On October 25, 2011, we filed our initial report under that section, and summarized our analysis as follows:

- During the 2008/2009 time frame, energy prices were about 0.7% lower with the wind resources that were part of our system than prices would have been without them. During this same period, biomass resources were slightly more expensive but still not significantly higher than non-renewable energy.

- We project that customers will pay approximately 1.4% more for energy over the next 15 years as the result of complying with the RES. Two key assumptions drive this result: 1) the PTC expires in 2013, and 2) the currently forecasted cost of natural gas for generation remains low. If the PTC is extended through 2025, rate impact of renewable energy is reduced to 0.7%.

- While the results show renewable energy to be slightly more expensive over the planning period, the differences do not appear significant. Changes in comparative factors, such as the cost of fuel, could result in renewable energy being less expensive than non-renewable alternatives.[14]

F. Conclusion

We estimate that the cost of meeting the Minnesota renewable requirements will be slightly higher than that of a plan that does not include additional generation. The actual cost to meet our renewable obligations will depend on a number of variables at the time we make decisions on incremental renewable additions: the cost of wind generation, the cost of natural gas generation and fuel, the growth rate for energy consumption and demand on our system and the existence of any other incentives or costs. For this reason, we plan to continue to analyze our renewable additions on a project-by-project basis, and will seek approval for each project as we propose to implement it. We will use our banked RECs as needed to reduce compliance costs, and will petition the Commission for modifications of the Minnesota Renewable

[14] *See* Xcel Energy Rate Impact Report (October 25, 2011) at p. 1 in Docket No. E999/CI-11-852.

Energy Standard if we believe that new renewable additions will have a significant rate impact on our customers.

IX. DEMAND-SIDE MANAGEMENT

The Company continues to strive to achieve the 1.5% savings goal established in the Next Generation Energy Act of 2007 ("Act"). We had a successful year in 2010 – achieving over 415 GWh of electric savings, or 1.35% of sales, which exceeded our goals. We believe this level of performance was possible because of the factors discussed in the initial Resource Plan. Our strategies built momentum and drove unprecedented levels of program participation. For 2011, we expect to exceed the 1.5% savings goal through a combination of traditional Conservation Improvement Programs ("CIP") and electric utility infrastructure improvements.

We are happy with these accomplishments and are committed to continuing this success. While we expect to perform at a similar level in 2012, we foresee challenges in sustaining this performance beyond 2012. More aggressive residential and commercial lighting standards, building codes and equipment standards will be phased in. Additionally, as we reach higher and higher levels of market penetration, the available market potential, absent any significant advances in energy efficient technologies, shrinks. Further, future savings could be affected if large commercial and industrial customers' requests to be exempted from CIP are approved.

To help address some of the challenges, we have actively participated in stakeholder workgroups formed to tackle issues surrounding these concerns. While these workgroups have made significant progress in many areas, work still remains to develop defensible methodologies for counting savings from behavioral programs and codes and standards changes.

Given these challenges, we continue to believe that our proposed goal working toward the 1.5% savings goal over the next several years is an aggressive goal that will require us to innovate and further strengthen our commitment to DSM.

X. CONTINGENCY PLANNING

The modifications to our Five-Year Action Plan described in this filing are driven largely by our updated forecast of customers' future energy needs. Forecasts are by their nature estimated predictions of future events based on a specific set of assumptions; actual results will differ from the forecast depending upon whether those assumptions prove accurate. Our obligation, however, is to ensure sufficient capacity is available to serve our customers, regardless of whether actual demand is higher or lower than forecast.

We are comfortable that the proposed changes to our Five-Year Action Plan will allow us to meet our customers' future needs. However, we continue to believe having options to address unanticipated changes is important as solutions can be time-consuming such that the timing of the resource is inconsistent with the need. A workable contingency plan, consisting of one or more facilities that are ready to execute when needed, would allow us to cost-effectively meet customers' needs should unanticipated changes, such as a robust economic recovery, materialize.

We believe a contingency plan would include numerous activities to prepare for rapid resource deployment. We could identify a site, request interconnection, complete engineering, and reserve equipment. In addition, we could potentially permit a facility in advance. All of these things would allow us to move swiftly in the event of an unexpected need. However, these activities are typically not pursued prior to a decision to move forward with a project. Some activities are even restricted by existing laws pertaining to certificates of need and the Commission's bidding requirements. These practical impediments, as well as the significant expense that must be incurred to develop a long-term capacity project, create disincentives to engage in advance contingency planning of this type.

Our experience with developing generation projects and making long-term capacity purchases suggests some mechanism for allowing prudent advance expenditures as part of a contingency plan is appropriate. Because we believe such a plan would benefit customers, we plan to work with stakeholders to explore mechanisms that will facilitate development and deployment of contingency plans. Legislation recognizing the appropriateness of investments needed to develop a Commission-approved contingency plan would minimize the disincentive to engage in advanced planning and may be appropriate.

As we discuss this idea with stakeholders, we believe a contingency plan should ultimately seek to develop "shelf-ready" projects. This would allow utilities to incur and recover reasonable expenses necessary to develop a "shelf-ready" facility, to be installed in the event it is needed to address a sudden increase in load or an unexpected loss of resources. We believe such a plan would be in the best interests of our customers, allowing us to avoid potentially higher costs of replacement power if we are forced to obtain it in a constrained market. We look forward to working with interested parties to develop and obtain approval for a balanced and effective contingency plan.

XI. CONCLUSION

We appreciate this opportunity to update the Commission and interested stakeholders on changing circumstances surrounding our resource plan. Through this update, we have provided the most recent forecast data and our analysis of the impacts that forecast has on our resource plan. In light of all of the factors described in this update, significant portions of our initial Five-Year Action Plan remain appropriate and should continue to be implemented.

We ask the Commission to conclude this planning cycle by approving our revised Five-Year Action Plan. This plan is designed to maximize benefits for customers and ensure that we meet their needs in a cost-effective manner. In summary, we respectfully request that the following items be implemented as part of our revised Five-Year Action Plan:

- *Black Dog Repowering Project.* Our revised Five-Year Action Plan includes withdrawal of our application for a Certificate of Need for the Black Dog Repowering Project in Docket No. E002/CN-11-184. Our latest forecasts and analysis show that the next generating resource is no longer needed in 2016; thus we can monitor the timing and need for additional resources in our next resource planning cycle. We intend to make the filings necessary to withdraw from the certificate of need proceeding and related site and route permit proceeding, Docket No. E002/RP-11-307.

- *Prairie Island Capacity Uprate Program.* We have made considerable progress in implementing this capacity increase program based on the Commission's prior authorizations in Dockets E002/CN-08-509 and E002/CN-08-510. In light of our experience with a similar program at Monticello and other recent events including increased regulatory scrutiny from the accident at Fukushima Daiichi, we recommend additional assessment of the Prairie Island program. We intend to provide a complete analysis of these issues in a changed circumstances filing.

- *Wind Procurement.* We have purchased significant wind resources and have adequate generation and RECs for several years. As the PTC expires at the end of 2012 and is not expected to be renewed, we plan to reassess the pace of our wind power acquisition program after 2012.

- *Contingency Plan.* In light of the potential for demand to fluctuate and the long time-lines involved in developing and constructing major infrastructure, we propose to engage in a constructive dialogue with stakeholders on ways to be prepared to react to future circumstances and unexpected changes in demand.

- *DSM*. DSM continues to deliver value for our customers and we are excited to continue working with our stakeholders to achieve 1.5% DSM energy savings as part of the revised Five-Year Action Plan.

- *Manitoba Hydro*. Extending our relationship with Manitoba Hydro will allow us to continue providing customers with economical service from renewable resources.

- *Monticello EPU*. We continue to include the EPU at the Monticello as part of the revised Five Year Action Plan.

Finally, we respectfully request that the Commission conclude this planning cycle based on our revised Five-Year Action Plan and schedule the next planning cycle to begin in the Spring of 2013.

System Peak (MW)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		Growth
20%	9,422	8,814	8,798	8,871	8,957	9,030	9,116	9,189	9,271	9,371	9,450	9,511	9,605	9,658	9,744		0.24%
50%	9,785	9,215	9,217	9,305	9,402	9,495	9,581	9,672	9,760	9,839	9,918	9,981	10,031	10,069	10,094		0.22%
80%	10,154	9,670	9,739	9,902	10,055	10,219	10,396	10,521	10,692	10,823	10,990	11,135	11,270	11,403	11,533		0.91%
Reserve Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%		
System Energy (GWh)																	
20%	44,708	44,510	44,147	44,344	44,546	44,801	44,883	45,055	45,232	45,419	45,591	45,741	45,853	46,021	46,243		0.24%
50%	45,785	45,860	45,669	45,999	46,338	46,720	46,927	47,223	47,499	47,799	48,096	48,308	48,535	48,813	49,123		0.50%
80%	46,865	47,233	47,181	47,675	48,140	48,652	48,956	49,394	49,771	50,168	50,574	50,891	51,218	51,595	51,993		0.74%
Gas Price ($/mmBtu)	$4.20	$4.39	$4.86	$5.16	$5.50	$5.95	$6.22	$6.34	$6.60	$6.85	$7.27	$7.57	$7.83	$8.06	$8.35		5.03%
Nuclear Fuel Price ($/mmBtu)	$0.91	$0.88	$0.90	$0.89	$0.98	$0.99	$1.01	$1.04	$1.05	$1.07	$1.11	$1.13	$1.17	$1.19	$1.21		2.04%
CO2 Pricing ($/ton)																	
Base	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
Mid	$0.00	$17.00	$17.40	$17.81	$18.23	$18.66	$19.10	$19.55	$20.02	$20.49	$20.97	$21.47	$21.97	$22.49	$23.02		
Low	$0.00	$9.00	$9.21	$9.43	$9.65	$9.88	$10.11	$10.35	$10.60	$10.85	$11.10	$11.36	$11.63	$11.91	$12.19		
High	$0.00	$34.00	$34.80	$35.62	$36.46	$37.33	$38.21	$39.11	$40.03	$40.98	$41.94	$42.93	$43.95	$44.98	$46.04		
Late	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$4.54	$6.05	$6.50	$15.77	$16.94	$18.19	$19.54	$20.99		
CSAPR Rules																	
SO2 Pricing ($/ton)	$0	$834	$674	$627	$467	$352	$274	$166	$63	$0	$0	$0	$0	$0	$0		
SO2 Allowances (tons)	0	24500	24500	24079	24079	23053	23053	23053	21005	21005	21005	21005	21005	21005	21005		
NOx Pricing ($/ton)	$0	$924	$874	$832	$508	$469	$396	$322	$238	$203	$196	$207	$218	$229	$240		
NOx Allowances (tons)	0	16860	16860	16846	16846	16154	16154	16154	14772	14772	14772	14772	14772	14772	14732		
Wind Expansion Plan (MW)	0	0	100	100	100	100	100	100	100	200	0	100	200	0	100		
Level Wind Expansion Plan (MW)	0	0	0	0	0	0	0	0	0	100	0	0	200	100	0		
Short Term Capacity (MW)	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Resource Additions	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
		Slayton 1 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	WIND_PPA 13 MW	MH375500 125 MW	WIND_PPA 13 MW	WIND_PPA 13 MW		WIND_PPA 13 MW		
		Sherco 3 8 MW	PrRose 26 MW		P Island 2 55 MW	P Island 1 55 MW				WIND_PPA 13 MW			WIND_PPA 13 MW				
		SAF Hydr 3 MW	ND_50 6 MW		MH375500 375 MW												
		NthShaok 0 MW	Monti 1 67 MW		DIV350IN 350 MW												
		GoodhuNS 10 MW	CrownHyd 1 MW														
		Fch Isld 3 61 MW	Borders 19 MW														
		DiamondK 0 MW															
		Danielsn 3 MW															
		CommWndN 4 MW															
		BigBlue 5 MW															
Resource Retirements	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
			Key City 4 -14 MW		MH500 -500 MW	Coyote 1 -100 MW	Rapidan -3 MW	Wilmarth 1 -18 MW	WSMorrn -6 MW	MNMethan -5 MW	Fch Isld 4 -64 MW	St.Cloud -7 MW	St Paul -25 MW	Fch Isld 1 -21 MW	Stahl -1 MW		
			Key City 3 -14 MW		Div150In -168 MW		Div200In -224 MW	Viking -2 MW	WindPowr -3 MW		Fch Isld 3 -61 MW		MNDakota -19 MW	Chanaram -11 MW	MNWind -1 MW		
			Key City 1 -14 MW					Red Wing 1 -20 MW	Moraine -7 MW		Byllesby -2 MW			Bayfront 6 -29 MW	MH375500 -500 MW		
			Granite 4 -14 MW					HERC -34 MW	KODARAHR -12 MW					Bayfront 5 -22 MW	LkBnton2 -13 MW		
			Granite 3 -14 MW					Flambeau 1 -14 MW						Bayfront 4 -19 MW	Invenerg 2 -161 MW		
			Granite 2 -14 MW												Invenerg 1 -161 MW		
			Granite 1 -13 MW												DIV350IN -350 MW		

Thermal Units

	Capital Cost ($ millions)	Firm Capacity (MW)	Heat Rate (mmBtu/MWh)
Gas CT	$124	195	9.888
Gas CC	$671	729	6.713
Coal	$1,922	500	9.357
Coal w/CCS	$2,733	500	12.359

Renewable Resource

	Capital Cost	Nameplate (MW)	Capacity Credit	Capacity Factor	FOM ($000/yr)
Wind	$1,800	100	12.9%	40%	$2,000

Wind capital cost is converted to a PPA cost of $47.39 escalating at 2.36%

CERTIFICATE OF SERVICE

I, Lindsey Didion, hereby certify that I have this day served copies of the foregoing document on the attached lists of persons.

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

xx by email; or

xx by electronic filing.

DOCKET NO. E002/RP-10-825
DOCKET NO. E002/CN-08-509

Dated this 1st day of December 2011.

/s/
____
Lindsey Didion

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CERTIFICATE OF SERVICE

I, Lindsey Didion, hereby certify that I have this day served copies of the foregoing document on the attached lists of persons.

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

xx by email; or

xx by electronic filing.

DOCKET NO. E-002/CN-11-184

Dated this 7th day of December 2011.

/s/

____

Lindsey Didion

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CALPINE CORPORATION
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North Region Business Office
500 Delaware Avenue
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March 23, 2012

The Honorable Richard C. Luis
Administrative Law Judge
P.O. Box 64620
St. Paul, MN 55164-0620

Via Electronic Filing

Re: In the Matter of Application of Northern States Power Company for a Certificate of Need for the Black Dog Generating Plant Repowering Project MPUC Docket No. E-002/CN-11-184, OAH Docket No. 7-2500-22228-2

Dear Judge Luis:

Pursuant to your Order dated January 25, 2012, Calpine provides its response to the March 1, 2012 analysis filed by the Minnesota Department of Commerce, Division of Energy Resources (the “Department”).

Introduction

The Department had informed the parties on December 15, 2011 that it “does not agree with Xcel at this time that withdrawal of the certificate of need application or certification of this matter to the Commission is appropriate.” The Department’s update of March 1, 2012 affirms its earlier position and states that, in light of its further analysis, “the Department recommends that the instant proceeding continue and that the Xcel Motions be denied.”

Calpine agrees with the Department that Xcel’s motions should be denied and this docket should proceed. The questions the Commission has referred to the Office of Administrative Hearings in this contested case remain relevant, and a contested case will permit a comparative examination of the competing Mankato and Black Dog proposals. In addition, the new information that has been presented by the Department supports the continuation of this process, which is the most expeditious way to review the differences between the modeling results identified by the Department and by Xcel.

Discussion

Xcel’s Motion to Withdraw was premised on its assertion that it has sufficient generation to meet its customers’ needs through at least 2018 and that it can no longer justify development of the Black Dog project. Xcel further claims that it is more likely that the next needed resource will be a combustion turbine (i.e., a "peaking" unit) rather than a combined cycle unit.[1]

The Department has not yet completed its review of Xcel's revised forecast or its comparison of the Xcel and Calpine proposals, but has concluded that new combined-cycle capacity may be needed "in the 2016 to 2018 time frame" based on its own Strategist modeling runs, which rely on different inputs than were used by Xcel: "our review of the Company's Strategist modeling resulted in several changes to the Company's inputs." The Department concludes that "the Commission may find it reasonable to expect that circumstances are likely to occur that will require Xcel to add additional generation within the next few years to serve its retail Minnesota load."

The Department's modeling produces a materially different result than Xcel's modeling <u>despite the fact</u> that the Department relied upon Xcel's most recent demand forecast. Even when using the <u>lowest</u> demand forecast of the three that Xcel presented over the course of the Black Dog certificate of need proceeding, the Department still finds that some amount of new combined-cycle capacity may be required as early as 2016.

In light of the fact that the Department is continuing to evaluate Xcel's demand forecast, both the forecast and the Strategist modeling are properly subject to examination in the contested case. For the new capacity necessary in the 2016 to 2018 time frame, the current proceeding is the best, if not the only, way to ensure that the most suitable project is available for deployment at that time.[2]

Calpine agrees with the Department that "one goal in resource planning and certificates of need is to arrive at a plan and projects that are stable across a range of forecasts." At some point, the Commission will adopt a forecast upon which to base its planning decisions, and long term resource planning cannot be held hostage to semi-annual swings in a demand forecast. The Commission would be taking an unnecessary

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[1] An additional issue that could be addressed in this contested case is whether the state needs new combined-cycle capacity or new peaking capacity. Calpine's Alternative Proposal could easily be amended to include the initial installation of peaking capacity that subsequently could be converted to combined-cycle. Addressing this in the context of the current proceeding could help avoid the need to engage in a new contested case proceeding when and if Xcel submits a certificate application for peaking capacity.

[2] In its March 1, 2012 filing, the Department states that its efforts have been hampered by "difficulties in obtaining data from the Company." Xcel's delay in providing information requested by the Department has also had an adverse impact on the filing of comments in the Integrated Resource Plan proceeding, Docket No. E002/RP-10-825, as identified in the Department's letter dated March 22, 2012: "Due to Xcel's delays in providing the data needed for the Department to review Xcel's new forecast, the Department requests an extension to May 21, 2012 to allow the Department enough time to complete the Strategist modeling of Xcel's IRP Update." Further delays in this contested case proceeding could have an adverse impact on the time within which suitable resources are available to meet the state's energy needs. Despite the delays experienced in this proceeding as a result of Xcel's motions, Calpine is able at this time to continue to offer the terms and conditions of its proposal in order to meet the state's resource requirements.

risk if it chooses to forego this opportunity to keep proposals for new combined-cycle capacity in the project pipeline.

The Commission is fortunate that the Department has its own Strategist modeling expertise and has access to the otherwise confidential information and input files Xcel uses in its modeling efforts. The initial results of the Department's analysis, as provided in its March 1 letter, confirm Calpine's belief that Xcel's Strategist modeling is highly sensitive to the input assumptions that Xcel used and should not necessarily be taken at face value. Xcel's analysis has been subject to an independent review by the Department -- a neutral third party -- which has come to a different conclusion, even while relying on Xcel's own forecast results. Resolving the discrepancy between the respective modeling results can only be accomplished by continuing the contested case.

Conclusion

In light of the information provided in the Department's March 1 letter and as argued by Calpine at the Second Prehearing Conference on January 11, 2012, it is inappropriate to terminate the contested case and the Black Dog certificate of need proceeding. Xcel's apparent belief that it will not be successful in this case is not sufficient justification to abandon the contested case. This proceeding concerns what is best for Minnesota ratepayers. The utility's determination that it no longer wants to pursue, or cannot ultimately justify, its self-build proposal should not prevent the Commission from examining whether Calpine's Alternative Proposal is, in fact, needed.

The contested case will allow the Commission to benefit from the Department's ongoing analysis of Xcel's forecast and to examine the discrepancy between the modeling performed by Xcel versus the modeling that has been performed by the Department. The contested case will provide valuable guidance in advising the Commission which of the two pending proposals is the best option to help meet the state's resource needs.

Calpine, therefore, respectfully recommends that Xcel's Motions be denied and that the contested case continue.

Sincerely,

/s/ Steven Schleimer

Steven Schleimer
Vice President, Government and Regulatory Affairs
John Flumerfelt
Director, Government and Regulatory Affairs

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 - Alternative Proposal	MPUC Docket No. E-002/CN-11-184 OAH Docket No. 7-2500-22228-2

I, Laura I. Taggart, hereby certify that I have on this 23rd day of March, 2012 filed a true and correct copy of the foregoing document with the Minnesota Public Utilities Commission by electronically filing it on www.edockets.state.mn.us. I further certify that I have served the foregoing document on the attached service list by selecting the automatic electronic service option to serve those who have elected to receive documents in this docket by electronic methods, and by depositing same in the U.S. mail to those who have elected to receive documents in this docket by paper service.

Dated this 23rd day of March, 2012.

/s/ Laura I. Taggart

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OAH 7-2500-22228-2
PUC Docket No. E-002/CN-11-184

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Petition of Northern States Power Company for Certificate of Need for the Black Dog Generating Plant Repowering Project

ORDER GRANTING MOTION TO WITHDRAW AND ORDER TO CERTIFY

On December 7, 2011, Northern States Power Company (NSP) filed a Motion to Withdraw its Application in this matter. The two other active parties in this proceeding, Calpine Corporation (Calpine), and the Minnesota Department of Commerce (Department, DOC) opposed the Motion by NSP.

James R. Denniston, Assistant General Counsel, appeared on behalf of NSP. Julia E. Anderson, Assistant Attorney General, appeared on behalf of the Department. Peter L. Gardon, Esq., Reinhart Boerner Van Deuren, Steven Schleimer, Vice President, Government and Regulatory Affairs, and John Flumerfelt, Director, Government and Regulatory Affairs, appeared on behalf of Calpine.

The final Brief in this matter was received on May 2, 2012. That round of Briefs was requested by the Administrative Law Judge (ALJ), asking Counsel to comment on NSP's March 30 and April 2, 2012, announcement(s) (in separate dockets) that it would be re-considering the previously-approved uprate of its power output at the Prairie Island Nuclear Plant, due to a change of circumstances.

The Prairie Island announcement was based on the same long-range forecasts made by NSP of its required energy needs that caused it to file its Motion to Withdraw its Application.[1]

Having taken this matter under advisement, and based on all the proceedings herein, the Administrative Law Judge makes the following:

ORDERS

IT IS ORDERED that NSP's Motion to Withdraw its Application for a Certificate of Need for the Black Dog Generating Plant Repowering Project is **GRANTED.**

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[1] May 1, 2012 Memorandum of James R. Denniston.

IT IS ORDERED FURTHER that NSP's Request to Certify its Motion to the Minnesota Public Utilities Commission, pursuant to Minn. R. 1400.7600, is **GRANTED.**

IT IS ORDERED FURTHER that NSP's Withdrawal of its Application for a Certificate of Need in this docket is **CERTIFIED** to the Commission.

Dated: May 30, 2012

Richard C. Luis
RICHARD C. LUIS
Administrative Law Judge

MEMORANDUM

The Department initially opposed NSP's Motion. In its final Brief, the Department changed its earlier position that the Company should not be allowed to withdraw its Petition. It is noted that a decision in this matter was postponed several months while the Department updated its research/analysis of the forecast of future demand for energy NSP had filed to support the original Motion to Withdraw and Request Certification. No parties opposed the Department's request to complete its analysis before proceeding further.

After that analysis was completed, the Department still opposed NSP's Motion.[2] Xcel and Calpine replied to the Department's filing on March 23, 2012. After the matter was taken under advisement by the Administrative Law Judge (ALJ), NSP submitted a filing, on March 30 and April 2, 2012, respectively, in Dockets 08-509 (the Prairie Island Uprate Docket), and 10-825 (NSP's 2011-2025 Integrated Resource Planning Docket).

The filing, entitled "Notice of Changed Circumstances and Petition Related to Prairie Island Extended Power Uprate," noted that NSP was placing its Prairie Island nuclear plant uprate project on hold, based on forecasts of future generation needs in the entire system, the costs of alternative resource options and uncertainties in the federal licensing process. NSP asked the Commission to reaffirm that the Prairie Island project remains in the public interest before proceeding further.

Based on NSP's Prairie Island filing, the ALJ requested the parties to comment further on whether NSP should be allowed to withdraw its Petition in this docket. The ALJ asked specifically whether the filing relating to a change in circumstances at Prairie Island was based on different/updated forecast data, or on the same data that supported the December, 2011 Motion to Withdraw in this docket.

[2] Letter, Anderson to ALJ 3/1/12.

In its latest filing, the Department of Commerce is not opposed actively to a withdrawal of the application in this proceeding. The Department recommends that the Administrative Law Judge obtain updated information from NSP regarding uncertainties bearing on NSP's forecasted demand and assumed supply-side portfolio, related to the Prairie Island uprate, the Monticello uprate, and the status of Sherco 3. The Department notes that those uncertainties bear on the need (or lack of need, as now claimed by NSP) to develop a natural gas generating facility producing 250 MW of baseload capacity at Black Dog.

Calpine has been consistent in its opposition to the Motion to Withdraw and Certification to the Commission. Calpine's filings note that, even when using the lowest (of three) demand forecasts presented by NSP during this Black Dog proceeding, some amount of new combined-cycle capacity may be required as early as 2016. The Department's March 2012 filing had made the same point.

Calpine believes it is appropriate to move forward with this Certificate of Need proceeding and deny NSP's Motion to Withdraw because it is appropriate to decide within the context of this contested case whether NSP's updated forecast information shows that there is no longer a need for the additional Black Dog generation.

The Administrative Law Judge does not agree with Calpine's argument that this Certificate of Need proceeding is mandated by law and necessary to address the need initially identified by NSP. Calpine argues that granting NSP's Motion to Withdraw, because NSP now cannot support the need for the Black Dog project, is inappropriate. The Administrative Law Judge does not agree. Indeed, if updated forecasts led the Company to make a decision that it will not have a need for the additional capacity to be provided by the Black Dog Project in 2016, there is no legal reason to bar the Company from withdrawing its Application.

Calpine argues that this docket is the appropriate forum for conducting discovery, filing testimony, and completing other aspects of a contested case, to test whether NSP's forecasts, as applied to Black Dog, support a withdrawal of the project.

However, the Administrative Law Judge believes that Xcel's reasoning in support of its Motion to Withdraw is sound. The need for future energy capacity that would have been supplied by the Black Dog Project, the uprates at Prairie Island and Monticello, and any circumstances surrounding Sherco 3, are all appropriately under consideration in the Integrated Resource Planning Docket for 2011-2025, currently before the Commission.

As noted in its final Brief, NSP believes that the Commission's decision on its Prairie Island Uprate, and on withdrawal of the Black Dog Certificate of Need Application, may need most appropriately to be considered in a proceeding that can examine the size, type and timing of its next resource addition, and all related issues.

NSP argues, and the ALJ agrees, that referring this matter to the Commission would allow the Commission to provide input and guidance on the best way to move forward. The Commission could then restructure and clarify goals of the proceeding to better address all factors that may impact this and other generation resource decisions. Those factors include load forecasts, the Company's proposed generation projects currently under review, the costs of other generation options in the marketplace, and alternative competing projects.

All the factors listed in the preceding paragraph make it appropriate to allow withdrawal of the NSP's Application in this proceeding, and to certify the matter to the Commission under Minn. R. 1400.7600.

The legal standard for direct Commission review of a Motion in a matter assigned to an ALJ is stated in the Rule governing Certification of Motions to Agency, Minn. R. 1400.7600, which provides, in relevant part:

...

> Any party may request that a pending motion or a motion decided adversely to that party by the judge before or during the course of the hearing...be certified by the judge to the agency. In deciding what motion should be certified, the judge shall consider the following...
>
> > B. Whether a final determination by the agency on the motion would materially advance the ultimate termination of the hearing...

The Administrative Law Judge is persuaded that Minn. R. 1400.7600 B is applicable here. It is within the purview of the Public Utilities Commission to decide, likely within the context of a docket considering the Company's overall energy needs and forecasts, whether it is appropriate to withdraw the Company's Application for developing 250 MW of additional power at its Black Dog Generating Plant.

R. C. L.

MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS

600 North Robert Street
Saint Paul, Minnesota 55101

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May 30, 2012

See Attached Service List

Re: ***In the Matter of the Petition of Northern States Power Company for Certificate of Need for the Black Generating Plant Repowering Project*; PUC Docket No. E-002/CN-11-184**
OAH Docket No. 7-2500-22228-2

Dear Parties:

The document listed below has been filed with the E-Docket system and served as specified on the attached service list.

Order Granting Motion to Withdraw and Order to Certify

Very truly yours,

Richard C. Luis mo.

RICHARD C. LUIS
Administrative Law Judge

Telephone: (651) 361-7843

RCL:mo

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
ADMINISTRATIVE LAW SECTION
P. O. BOX 64620
ST. PAUL, MN 55164-0620

CERTIFICATE OF SERVICE

Case Title: ***In the Matter of the Petition of Northern States Power Company for Certificate of Need for the Black Generating Plant Repowering Project***	**OAH Docket No. 7-2500-22228-2** **PUC Docket No. E-002/CN-11-184**

Mary Osborn certifies that on Wednesday, May 30, 2012, she served a true and correct copy of the attached Order Granting Motion to Withdraw and Order to Certify; by placing it in the United States mail with postage prepaid, or as indicated on the attached service list, addressed to the following individuals:

See Attached Service List	

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No
Linda	Chavez	linda.chavez@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 55101-2198	Electronic Service	No
Kodi	Church	kchurch@briggs.com	Briggs & Morgan	2200 IDS Center 80 South Eighth Street Minneapolis, Minnesota 55402	Electronic Service	No
Robert	Cupit	bob.cupit@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012198	Electronic Service	No
James R	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy	414 Nicollet Mall 5th Floor Minneapolis, MN 55401	Electronic Service	No
Bret	Eknes	bret.eknes@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	No
John	Flumerfelt	John.Flumerfelt@calpine.com	CalpineCorporation	500 Delaware Ave. Wilmington, DE 19801	Electronic Service	No
Peter	Gardon	pgardon@reinhartlaw.com	Reinhart Boerner Van Deuren s.c.	P.O. Box 2018 Madison, WI 53701-2018	Electronic Service	No
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No
Michael	Loeffler		Northern Natural Gas Co.	CORP HQ, 714 1111 So. 103rd Street Omaha, NE 681241000	Paper Service	No
Richard	Luis	Richard.Luis@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No
Bryan	Nowicki	bnowicki@reinhartlaw.com	Reinhart Boerner Van Deuren s.c.	22 E Mifflin St Ste 600 Madison, WI 53703-4225	Electronic Service	No
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Paper Service	No
James	Talcott	jim.talcott@nngco.com	Northern Natural Gas Company	1111 South 103rd Street Omaha, Nebraska 68124	Electronic Service	No
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No

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 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	ISSUE DATE: November 21, 2012 DOCKET NO. E-002/CN-11-184 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	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.

ORDER

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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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.

ORDER

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

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 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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414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

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.

[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

[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.

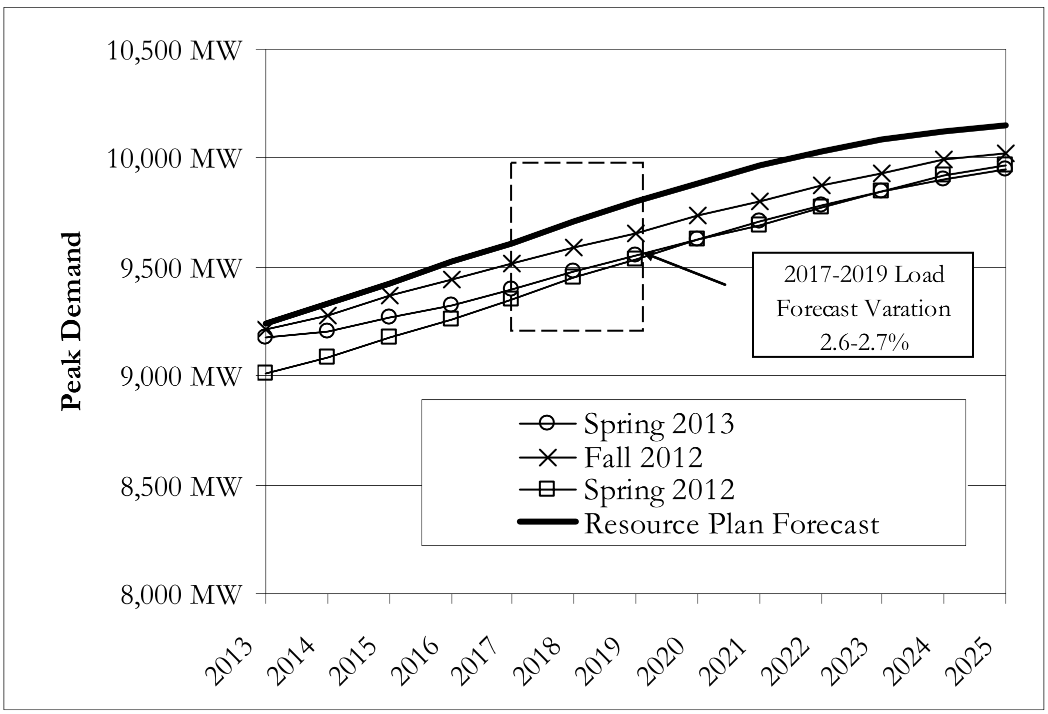
Xcel Energy meets its customers' needs for electricity with a combination of Company-owned-and-operated generating facilities, and long- and short-term power purchases. Our December 2011 Resource Plan Update forecast included the adjustments recommended by the Department in their June 2012 comments, 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 1st 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

[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:

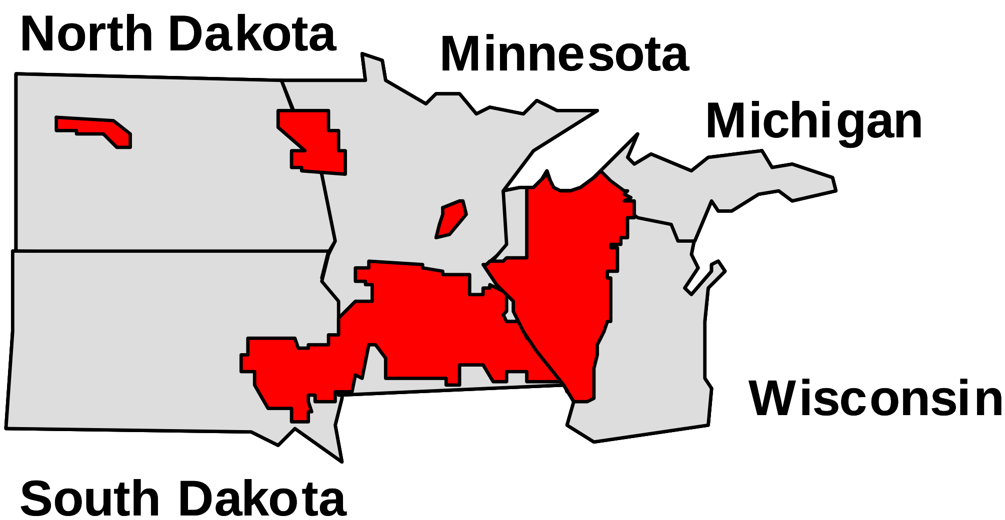
James R. Alders
Strategy Consultant
Xcel Energy
414 Nicollet Mall, GO 7
Minneapolis, MN 55401
james.r.alders@xcelenergy.com
(612) 330-6732

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

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[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

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[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:

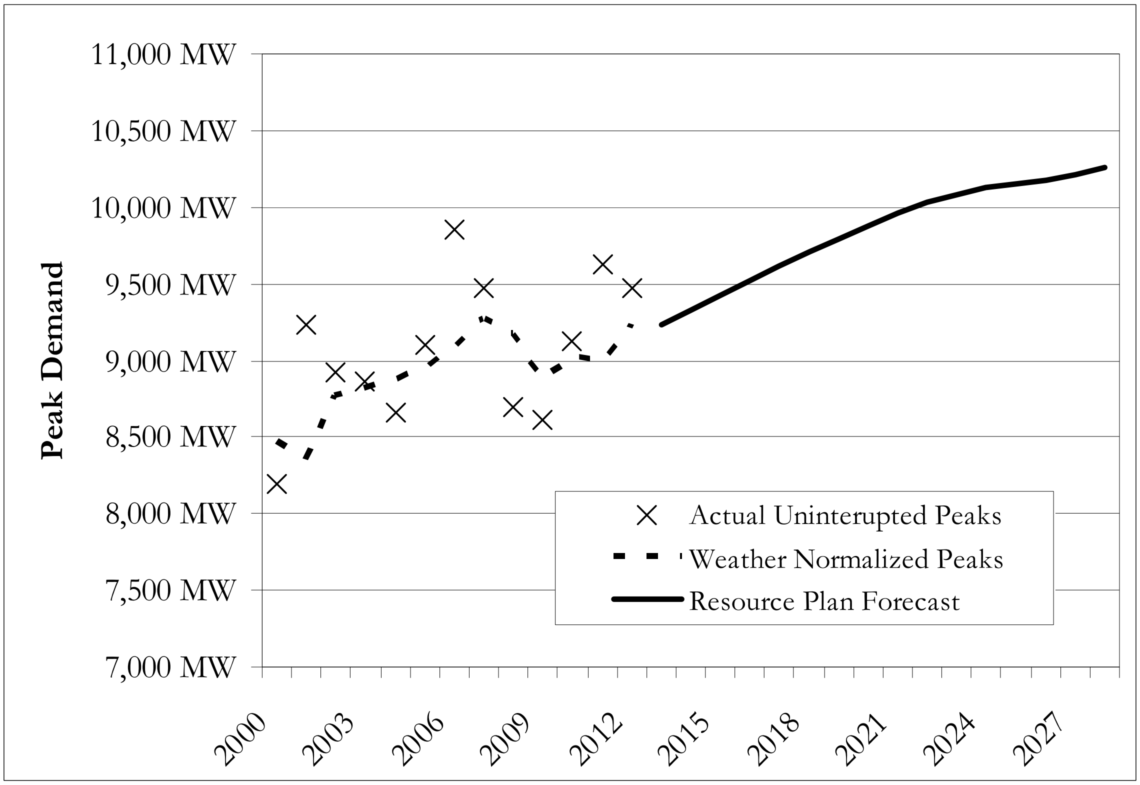
- *Identified Resource Need*- summarizing the inputs and factors that determined the level of need identified in our Resource Plan proceeding;
- *Forecast Uncertainty*- discussing two factors that contribute to uncertainty around our system resource needs – peak demand forecast variability and MISO reserve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

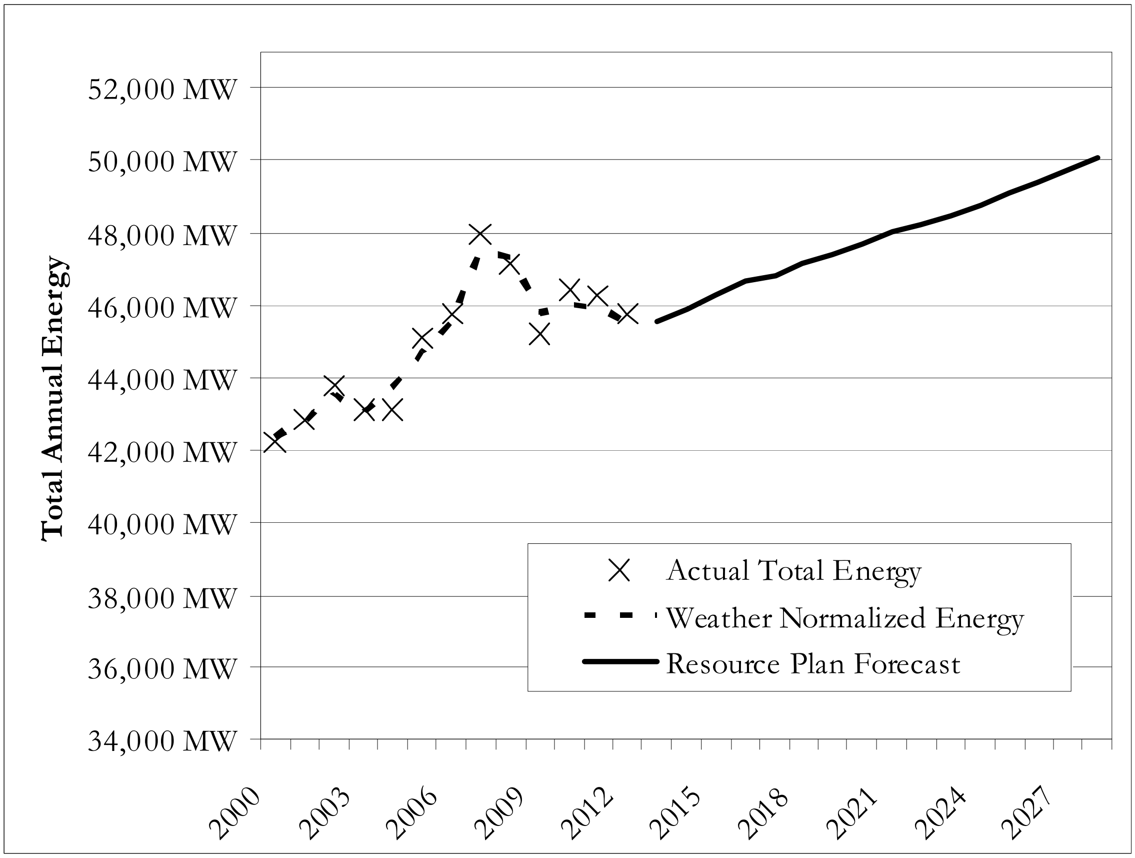
The assessment of resource need is based on three primary factors: peak demand forecast; reserve margins; and the maximum generation capability of existing resources. The load forecast used to establish the need approved by the Commission was the Company's Fall 2011 forecast, presented as an update to 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

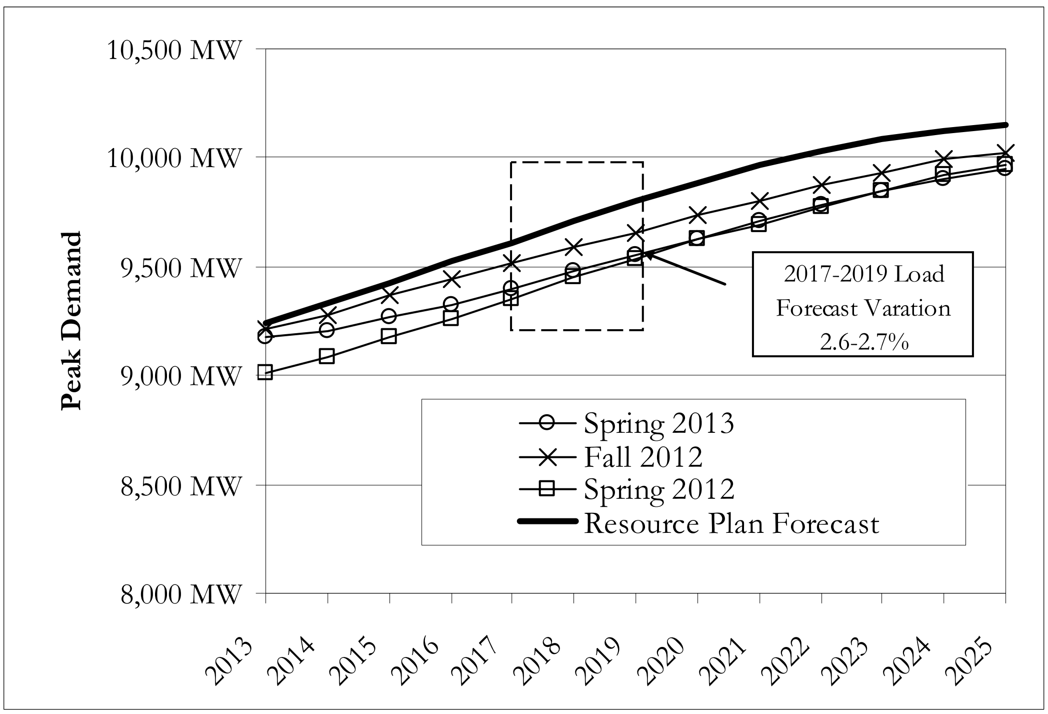
3.2 Forecast Uncertainty

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.

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[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

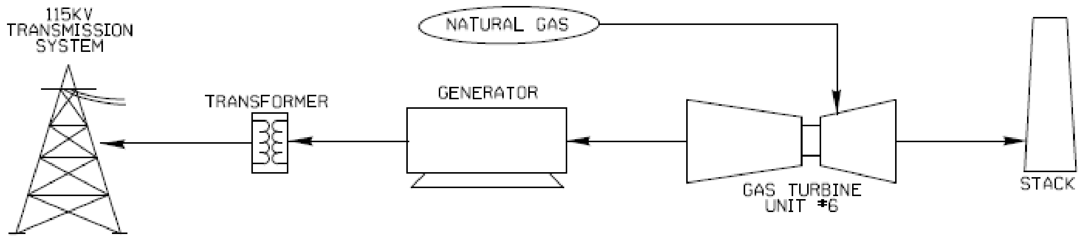
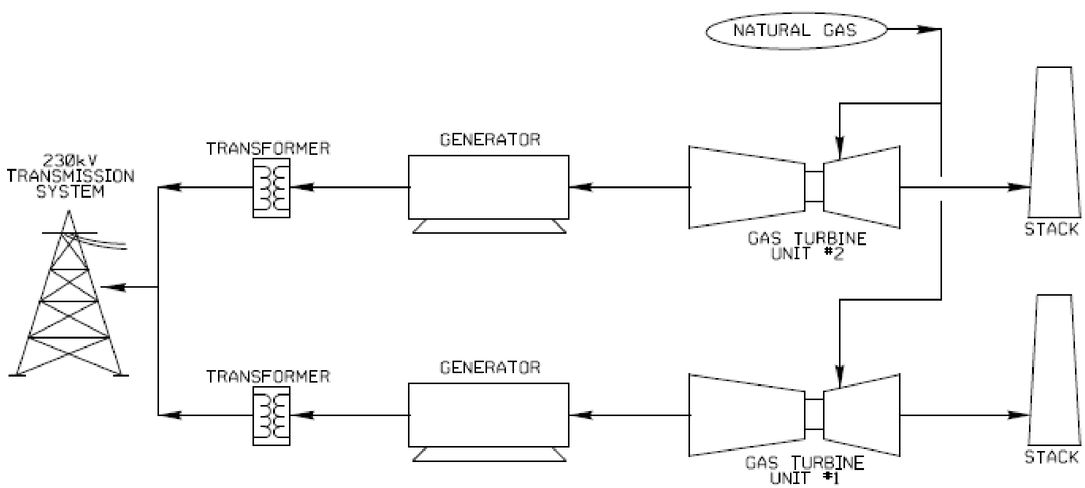


Figure 4-2
Schematic Diagram of a 2 Unit Simple Cycle Facility – North Dakota



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.

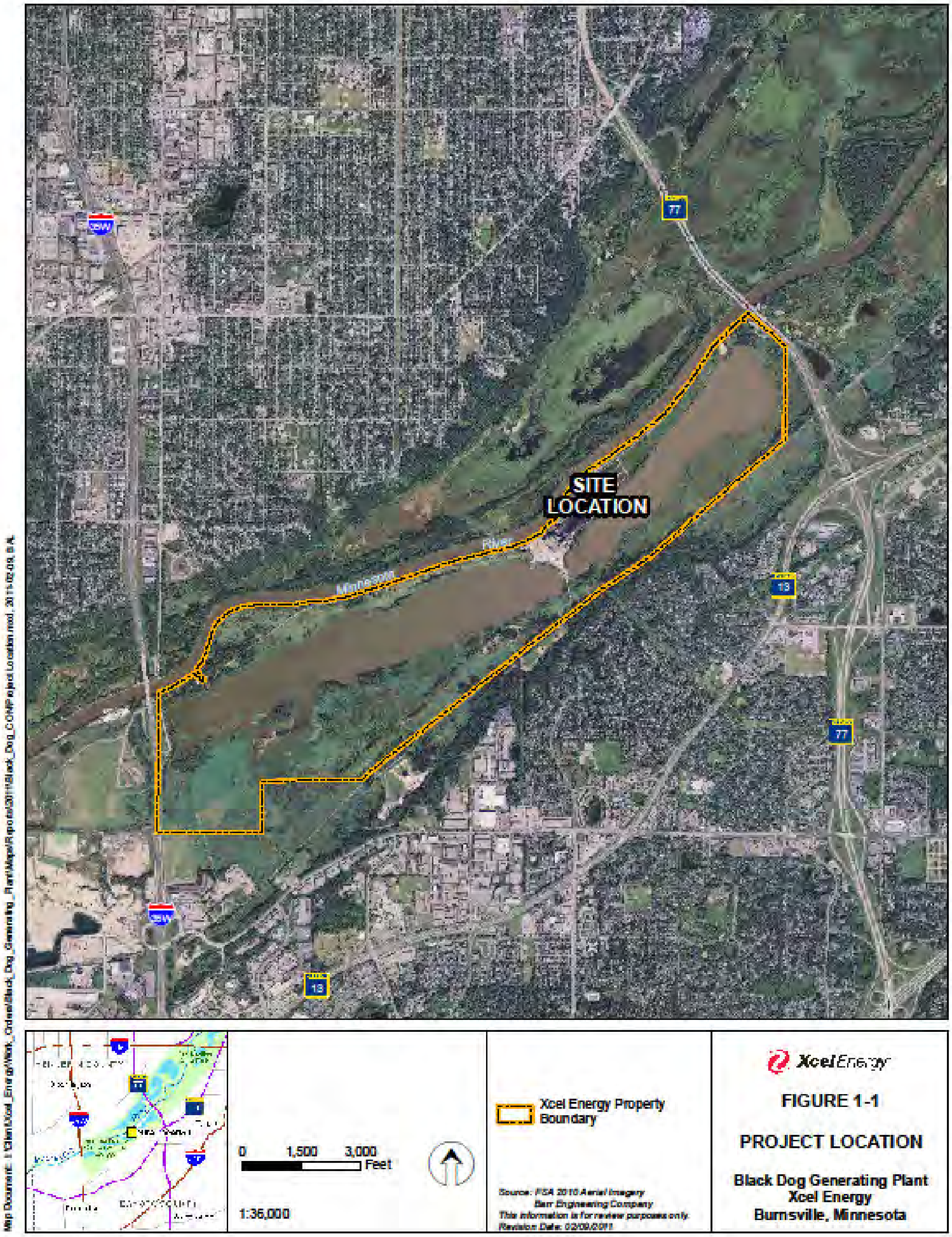
The combustion turbine units will be integrated into our remote dispatch control center. We expect to use the units for peaking load service, dispatching them after all lower cost and "must run" units. They are expected to be dispatched primarily during higher system load periods in the summer and winter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

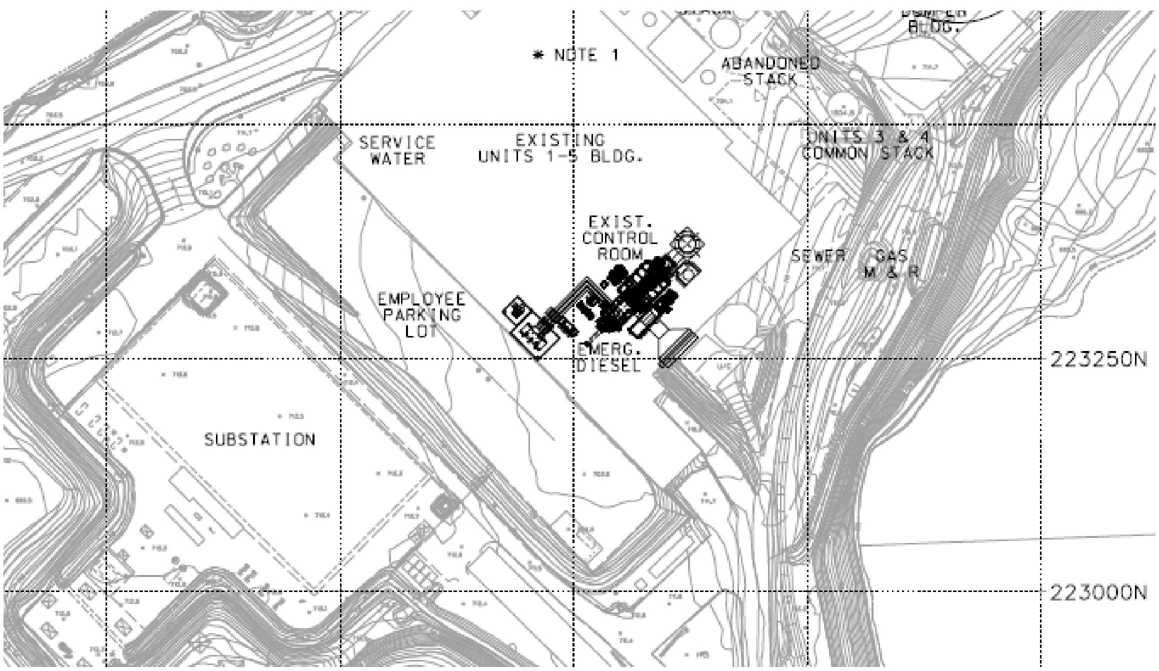


The original Unit 1 boiler/turbine and the Unit 2 boiler, installed at the site in the 1950s and fired on coal, were repowered with a natural gas combined-cycle unit (Unit 5), which includes a natural gas combustion turbine-generator combined with a heat recovery steam generator that delivers steam to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



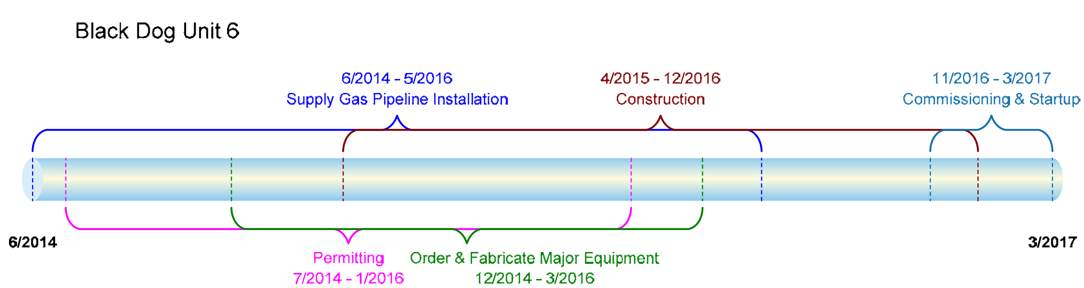
The exhaust stack will be approximately 200 feet tall and located adjacent to Unit 6, in the area of the existing Unit 4 boiler. The new unit will be connected to the existing 115 kV substation. Minor modifications to the existing 115kV switchyard will be required to connect it to the transmission system. 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.

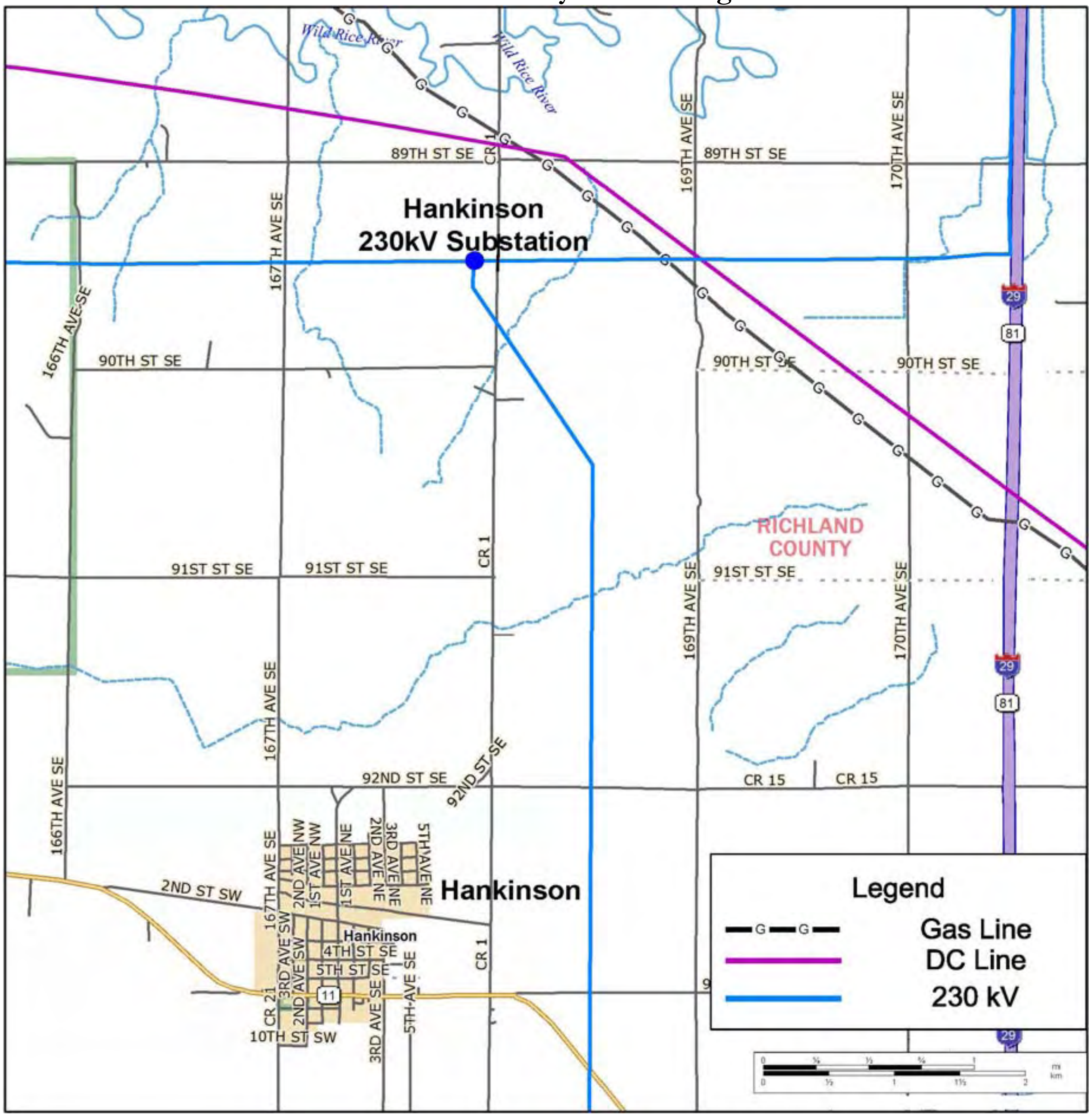
Figure 4-6
Black Dog Plant Rendering

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

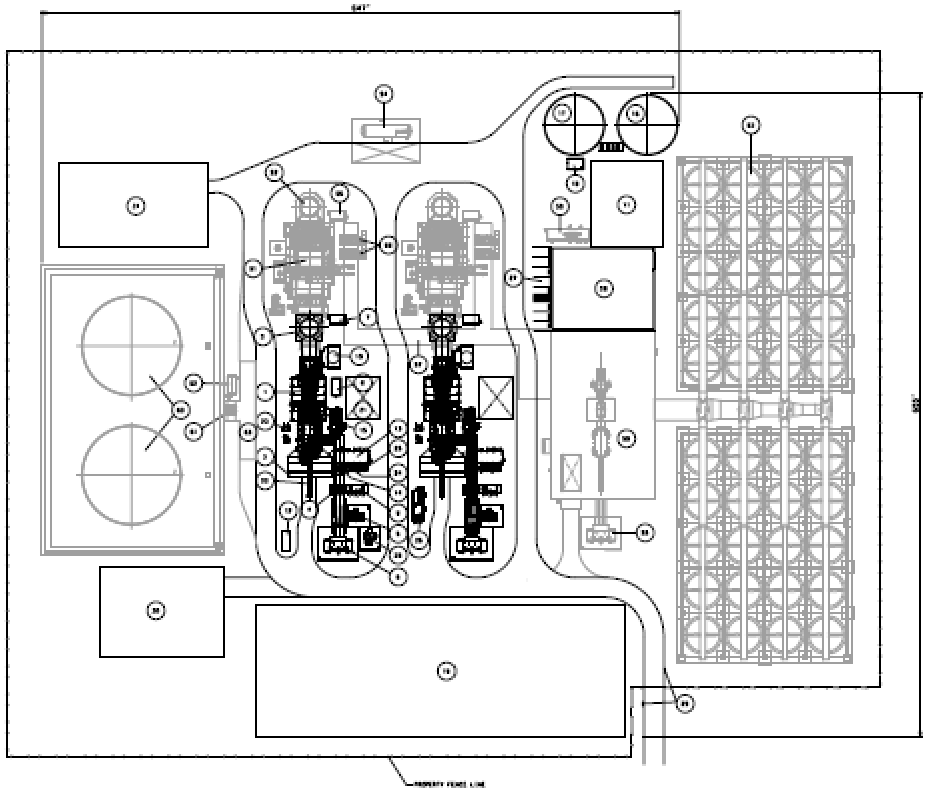
A specific plant site for the two Red River Valley units in southeast North Dakota has not been selected at this time. We anticipate the facility will be located in the general vicinity of Hankinson, North Dakota. The area provides access to the 230 kV transmission system serving the region and is near 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.

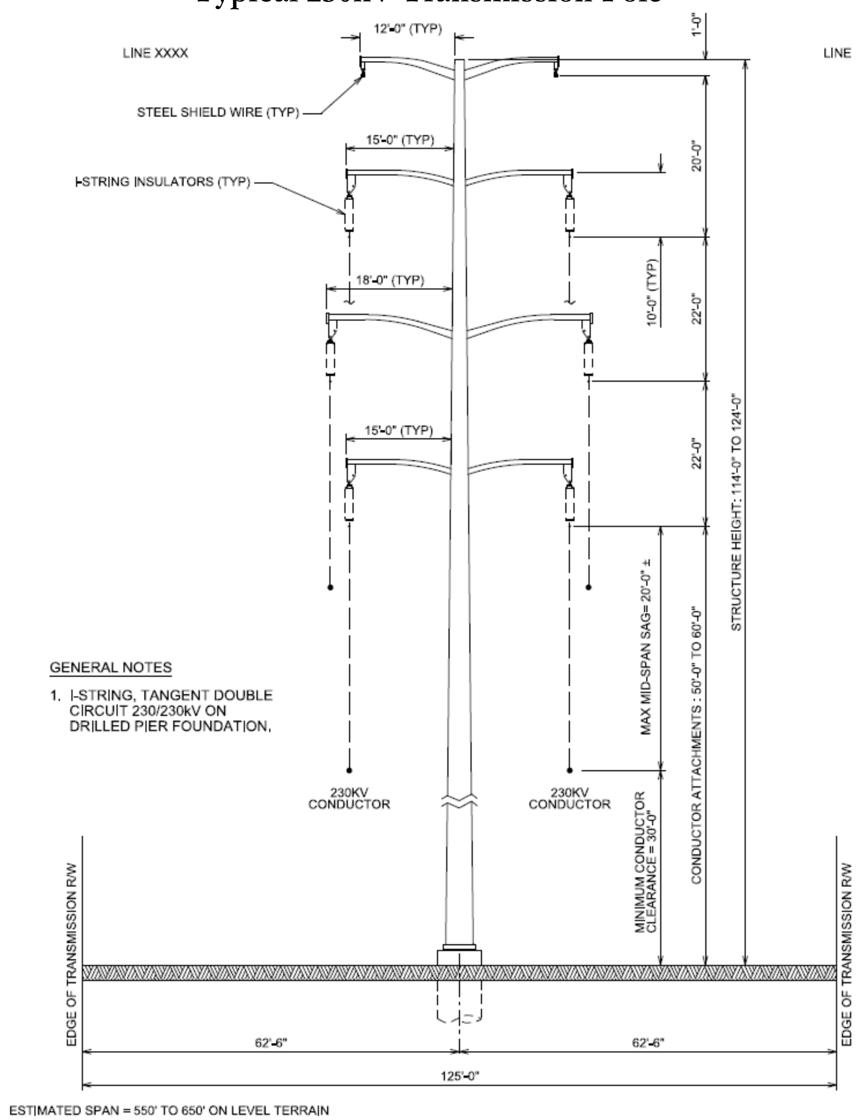
The output of the units depends on ambient weather conditions (primarily temperature and humidity). For purposes of this application, nominal generating capacity is considered to be about 214 MW at Summer ambient conditions of 88F and relative humidity of 42 percent, with an altitude of 900 feet above 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.

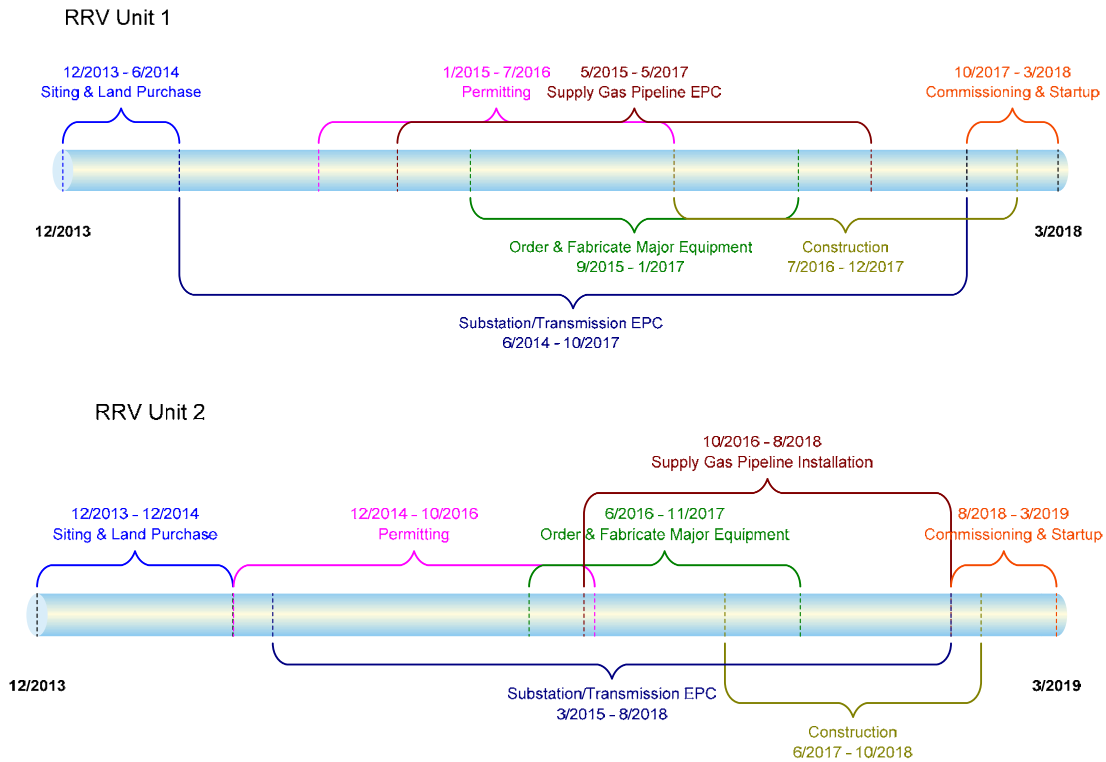
Figure 4-9
Typical 230kV Transmission Pole



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

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[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: **3 CTs @ 209 MW**	$88,922	-
Intermediate Unit: **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: 3 CTs @ 209 MW	$88,922	-
Biomass Alternative: 5 units @ 100 MW	$90,515	+$1,592
Solar Alternative: 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/m³)	National and Minnesota Ambient Standards (µg/m³)
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 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 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.S. Fish and Wildlife Service
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] 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

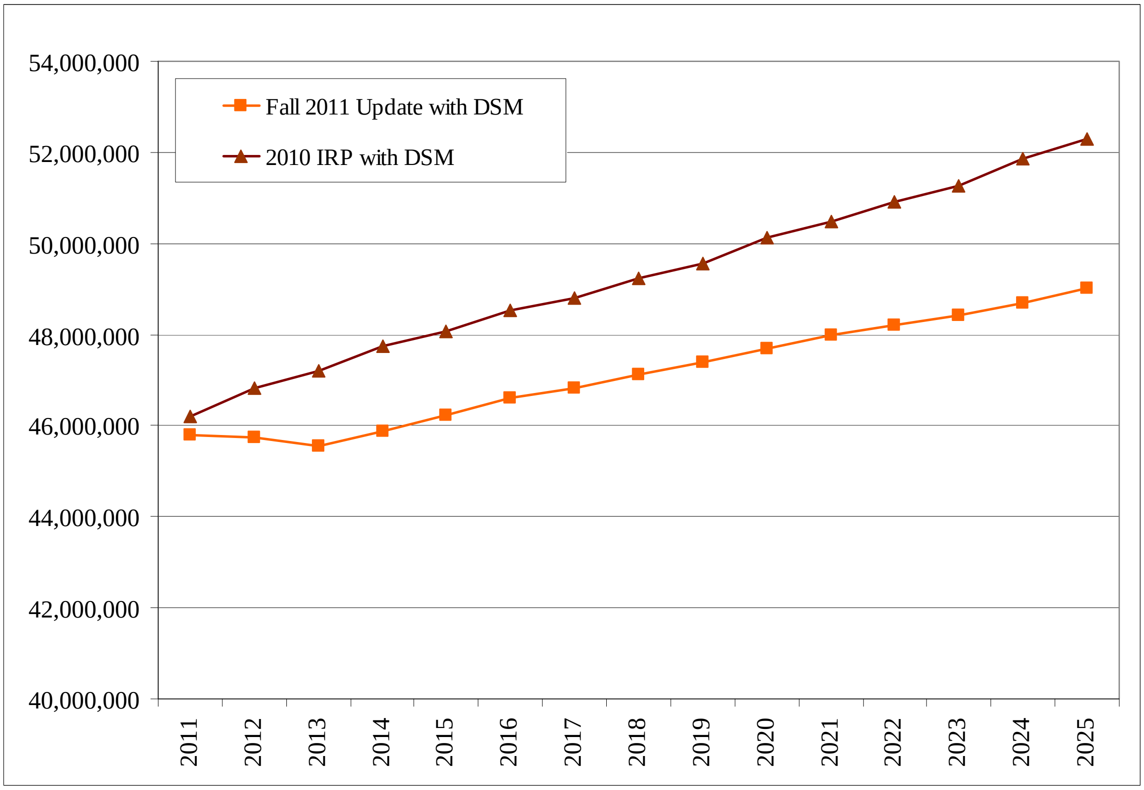
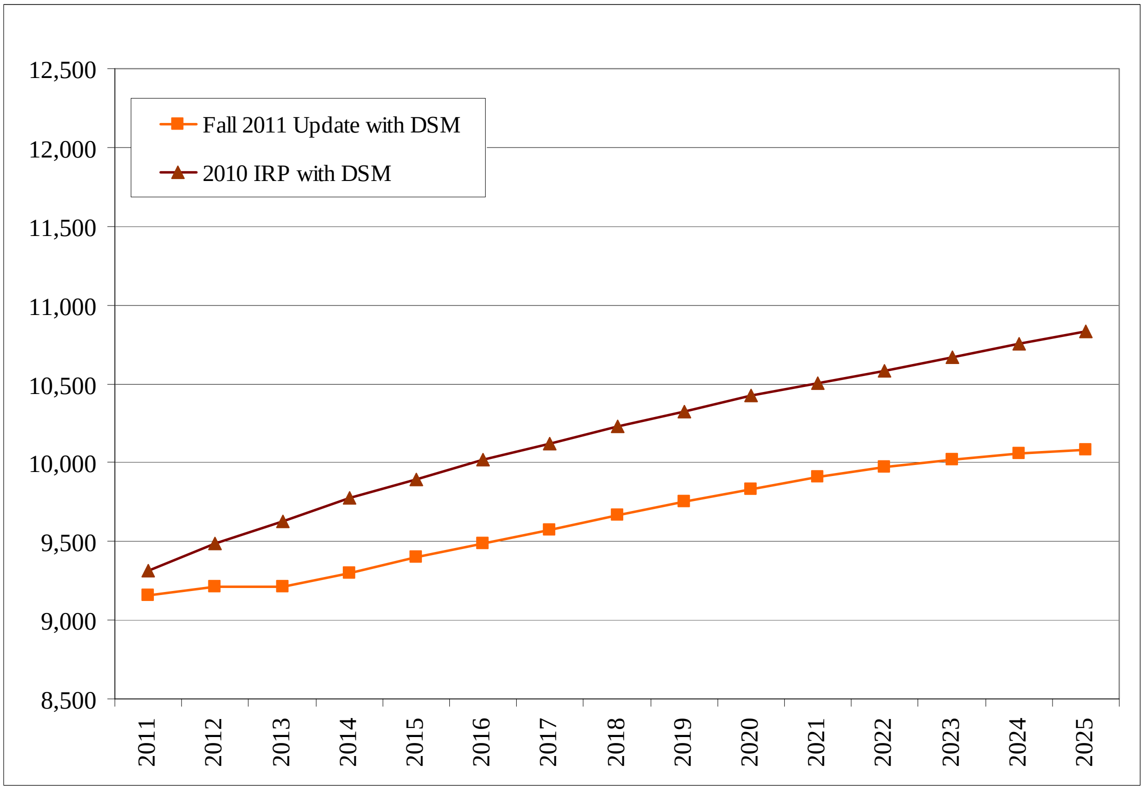


Figure 2 shows a comparison of the 50 percent peak demand forecast originally filed in the 2010 IRP with those developed in the Fall of 2011 (Resource Plan Update). Similar to the energy forecasts, the demand forecasts developed in the Fall of 2011 are lower than the original 2010 IRP forecast due to 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

[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 <u>Business Segment</u>
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 <u>Energy Efficiency Support Services</u>
1.1.1.4 <u>Low-Income Segment</u>
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

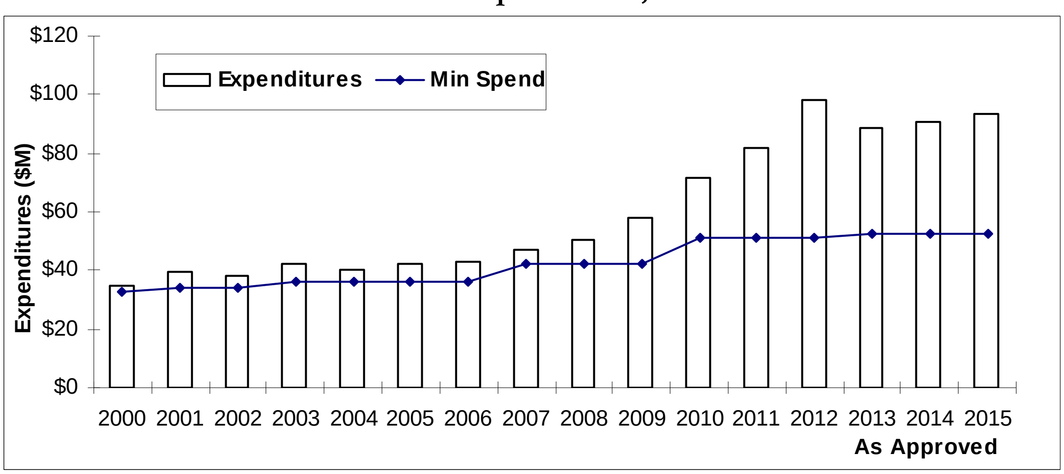


Figure 2
CIP Gas Expenditures, 2000-2015

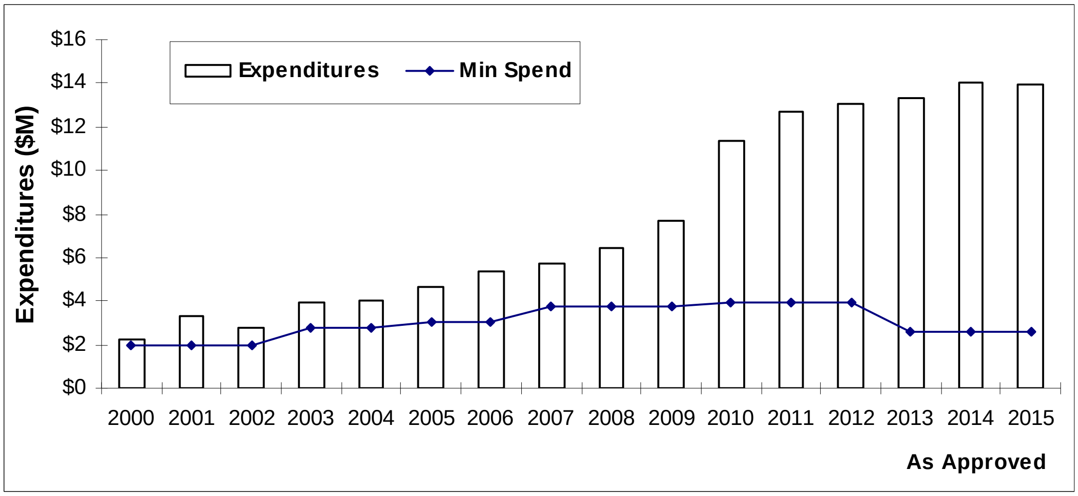


Figure 3
CIP Electric Energy Savings, 2000-2015

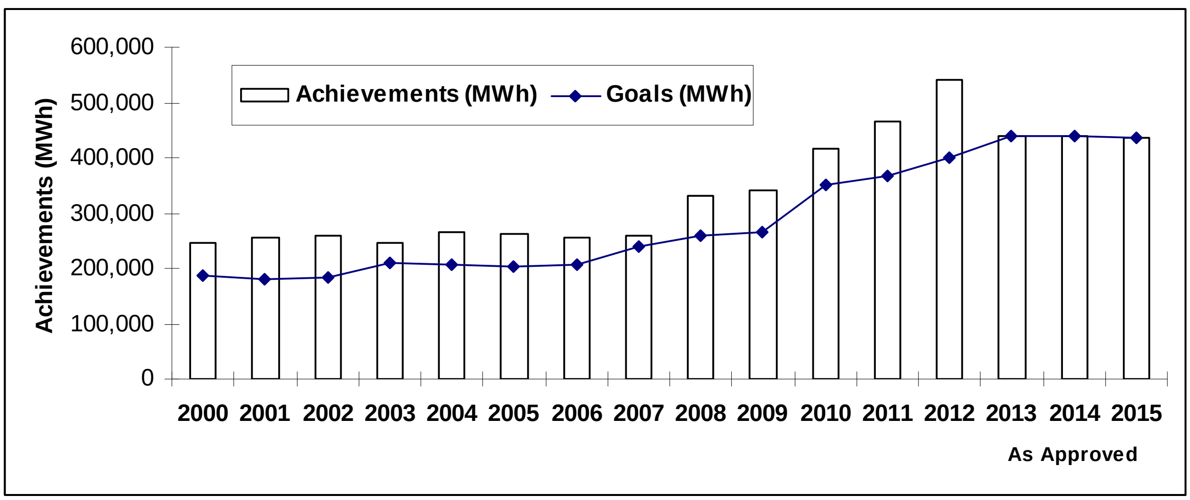


Figure 4
CIP Electric Demand Savings, 2000-2015

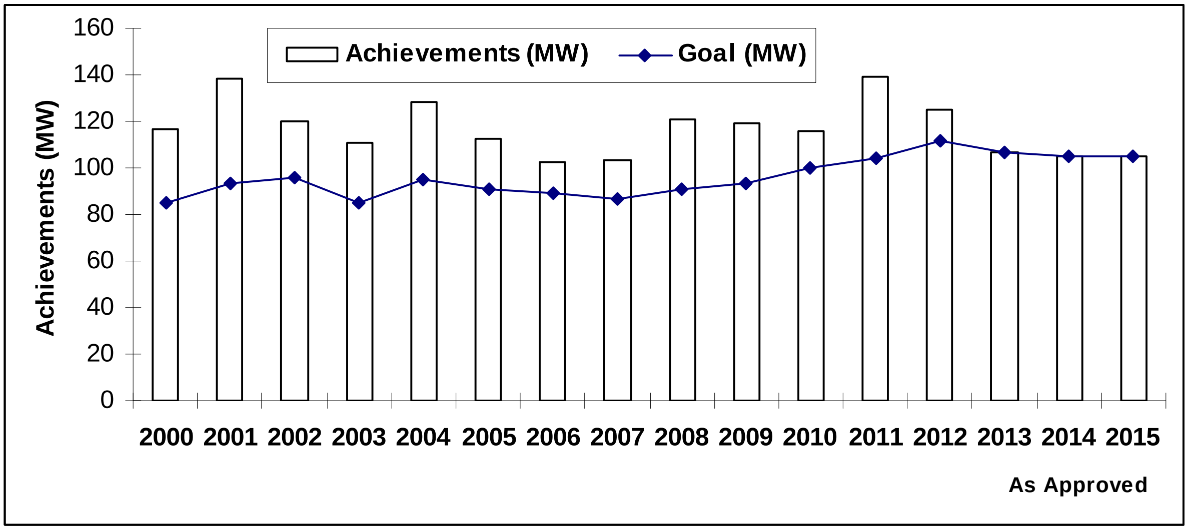
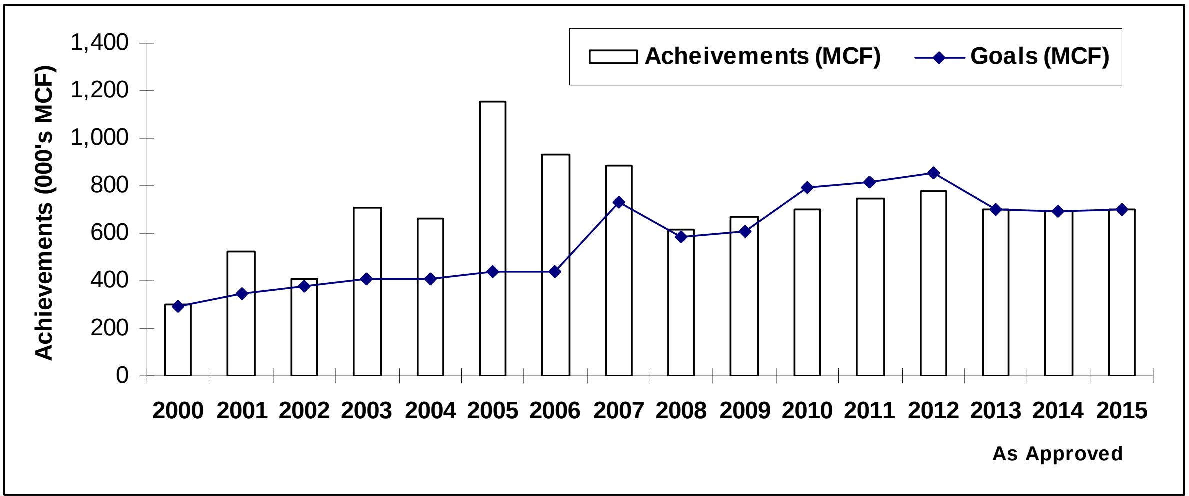


Figure 5
CIP Natural Gas Savings, 2000-2015



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 •summer, peak (95F) •winter, peak (-5F) •reference temperature, base load (59F) •Annual consumption (59F)	
7849.0320, C(3)	Heat Input (HHV) •summer, peak (95F) •winter, peak (-5F) •reference temperature, base load (59F)	
7849.0320, C(4)	Fuel (natural gas) Heat Value	
7849.0320, C(5)	Fuel Content: Sulfur Ash 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 •summer, peak (88F) •winter, peak (-5F) •reference temperature, base load (41F) •Annual consumption (41F)	
7849.0320, C(3)	Heat Input (HHV) •summer, peak (88F) •winter, peak (-5F) •reference temperature, base load (41F)	
7849.0320, C(4)	Fuel (natural gas) Heat Value	
7849.0320, C(5)	Fuel Content (Gas): Sulfur Ash 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 Surface Water Appropriation	50 GPM peak, 34 GPM daily average during Summer operation for evaporative cooling 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 (X% of site appropriation)
7849.0320, E (3)	Annual Project Surface Water Consumption Unit 6	215,100 acre-feet (50% of site appropriation) for existing Units 2 and 5 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 Surface Water Appropriation	50 GPM peak, 34 GPM daily average during Summer operation for evaporative cooling 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 0 if water is brought in by truck
7849.0320, E (3)	Annual Project Surface Water Consumption Unit 1 Unit 2	 0 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 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: 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 (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)

[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*

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 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*

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

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
ON-GOING CAPITAL COST: *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: 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

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 (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.

[TRADE SECRET DATA BEGINS...

NET CAPACITY :

	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

[TRADE SECRET DATA BEGINS...

HEAT RATE:

	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 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*

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:

…TRADE SECRET DATA ENDS]

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

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

2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
[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
	[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: **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

[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 (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*

[TRADE SECRET DATA BEGINS…

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028

…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…										
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*

NET CAPACITY : Maximum Capacity

	Summer	Average	Winter
Maximum Capacity	*[TRADE SECRET DATA BEGINS…*		*…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,*

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:

		Average
		[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%)	
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
ON-GOING CAPITAL COST *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 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.

[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 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]

[TRADE SECRET DATA BEGINS…

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023

…TRADE SECRET DATA ENDS]

Capital Notes: Nominal dollars

ANNUAL O&M COSTS

Nominal dollars

[TRADE SECRET DATA BEGINS…

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027

…TRADE SECRET DATA ENDS]

Notes: Minor annual O&M to maintain pipeline servicing facility.

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 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

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.

		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 :

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.

[TRADE SECRET DATA BEGINS…

NET CAPACITY :	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

[TRADE SECRET DATA BEGINS…

HEAT RATE:	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]

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023

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

Capital Notes: Nominal dollars

ANNUAL O&M COSTS

Nominal dollars

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027

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

Notes: Minor annual O&M to maintain pipeline servicing facility.

VOLUMETRIC CHARGE:

2013 dollars, $/mmbtu

Pricing Basis	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027

[TRADE SECRET DATA BEGINS… *…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
NET CAPACITY : Maximum Capacity	*[TRADE SECRET DATA BEGINS…*		*…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*

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]

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 Admi	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 Admi	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	Excelon	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			

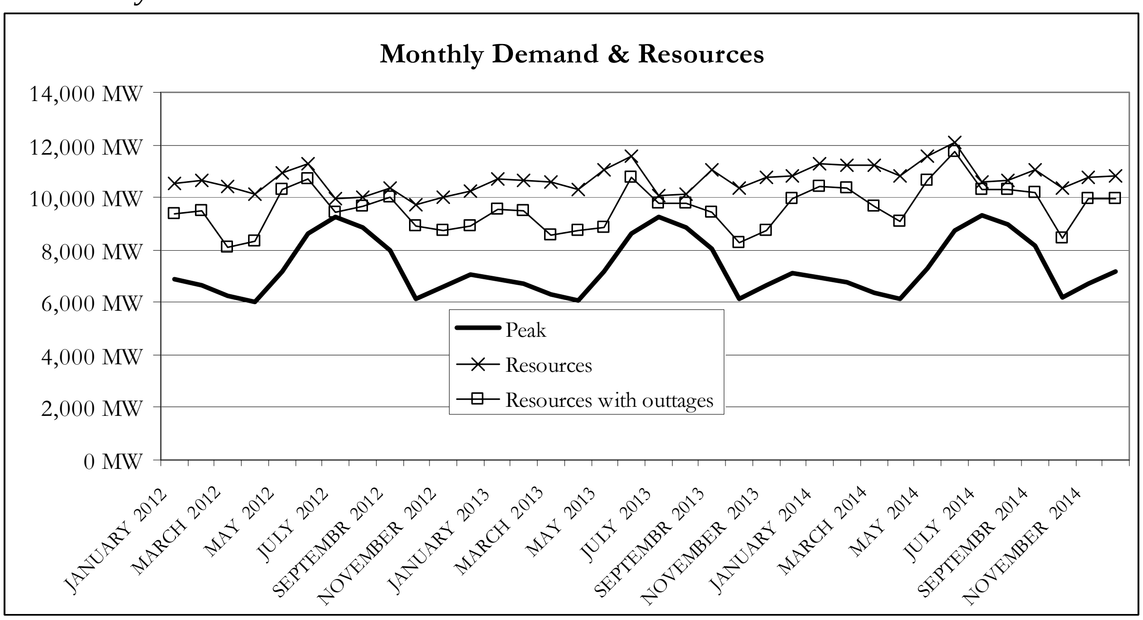
2021	2022	2023	2024	2025	2026
SolrRwds 1 MW	WIND 200MW	SolrRwds 1 MW	WIND 100MW	WIND 100MW	WIND 100MW
MH 5X16 122 MW	SolrRwds 1 MW		SolrRwds 1 MW	SolrRwds 1 MW	SolrRwds 1 MW
Generic CT 189 MW			Generic CT 189 MW	Generic CC 707 MW	
				Generic CT 189 MW	
				Generic CT 189 MW	

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 Dieristy -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.

ORDER

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

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[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.

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[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

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

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.

ORDER

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

Appendix F
Completeness Checklist

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

Appendix F
Completeness Checklist

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

Authority	Required Information	Location in Application
G.	Explanation of discrepancies between application's forecast and applicant forecasts in other proceedings;	Chapter 3 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
Completeness Checklist

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

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

Appendix F
Completeness Checklist

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	

Appendix F
Completeness Checklist

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:	

Appendix F
Completeness Checklist

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

Appendix F
Completeness Checklist

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

414 Nicollet Mall
Minneapolis, MN 55401

October 1, 2013

—Via Electronic Filing—

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: NOTICE OF CHANGED CIRCUMSTANCES
PROPOSAL TO ADD 750 MW OF WIND RESOURCES
DOCKET NOS. E002/M-12-1240 AND E002/RP-10-825

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission and parties to the above dockets, which include our most recent Resource Plan, this Notice of Changed Circumstances Affecting Resource Planning. At its September 4, 2013 Agenda meeting, the Commission determined that our recent proposal to add 750 MW of wind resources to our portfolio constitutes a changed circumstance under Minn. R. 7843.0500, subp. 5.[1] While requiring the Company to submit a changed circumstances filing in the above-referenced dockets, the Commission also determined that further administrative proceedings beyond those already in process are not necessary.

Therefore, we summarize our proposed resource acquisition below, and look forward to working with the Commission and other interested stakeholders in the established dockets to bring the benefits from the competitively-priced wind resources we have proposed to our customers.

We believe the wind generation market presented us with an unique opportunity to add generation that will keep energy prices lower for our customers than would otherwise be the case, and at the same time, will improve the environmental performance of our system with significant reductions in carbon dioxide emissions.

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[1] This rule requires utilities to inform the Commission and other parties to its last resource plan proceeding of changed circumstances that may significantly influence the selection of resource plans.

There are four wind projects that make-up the 750 MW of wind we have proposed to add to our system, as follows:[2]

- Two Power Purchase Agreements with Geronimo Energy:
  - (1) Courtenay (200 MW), located near Jamestown, North Dakota; and
  - (2) Odell (200 MW), located near Windom, Minnesota.

- Two Company-owned projects that RES America Developments, Inc. will develop and build, then transfer to Xcel Energy:
  - (1) Pleasant Valley project (200 MW), located near Austin, Minnesota; and
  - (2) Border Winds project (150 MW), located in Rolette County in north central North Dakota, near the Canadian border.

Consistent with our renewable energy strategy presented in our most recent Resource Plan, we had been monitoring the market for cost-effective opportunities to add renewable energy to our system. When January 2013 federal legislation extended the PTC to projects that have construction underway by the end of 2013, we expected that there may be opportunities to secure additional needed wind resources for our portfolio at cost effective prices. On February 4, 2013, we notified the Commission and interested stakeholders that we would be issuing an RFP for approximately 200 MW of wind generation. We issued our RFP on February 18, and received proposals with some of the lowest cost wind energy that we have acquired for some time.

Although we had indicated a target acquisition of 200 MW, we ultimately selected four projects totaling 750 MW. Our decision to pursue this much additional wind generation was based on the fact that: (1) we need significant wind resources for RES compliance over time; (2) the pricing is historically low and therefore, very attractive; and (3) our analysis indicated that the addition of these resources would provide both quantitative and qualitative benefits to our customers.

Our petitions seeking approval of the additions of these four wind projects are being considered in Docket No. E002/M-13-603 and E002/M-13-716.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list

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[2] *In the Matter of the Petition of Northern States Power Company for Approval of the Acquisition of 600 MW of Wind Generation*, July 16, 2013. (Docket No. E002/M-13-603) *In The Matter of the Petition of Northern States Power Company for Approval of the Acquisition of 150 MW of Wind Generation*, August 9, 2013. (Docket No. E002/M-13-716)

for Docket Nos. E002/RP-10-825 and E002/M-12-1240. 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
RATES AND REGULATORY AFFAIRS

Enclosure
c: Service Lists

CERTIFICATE OF SERVICE

I, SaGonna Thompson, hereby certify that I have this day served copies of the foregoing document or a summary thereof on the attached lists of persons:

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

xx via electronic filing

DOCKET NO. E002/RP-10-825
DOCKET NO. E002/CN-12-1240

Dated this 1st day of October, 2013

/s/
____
SaGonna Thompson

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OAH 8-2500-30760
MPUC Docket No. E-002 / CN-12-1240

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process

FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATION

On March 5, 2013, the Minnesota Public Utilities Commission (MPUC or Commission) concluded that Northern States Power Company d/b/a Xcel Energy (Xcel) had demonstrated the need for an additional 150 megawatts (MW) of electricity generation by 2017. The Commission further concluded that it was possible that this need could continue to increase to 500 MW by 2019.

Minn. Stat. § 216B.2422, subd. 5 authorizes the Commission to select the resources to meet such needs through a competitive procurement.

In this instance, because there were several different energy companies, including Xcel, that could meet the need for new generation, and a complex array of considerations between and among the competing proposals, the Commission set this matter on for a contested case hearing. It sought a report and recommendation from an Administrative Law Judge following a more complete development of the record. Specifically, the Commission directed that a contested case be undertaken to identify the resource proposal or proposals that will provide the most reasonable and prudent strategy for Xcel to meet the needs of its service area.

On October 21 and 22, 2013, Administrative Law Judge Eric L. Lipman presided over an evidentiary hearing on these issues. The following parties noted their appearance at the evidentiary hearing:

James R. Denniston, Assistant General Counsel, Northern States Power Company, and Michael C. Krikava, Thomas Erik Bailey and Kodi J. Church, Briggs and Morgan, appeared on behalf of Northern States Power Company (Xcel).

Michael J. Bradley, Moss & Barnett and Donna Stephenson, Associate Counsel, appeared on behalf of Great River Energy (GRE).

Kevin Reuther, Legal Director of the Minnesota Center for Environmental Advocacy (MCEA), appeared on behalf of MCEA, Fresh Energy, Sierra Club, and Izaak Walton League - Midwest Office (Environmental Intervenors).

Brian M. Meloy and Andrew J. Gibbons, Leonard, Street and Deinard, appeared on behalf of Calpine Corporation (Calpine).

Eric F. Swanson, Winthrop & Weinstine, appeared on behalf of Invenergy Thermal Development, LLC (Invenergy).

Christina K. Bruvsen, Fredrikson & Byron, appeared on behalf of Geronimo Wind Energy, LLC, d/b/a Geronimo Energy (Geronimo).

Ryan M. Norrell, Special Assistant Attorney General, appeared on behalf of the North Dakota Public Service Commission Advocacy Staff (Advocacy Staff).

Julia E. Anderson, Assistant Attorney General, appeared on behalf of the Minnesota Department of Commerce, Division of Energy Resources, Energy Regulation and Planning (DOC-DER or Department).

STATEMENT OF THE ISSUE

What resource proposals provide the most reasonable and prudent strategy for Xcel to meet the needs of its service area?

SUMMARY OF CONCLUSIONS

The Administrative Law Judge concludes that the most reasonable and prudent solution is to select scalable projects that meet Xcel's near-term shortfalls and for the Commission to conduct a second procurement for needs which may occur after 2019. The Administrative Law Judge further concludes that combining Geronimo's proposal with the GRE's proposal, represents the most reasonable and prudent alternative to meet Xcel's near-term needs.

Based upon the submissions of the parties and the contents of the hearing record, the Administrative Law Judge makes the following:

FINDINGS OF FACT

I. Plans and Forecasts Predating the Receipt of Proposals in this Docket

1. In August of 2010**,** Xcel filed a resource plan for the planning period of 2011 through 2025.[1]

2. Utilities in Minnesota file biennial resource plans with the Commission. These plans report upon the utility's: (1) projected energy needs over the next 15 years; (2) plans for meeting the projected need; (3) planning process for meeting the projected

[1] 2010 RESOURCE PLAN, *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, Docket No. E002/RP-10-825 (Aug. 2, 2010).

need; and (4) bases for selecting a specific resource mix proposed to meet the projected need.[2]

3. On March 15, 2011, in parallel filing with the Commission, Xcel sought a Certificate of Need for its Black Dog Generating Plant Repowering Project. In this submission, Xcel sought approval for the development of 450 megawatts (MW) of energy resources. These generation resources would address shortfalls in generation that Xcel projected would occur in 2014.[3]

4. In December of 2011, following a revision of its demand projections, Xcel proposed to cancel the Black Dog Generating Station project. It concluded that the demand for electricity would be lower than it earlier projected and thus this expansion project was not needed.[4]

5. In late October of 2012, Xcel likewise decided that it would not seek to increase the generating capacity of its Prairie Island Nuclear Generating Plant.[5]

6. In proceedings on its five-year action plan, Xcel reduced its estimates of future demand so as to "reflect, among other things, slower-than-projected economic growth, a loss of wholesale customers, changes in Xcel's wind procurement strategy, reassessments 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."[6]

7. Mindful of the change in the demand forecasts, the Commission directed Xcel to prepare a notice plan for soliciting proposals to meet the reduced needs in a competitive resource acquisition process. The Commission stated:

> [T]he 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

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[2] *See,* Minn. Stat. § 216B.2422 and Minn. R. 7843.0400.

[3] PETITION, *In the Matter of the Petition of Northern States Power Company for a Certificate of Need for the Black Dog Generating Plant Repowering Project,* Docket No. E002/CN-11-184 (Mar. 15, 2011).

[4] *In the Matter of the Petition of Northern States Power Company for a Certificate of Need for the Black Dog Generating Plant Repowering Project*, Docket No. E-002/CN-11-184, MOTION TO WITHDRAW APPLICATION AND REQUEST PURSUANT TO MINN. R. 1400.7600 FOR CERTIFICATION OF THIS MOTION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION (Dec. 7, 2011); *see also*, Hearing Transcript - Vol. 1 at 130 ("We've been working through our potential resource need in our resource plan docket and the outcome of that was the Commission's order identifying a resource need. At the same time, we initiated a proposal for a combined cycle unit at the Black Dog power plant site. As the great recession hit and our projected demand for electricity declined, we asked to withdraw that petition and ultimately the Commission concurred with that.").

[5] SUPPLEMENTAL FILING - NOTICE OF CHANGED CIRCUMSTANCES*, In the Matter of the Application of Northern States Power Company for a Certificate of Need for the Prairie Island Nuclear Generating Plant for an Extended Power Uprate*, Docket Nos. E002 / CN-08-509, E002 / RP-10-825, E002 / CN-11-184 (Oct. 22, 2012).

[6] *See,* ORDER ESTABLISHING RESOURCE ACQUISITION PROCESS, *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, Docket No. E-002/RP-10-825 at 6 (Nov. 30, 2012).

> 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[s], 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.[7]

8. The precise quantity of energy to be obtained through this process was not stated. Instead, the Commission identified a range of 150 MW in 2017, potentially increasing to 500 MW by 2019. Moreover, the Commission concluded that this description sufficed "to inform potential bidders of the scope of projects that the Commission will be considering."[8]

9. Because of a specialized statutory exemption, the project or projects selected in this Docket will not require a separate Certificate of Need.[9]

10. The Commission set a deadline of April 15, 2013 for submission of proposals to meet some, or all, of this need.[10]

11. On April 15, 2013, the Commission received proposals from Calpine, Geronimo, GRE, Invenergy and Xcel.[11]

II. Events that Followed the Receipt of Proposals which Impact the Forecasted Need for Energy

12. Following the receipt of proposals, there have been significant changes to Xcel's regulatory and operational environment.[12]

13. On May 21, 2013, the Legislature amended Minn. Stat. § 216B.1691, by adding a new subdivision. The amendment established a new solar energy mandate that obliges Xcel (and other utilities) to acquire 1.5 percent of its retail sales from solar energy by 2020. Moreover, these requirements are in addition to existing law which requires Xcel to provide 30 percent of its retail energy needs through renewable energy by the year 2020. The statute states:

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[7] *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, Docket No. E-002 / RP-10-825, ORDER APPROVING PLAN, FINDING NEED, ESTABLISHING FILING REQUIREMENTS AND CLOSING DOCKET at 2 and 6 (Mar. 5, 2013) (emphasis added); *see also,* Ex. 83 at 3 (Rakow Direct).

[8] *Id. at* 2 and 6.

[9] Minn. Stat. § 216B.2422, subd. 5 (b).

[10] NOTICE AND ORDER FOR HEARING, OAH 8-2500-30760 at 2 (June 21, 2013).

[11] *Id*.

[12] Ex. 49 at 2 (Alders Direct) (The "September 6 2013 Update of the Company's need indicates a capacity deficit of 93 MW in 2017, which grows to 307 MW by 2019. However, there are factors that create uncertainty and could materially affect our resource need assessment.").

Subd. 2f. Solar energy standard. (a) In addition to the requirements of subdivisions 2a and 2b, each public utility shall generate or procure sufficient electricity generated by solar energy to serve its retail electricity customers in Minnesota so that by the end of 2020, at least 1.5 percent of the utility's total retail electric sales to retail customers in Minnesota is generated by solar energy.[13]

14. In order to meet the requirement that an amount equal to 1.5 percent of its retail electric sales is drawn from solar energy resources, Xcel will require 455,919 MWh of solar energy resources by 2020.[14]

15. On July 16, 2013, Xcel filed a petition for approval of 600 MW of wind generation. Depending upon the availability of transmission upgrades, Xcel forecasted that these wind generation resources would be placed into service between 2017 and 2019.[15]

16. On August 9, 2013, Xcel filed a petition for approval of an additional 150 MW of wind generation. Xcel projected that these wind resources would be operational and available to Xcel by 2015.[16]

17. 750 MW of wind resources represents much larger acquisitions than Xcel had forecasted it would make in the near-term. Earlier in the year, Xcel projected that it would purchase 200 MW of energy from wind resources.[17]

18. On October 4, 2013, the Commission determined that Xcel's plans to acquire a total of 750 MW of wind generation constituted a changed circumstance to its resource plan. The Commission ordered Xcel to file a Notice of Changed Circumstances reflecting these changes.[18]

19. While this proceeding was underway, the Midcontinent Independent System Operator (MISO) sought a change in the way that "reserve margins" are calculated for electric utilities in the Midwest. "Reserve margins" are the amount of generation capacity that each utility must have in excess of their expected peak demand. These reserve resources can be called upon to maintain the electric grid's reliability in the event of unplanned outages of generation or transmission facilities.

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[13] Minn. Stat. § 216B.1691, subd. 2f; *see also,* 2013 Laws of Minnesota, Ch. 85, Art. 10, § 3; Minn. Stat. § 216B.1691, subd. 2a (b).

[14] Ex. 57 at 8 (Engelking Direct) (citing Xcel Energy Comments, *In the Matter of the Request for Filings From Electric Utilities on Customers Excluded From the Solar Energy Standard*, Docket No. E-999/CI-13-542 at 4 (August 15, 2013)).

[15] *In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of 600 MW of Wind Generation*, Docket No. E-002/M-13-603.

[16] *In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of 150 MW of Wind Generation*, Docket No. E-002/M-13-716.

[17] *See, e.g., Wind RFP Update*, Docket No. E-002/RP-10-825 at 1 (February 4, 2013).

[18] *Order Requiring Notice of Changed Circumstances and Granting Intervention,* Dockets E-002/RP-10-825, E-002/CN-12-1240, E-002/M-13-603, E-002/M-13-716 (October 4, 2013).

MISO establishes a new reserve margin percentage each year. MISO also establishes methods for calculating the available capacity of generation units in the region and applying these amounts to the needed reserve margin.[19]

20. In the past, MISO has calculated reserve margins so that they would be sufficient to meet MISO system peaks.[20]

21. Yet, the MISO system can, and frequently does, reach its system peak at a different hour than Xcel's system. Between 2006 and 2012, for example, customer demand on Xcel's system was 5 percent lower than during MISO's peak times.[21]

22. The change in MISO reserve margins became effective on October 30, 2013 and will be implemented for the 2014 - 2015 planning year.[22]

23. While many stakeholders have asked MISO to solidify its reserve margin methodology so that the reserve amounts do not vary widely from year-to-year, those longer-term planning metrics are not now in place. MISO has pledged that it will look into this issue in the coming months and hopes to provide updated long-term planning criteria by the fall of 2014.[23]

24. Calculating the minimum reserve capacity based upon the MISO system peak has a significant impact upon the amount of reserves Xcel must maintain in order to meet applicable reliability standards. The net impact of the methodology changes reduces Xcel's reserve requirements by approximately 200 MW.[24]

25. In recent weeks, Xcel has revised downward its projected energy needs. If the reserve requirements that are applicable today are included in a need forecast, alongside more recent load projections, there is no shortfall in capacity through 2018 and only 26 MW is needed by Xcel in 2019.[25]

26. In a November 4, 2013 filing with the Commission, Xcel projected that its actual sales would fall by .6 percent in 2014 and another .4 percent in 2015.[26]

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[19] Ex. 46 at 5-6 (Wishart Direct); Ex. 83 at 20 n.8 (Rakow Direct).

[20] Ex. 83 at 22-24 (Rakow Direct).

[21] Ex. 46 at 8-9 and Table 3 (Wishart Direct).

[22] Midcontinent Indep. Sys. Operator, Inc., 145 FERC 61,077 (Oct. 29, 2013) (order conditionally accepting filing in Docket No. ER 13-2298-000).

[23] Ex. 46 at 10 (Wishart Direct); *see also*, Ex. 49 at 8 (Alders Direct) ("the Midcontinent Independent System Operator's resource adequacy process is in flux").

[24] Ex. 46 at 10 (Wishart Direct).

[25] *Id. at* 7 - 10 (Wishart Direct).

[26] *See, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002 / GR-13-868, Direct Testimony of Jannell E. Marks at 5 (Nov. 4, 2013).

27. Dr. Rakow and the Department express a different view. They assert that Minnesota's economy is improving and that demand for electricity will increase as the economy improves.[27]

28. The Department likewise asserts that only Xcel's Fall 2011 forecast, and not its most-recent estimates, has been approved by the Commission. It states further that it has not verified the accuracy of Xcel's spring 2013 sales forecast, nor relied upon its projections in this proceeding.[28]

29. Given the uncertainty surrounding its resource needs, the regulatory requirements that it will be required to meet in the near-term, and the direction of the state's economy, Xcel recommends that the Commission authorize contract options that permit it to postpone the service dates of any projects that are selected in this proceeding, and perhaps, cancel those projects altogether.[29]

30. The Department joins Xcel in this recommendation, noting that delayed in-service dates for projects could result in substantial cost savings.[30]

31. It is Xcel's expectation that if any offeror selected in this process incurs expenses in order to meet an in-service date specified in a Purchase Power Agreement, those expenses would be recoverable from ratepayers in the event that the project is later cancelled.[31]

III. Procedural Practice in the Contested Case

32. On June 3, 2013 – after the April 15, 2013 deadline for submission of proposals – Ecos Energy, LLC (Ecos Energy) petitioned the Commission for leave to submit a generation proposal.[32]

33. On June 6, 2013, the Commission met to consider the matter of Xcel's resource acquisition process.[33]

34. In the Commission's June 21, 2013 *Notice and Order for Hearing,* the Commission referred this matter to the Office of Administrative Hearings for a contested case proceeding. The Commission also:

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[27] Ex. 83 at 41 (Rakow Direct).

[28] Hearing Transcript - Vol. 2 at 29-30.

[29] Ex. 46 at 2 and 11 (Wishart Direct); Ex. 49 at 8 (Alders Direct); Hearing Transcript - Vol. 1 at 125, 134 and 140.

[30] *See,* Hearing Transcript, Vol. 2 at 55.

[31] Hearing Transcript, Vol. 1 at 126-27.

[32] NOTICE AND ORDER FOR HEARING, OAH 8-2500-30760 at 2 (June 21, 2013).

[33] *Id*.

(A) Denied the request of Ecos Energy for permission to submit a generation proposal.

(B) Determined that the developer of a project chosen through this Commission-approved competitive resource acquisition process is exempt from securing a certificate of need under Minn. Stat. § 216B.243 prior to construction.

(C) Found that the proposals filed by Calpine, Geronimo, GRE, Invenergy and Xcel were substantially complete.

(D) Directed that an Environmental Report be prepared by the Department of Commerce, Energy Environmental Review and Analysis (EERA) for the Commission and:

(1) Authorized EERA to focus its analysis on the substantially complete alternatives, and on a no-build alternative for each of these alternatives;

(2) Requested that EERA prepare an Environmental Report sufficient to meet the requirements set forth in Minn. R. 7849, as varied, for all of the substantially complete alternatives;

(3) Requested that EERA review Geronimo's Solar Proposal cumulatively for the up to 31 sites; and

(4) Requested that EERA treat the GRE capacity credit proposal as capacity only.

(E) Designated the following entities as parties to the contested case proceeding: Calpine, Geronimo, GRE, Invenergy, Xcel, the Department and the Environmental Intervenors.[34]

35. The Administrative Law Judge convened a prehearing conference on July 1, 2013 and established a schedule for further proceedings.[35]

36. Ecos Energy filed a Petition to Intervene on June 7, 2013.[36]

37. Ecos Energy filed a Verified Petition to Intervene, on July 10, 2013.[37]

[34] *Id.* at 4.

[35] SECOND PREHEARING ORDER, OAH 8-2500-30760 (July 17, 2013).

[36] eDocket No. 20136-87947-01.

[37] eDocket No. 20137-88996-01.

38. The North Dakota Public Service Commission Advocacy Staff filed a Petition to Intervene on July 31, 2013.[38]

39. On August 5, 2013, the Commission denied the reconsideration motion of Ecos Energy to submit a proposal out of time.[39]

40. On August 21, 2013, having considered objections, the Administrative Law Judge denied the Petition to Intervene from Ecos Energy and granted the Petition to Intervene from the North Dakota Advocacy Staff.[40]

41. On September 5, 2013, Ecos Energy sought Reconsideration, or in the alternative, Certification of, its Petition to Intervene.[41]

42. On September 27, 2013, the following parties filed Direct Testimony: Calpine, Geronimo, GRE, Invenergy, Xcel, North Dakota Advocacy Staff and the Department.[42]

43. On October 1, 2013, having considered objections, the Administrative Law Judge denied Ecos Energy's Motion for Reconsideration and its alternative Motion for Certification.[43]

44. On October 8, 2013, the Xcel Large Industrials (XLI) filed a Petition to Intervene.[44]

45. On October 10, 2013, the Administrative Law Judge set the evidentiary hearing to begin on Tuesday, October 22, 2013.[45]

46. On October 14, 2013, EERA issued the Environmental Report.[46]

47. On October 15, 2013, the Honorable Steve M. Mihalchick presided over a public hearing at the State Office Building in St. Paul, Minnesota.[47]

48. On October 18, 2013, the following parties filed Rebuttal Testimony: Calpine, Geronimo, GRE, Invenergy, Xcel, and the Department.[48]

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[38] eDocket No. 20138-89905-01.

[39] ORDER DENYING INTERVENTION, OAH 8-2500-30760 (August 5, 2013).

[40] THIRD PREHEARING ORDER, OAH 8-2500-30760 (August 21, 2013).

[41] eDocket No. 20139-90988-01.

[42] *See generally,* MPUC Docket No. 12-1240 (September 27, 2013).

[43] FOURTH PREHEARING ORDER, OAH 8-2500-30760 (October 1, 2013).

[44] eDocket No. 201310-92220-01.

[45] AMENDED SEVENTH PREHEARING ORDER, OAH 8-2500-30760 (October 10, 2013).

[46] Ex. 38.

[47] eDocket No. 201311-93216-01.

[48] *See generally,* MPUC Docket No. 12-1240 (October 18, 2013).

49. On October 21, 2013, the Administrative Law Judge: (1) denied XLI's Petition to Intervene; (2) extended the public comment period by 21 days to match the deadline for the submission of initial briefs from the parties; and (3) invited both XLI and Ecos Energy to submit briefs as *amicus curiae* by the close of the extended deadline.[49]

50. On October 22 and 23, 2013, the Administrative Law Judge convened an evidentiary hearing at the State Office Building in St. Paul, Minnesota.[50]

51. On November 22, 2013, the public comment period closed. Approximately 60 public comments were filed with the Commission, including 17 from local government representatives, 30 from local landowners and individuals, 11 from organizations and companies and 2 from federal and state government agencies representatives.[51]

52. On November 22, 2013, Calpine, Geronimo, GRE, Invenergy, Xcel, the Department and the Environmental Intervenors filed initial briefs.[52]

53. The hearing record closed at 4:30 p.m. on Friday, December 6, 2013, following receipt of the parties' reply briefs.[53]

IV. Overview of the Proposals

54. The Commission accepted proposals from five offerors:

(1) Xcel's 215 MW Black Dog 6 combustion turbine peaking facility and two 215 MW combustion turbine Red River Valley Units 1 and 2;

(2) Calpine's 345 MW combined cycle turbine intermediate facility at Mankato;

(3) Geronimo Energy's 100 MW distributed solar capacity intermittent resource;

(4) GRE's proposed sale of capacity credits; and,

(5) Invenergy, with a 179 MW combustion turbine peaking facility at Cannon Falls and two 179 combustion turbines at Hampton.[54]

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[49] *See,* EIGHTH PREHEARING ORDER, OAH 8-2500-30760 (October 21, 2013).

[50] Hearing Transcripts, Volumes 1 and 2 (October 22 and 23, 2013).

[51] *See,* eDocket No. 201311-94078-01.

[52] *See generally,* MPUC Docket No. 12-1240 (November 22, 2013).

[53] *See generally,* MPUC Docket No. 12-1240 (December 6, 2013).

[54] NOTICE AND ORDER FOR HEARING, OAH 8-2500-30760 at 9 (Jun. 21, 2013).

55. Because three of the offerors proposed projects utilizing gas-fired turbines, James Alders, Xcel's Rates and Regulatory Affairs Consultant, noted the differences between combined cycle and combustion turbines:

> It's a large combustion turbine fired with natural gas. Peaking units tend to operate very few hours during the year, only when the demand for electricity is at its highest in the summer. The proposal by Calpine, and they can speak to this in more detail, is called a combined cycling unit, and it is a combustion turbine where the flue gas from that combustion turbine then is used to heat water and create steam in a second cycle to produce more electricity. The economics of those sorts of facilities are such that they're often used more often during the year in an intermediate role in our system.[55]

V. Features of the Proposal Submitted by Xcel

56. Xcel proposed to construct three natural-gas-fired, simple-cycle, 215 megawatt (MW) combustion turbine generators sequentially to match the identified need.[56]

57. The first combustion turbine unit would be located at Xcel's Black Dog generating plant in Burnsville, Minnesota. Xcel likewise proposes a flexible in-service date of 2017, 2018 or 2019.[57]

58. This unit would substantially replace the coal-fired generating capacity at the Black Dog site.[58]

59. Xcel's Black Dog 6 project would be built in the existing powerhouse at the Black Dog site, in the area where Unit 4 is currently located. This siting would allow Xcel to maximize the use of existing infrastructure and maintain generation within its largest load center.[59]

60. The exhaust stack would be approximately 200 feet tall and would be located adjacent to the unit, in the area of the existing Unit 4 boiler.[60]

61. Unit 6 would be connected to the existing 115 kV switchyard and transmission system. For this reason, no upgrades to the existing 115 kV transmission system would be required to bring Unit 6 into service.[61]

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[55] Public Hearing Transcript, Vol. 1 at 11-12.

[56] Ex. 1 at 1-1 and 1-2 (Xcel Energy Proposal).

[57] Ex. 1 at 1-3 to 1-4 (Xcel Energy Proposal); Ex. 46 at 11 (Wishart Direct); Ex. 49 at 2 (Alders Direct).

[58] Ex. 1 at 1-1 (Xcel Energy Proposal).

[59] Ex. 1 at 1-11 (Xcel Energy Proposal).

[60] *Id*.

[61] *Id*.

62. The unit would be fueled entirely by natural gas. CenterPoint Energy currently serves the plant site. Xcel proposes to secure additional natural gas supply through a competitive process. Xcel anticipates that the winning vendor may need to replace the existing pipeline serving the plant with a new higher pressure natural gas line from the Cedar Town Border station.[62]

63. Xcel proposes a Model F combustion turbine. This combustion turbine can generate 150 MW within ten minutes of a "cold start," and operates in a range between 50 to 100 percent load while meeting emission limits. The unit has faster ramp rates over the load range. During summer heat and humidity conditions, the maximum output of the unit is approximately 215 MW.[63]

64. The Black Dog plant is located on a 35-acre parcel. The plant site is well-buffered within a still larger 1,900-acre area owned by Xcel.[64]

65. The output of Black Dog Unit 6 depends upon ambient weather conditions (primarily temperature and humidity) and altitude. Nominal generating capacity will be approximately 215 MW at summer ambient conditions of 95 degrees Fahrenheit and relative humidity of 30 percent, with an altitude of 720 feet above sea level.[65]

66. Black Dog 6 would operate as a peaking generator, with an anticipated annual capacity factor of four to ten percent. The annual availability of Black Dog 6 would be greater than 95 percent, and its service life is expected to exceed 35 years.[66]

67. Xcel proposes to construct Unit 6 in 2016 and 2017. Under its proposal, decommissioning, demolition and removal of the existing Unit 4 turbine, generator, boiler and related equipment would begin in the fall of 2014.[67]

68. Xcel anticipates that the construction of its Black Dog combustion turbine unit would require 21 months.[68]

69. Xcel's proposed Red River Valley Units 1 and 2 would be located near the community of Hankinson, North Dakota, near the existing 230 kV transmission system and major natural gas pipeline routes. This plant would utilize less than 35 acres of a larger 160-acre parcel that Xcel plans to acquire. The undeveloped portions of the site would buffer the plant from surrounding uses. The Hankinson site is located within a rural setting with low residential densities.[69]

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[62] Ex. 1 at 1-11 (Xcel Energy Proposal).

[63] Ex. 1 at 1-10 (Xcel Energy Proposal).

[64] Ex. 1 at 1-13 (Xcel Energy Proposal).

[65] Ex. 1 at 4-6 (Xcel Energy Proposal).

[66] Ex. 42 at 3 (Ford Direct).

[67] Ex. 1 at 1-11 (Xcel Energy Proposal).

[68] Ex. 38 at 6 (Environmental Report).

[69] Ex. 1 at 1-11, 1-12 and 1-13 (Xcel Energy Proposal).

70. Xcel proposes to place the Red River Valley Unit 1 combustion turbine and associated natural gas, transmission, and interconnection facilities into service in 2018. It proposes to add Red River Valley Unit 2 to the plant site after the first Red River Valley combustion turbine and place this second unit into service in 2019.[70]

71. Alternatively, Xcel asserts that it could deploy the Red River Valley turbines together in either 2018 or 2019. It notes that this later, simultaneous deployment could result in economies of scale and cost savings.[71]

72. The tallest structure on the Red River site would be the stack, standing at approximately 65 feet tall. Xcel projects that the tanks, combustion turbine, and maintenance and operations building will be less than 40 feet in height.[72]

73. The combustion turbine facility would utilize natural gas. A short gas pipeline would be necessary to connect the plant to the fuel supplier.[73]

74. Xcel's assessment is that the Alliance pipeline has adequate capacity to serve Red River Valley units, and that the fuel would be available with high reliability.[74]

75. Red River Valley Units 1 and 2 would connect to a new 230 kV substation with a short double circuit 230 kV line. The system interconnection will require an upgrade of the existing Hankinson – Wahpeton 230 kV line.[75]

76. Xcel likewise proposes Model F combustion turbines for the Red River Valley Units.[76]

77. The units would be integrated into Xcel's remote dispatch control center. Xcel would use the units for peaking service, dispatching them after all incrementally lower-cost units. The units would be primarily dispatched during higher system load periods in the summer and winter months, during peak demand period, with annual capacity factors between four and ten percent.[77]

78. The output of the Red River Units depends upon ambient weather conditions. Nominal generating capacity is considered about 214 MW at summer ambient conditions of 88 degrees Fahrenheit and relative humidity of 42 percent with an altitude of 900 feet above sea level.[78]

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[70] Ex. 1 at 1-2 (Xcel Energy Proposal).

[71] Ex. 1 at 1-2 and 1-12 (Xcel Energy Proposal).

[72] Ex. 1 at 1-12 (Xcel Energy Proposal).

[73] *Id*.

[74] Ex. 46 at 13 (Wishart Direct).

[75] Ex. 1 at 1-12 and 4-11 (Xcel Energy Proposal).

[76] Ex. 1 at 1-10 (Xcel Energy Proposal).

[77] Ex. 1 at 1-12 (Xcel Energy Proposal).

[78] Ex. 1 at 4-9 (Xcel Energy Proposal).

79. The combustion turbines would utilize natural gas as their fuel. The facility allows for the addition of distillate oil storage and handling if a future need develops to have oil as the backup fuel. Xcel anticipates securing the necessary natural gas supply through a competitive process beginning in 2014.[79]

80. Xcel plans to obtain the water that is needed for the Red River units from either an on-site well or truck shipments.[80]

81. The Red River Valley Units would place generation closer to Xcel's Fargo load center, and would moderate Xcel's reliance on the high voltage transmission system to deliver energy to this part of its system.[81]

82. Xcel proposed the establishment of a rider similar to one that the Commission approved for the Minnesota Metro Emissions Reduction Project (MERP). It proposed that a rate rider be established for each unit in its proposal that is selected by the Commission. Xcel further proposed that each unit's return on equity (ROE) be adjusted – either upwards or downwards – to reflect any difference between the estimated capital cost and the actual cost of constructing the unit. The rider, with adjusted ROE, would be used during the first five years of rate recovery. After that time, Xcel proposed that the last authorized ROE would be used until the projects are included in base rates. Xcel also proposed different adjustments to the Company's ROE based upon the percentage difference of actual costs compared to estimated costs used to evaluate Xcel's proposal.[82]

VI. Features of the Proposal Submitted by Calpine

83. Calpine proposed to construct a 345 MW combined cycle gas plant at its existing Mankato Energy Center (the "Mankato facility") to match the identified need.[83]

84. Calpine proposed to supply 345 MW of the estimated 500 MW of Xcel's forecasted energy needs. Calpine proposes to expand its Mankato Energy Center in the city of Mankato, Minnesota, through the addition of one natural-gas-fired combustion turbine generator, an additional heat recovery steam generator, and related ancillary equipment.[84]

85. The Mankato Expansion would increase the Center's energy output by adding 290 MW of intermediate combined-cycle capacity and 55 MW of peaking capacity.[85]

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[79] Ex. 1 at 4-9 (Xcel Energy Proposal).

[80] *Id*.

[81] Ex. 42 at 4 (Ford Direct).

[82] Ex. 49 at 1, 2 and 5 (Alders Direct); Hearing Transcript, Vol. 1 at 136-137.

[83] *See* Ex. 8 (Calpine's Proposal).

[84] Ex. 8 at 2 (Calpine's Proposal).

[85] *Id*.

86. The existing Mankato Energy Center consists of a 375 MW natural gas fired, combined cycle plant with one Siemens 501FD combustion turbine generator, one Nooter/Erikson heat recovery steam generator, a Toshiba TCDF 40L steam turbine generator, and other ancillary equipment.[86]

87. The Mankato Expansion would complete a two-phase project – that was earlier approved by the Commission – for a 720 MW power plant. The first phase of this project was placed into service in 2006. The proposed expansion would be the second phase and completion of the originally-designed project.[87]

88. Because the project would be located entirely on the Mankato Energy Center's existing 25-acre site, it utilizes a brownfield that is now used for electric power generation.[88]

89. Natural gas is provided to the Mankato Energy Center through a 20-inch gas pipeline that interconnects with Northern Natural Gas' interstate pipeline facilities. This existing pipeline lateral is sufficiently sized to accommodate the future requirements of this expansion. The project would also use the existing plant's transmission outlets and interconnections to Xcel's Mankato substation. The existing plant switchyard and adjacent substation are appropriately sized for the incremental plant output.[89]

90. The Mankato Energy Center uses treated wastewater for processing and cooling. Discharges of water from the plant are routed to the city of Mankato's treatment plant. This allows the city of Mankato to manage more effectively the quality of its water discharge.[90]

91. The Mankato Expansion has strong local support and would provide both near-term and long-term local economic benefits through construction jobs, tax revenues to the city of Mankato, and revenues for the city of Mankato water department.[91]

92. Combined cycle plants are typically defined as intermediate generation which has higher expected annual capacity factors. These types of units are more efficient than peaking facilities, but generally have higher construction, operation and maintenance costs.[92]

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[86] Ex. 55 at 6 (Thornton Direct).

[87] Ex. 8 at 3 (Calpine's Proposal).

[88] Ex. 8 at 6 (Calpine's Proposal); Ex. 55 at 8 (Thornton Direct).

[89] Ex. 55 at 8-9 (Thornton Direct).

[90] Ex. 8 at 6 (Calpine's Proposal).

[91] Ex. 8 at 6 (Calpine's Proposal).

[92] Ex. 46 at 16 (Wishart Direct).

93. The Mankato facility's combined cycle unit would operate as an intermediate type resource with capacity factors in the 20 to 30 percent range.[93]

94. By utilizing existing gas, generating and transmission infrastructure, Calpine asserts that the Mankato Expansion avoids proliferation of generating sites and transmission corridors.[94]

95. The combined cycle power plant provides comparatively "fast start" capabilities and "start-stop" scheduling flexibility.[95]

96. Calpine asserts that these features make a combined cycle resource the most appropriate addition to Xcel's growing portfolio of intermittent power resources.[96]

97. Calpine projects that it could place the Mankato Expansion into service by June 1, 2017.[97]

VII. Features of the Proposal Submitted by Geronimo

98. Geronimo proposes to develop 130 MW of direct current (DC) nameplate capacity – equivalent to 100 MW of alternating current – of distributed solar energy from within Xcel's Upper Midwest service territory.[98]

99. The project consists of distributed photovoltaic power plants that would be located at approximately 20 sites serving Xcel loads within MISO Planning Resource Zone 1.[99]

100. The distributed solar facilities range in size from 2 MW to 10 MW and would utilize a linear axis tracker to increase the accredited capacity of the systems. The tracking system adjusts the tilt of each array such that the rays of sun remain perpendicular to the solar panels in at least one dimension throughout the day. With these additions the accreditation of the unit rises to 71.20 percent.[100]

101. Geronimo sized the solar facilities to offset approximately 20 percent of the existing load at each respective substation. Further, by locating the solar facilities in close proximity to existing substations, the project would be able to make efficient use of

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[93] Ex. 46 at 17 (Wishart Direct).

[94] Ex. 8 at 6 (Calpine's Proposal).

[95] Ex. 8 - Appendix A at 2; Ex. 55 at 11 (Thornton Direct).

[96] *See,* Ex. 55 at 2 (Thornton Direct).

[97] Ex. 8 at 4 (Calpine's Proposal).

[98] Ex. 13 at 1 (Geronimo Proposal); Ex. 57 at 3 (Engelking Direct); Ex. 61 at 3 (Beach Rebuttal).

[99] Ex. 13 at 12 (Geronimo Proposal); Ex. 57 at 3 (Engelking Direct); Ex. 62 at 6-7 (Skarbakka Direct).

[100] Ex. 13 at 4 (Geronimo Proposal); Ex. 57 at 3 (Engelking Direct).

existing transmission facilities. Each substation zone ranges in size from 20 to 70 acres and include design features which limit environmental impacts.[101]

102. Geronimo asserts that distributed solar facilities greatly reduce the impact of individual transmission equipment failures and limitations. Outages of individual transmission lines, distribution lines, or a solar facility component will, in nearly all cases, reduce the output from only a single solar facility. In such circumstances, the remainder of the project continues to be operational.[102]

103. Similarly, disbursement of Geronimo's units increases the reliability, and reduces the variability of, energy output from the proposed project.[103]

104. The project would generate energy without significant air emissions.[104]

105. The solar project has no associated fuel costs, and, therefore, provides for a fixed and certain price for the life of the project.[105]

106. Geronimo's facilities can be interconnected at the distribution system, allowing for fewer line losses and greater reliability.[106]

107. The project's estimated average annual availability is in excess of 97 percent. The expected service life of the proposed facilities is 25 to 40 years. The minimum specifications for the solar module production warranty are 90 percent of nameplate capacity at year 10 and 80 percent of nameplate capacity at year 25.[107]

108. As a non-wind variable generation resource, the proposal would provide Xcel with 71 MW of accredited capacity to meet its peak capacity obligation in the MISO Planning Reserve Sharing Pool and up to 200,000 MWh of primarily on-peak energy each year.[108]

109. The project would also provide Renewable Energy Credits (RECs) that Xcel can use to meet Renewable Energy Standards or a specific solar requirement in the states it serves.[109]

110. Geronimo has proposed an in-service date of December 2016 so as to meet Xcel's energy needs between 2017 and 2019.[110]

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[101] Ex. 13 at 4 (Geronimo Proposal).

[102] Ex. 13 at 26 (Geronimo Proposal); Ex. 60 at 5 (Beach Direct); Ex. 62 at 4 (Skarbakka Direct).

[103] *Id*.

[104] Ex. 13 at 24 (Geronimo Proposal); Ex. 57 at 5 (Engelking Direct).

[105] Ex. 13 at 19 (Geronimo Proposal); Ex. 57 at 5 (Engelking Direct).

[106] Ex. 57 at 5 (Engelking Direct).

[107] Ex. 13 at 16 (Geronimo Proposal).

[108] Ex. 13 at 1 (Geronimo Proposal); Ex. 57 at 2 (Engelking Direct).

[109] Ex. 13 at 1 (Geronimo Proposal).

[110] Ex. 13 at 26 (Geronimo Proposal); Ex. 57 at 3 (Engelking Direct).

111. Xcel estimated that the Geronimo project would fulfill approximately one-third of Xcel's solar energy requirements – namely, to provide 1.5 percent of its retail sales from solar energy sources – four years before the 2020 compliance date.[111]

112. Xcel could likewise market the Solar Renewable Energy Credits (S-RECs) to other utilities that need to meet solar-specific requirements in other states.[112]

113. The project's primary components are a nominal 300 watt photovoltaic module mounted on a linear axis tracking system and a centralized inverter(s).[113]

114. The tracking system foundations would utilize a driver pier and do not require concrete. The remainder of the plants includes electrical cables, conduit, step up transformers and metering equipment. The solar facilities would be fenced and seeded in a low growth seed mix to reduce run-off and improve water quality.[114]

115. Geronimo submitted two different pricing proposals. The first includes a fixed monthly payment per kilowatt (kW) for capacity and an energy payment for all energy generated by the project. The second pricing proposal is an energy-only payment that bundles all capacity, energy and environmental attributes into a dollars per megawatt hour price.[115]

116. Geronimo's proposed Purchase Power Agreement has a defined price over its twenty-year term.[116]

117. Under both pricing scenarios, Geronimo bears all of the interconnection and network upgrade costs associated with the project.[117]

VIII. Features of the Proposal Submitted by Great River Energy

118. Great River Energy's proposal offered accredited capacity from its generation assets to meet a portion of Xcel's need.[118]

119. Great River Energy proposes to sell Xcel MISO Zone 1 Resource Credits within the 2017 - 2019 timeframe. Additionally, GRE signaled its willingness to make a sale of credits in any or all of the three years covered by its proposal.[119]

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[111] Ex. 46 at 18 (Wishart Direct).

[112] Ex. 13 at 1 (Geronimo Proposal).

[113] Ex. 13 at 4 (Geronimo Proposal).

[114] *Id*.

[115] Ex. 57 at 5 (Engelking Direct).

[116] Ex. 13 at 19 (Distributed Solar Energy Proposal).

[117] Ex. 62 at 10-11 (Skarbakka Direct).

[118] Ex. 19 at 1 (GRE Proposal); Ex. 63 at 2-3 (Selander Direct).

[119] Ex. 19 at 1 (GRE Proposal); Ex. 64 at 3 (Selander Rebuttal).

120. GRE's generators are dispatched by MISO. The operation of these generators is not dependent upon the outcome in this Docket.[120]

121. This proposal could provide an alternative to building new generation resources in the near-term.[121]

122. A sale of existing credits results in no net increase in overall emission levels, externality costs or incremental environmental impacts associated with GRE's proposal.[122]

IX. Features of the Proposal Submitted by Invenergy

123. Invenergy proposes three 179 MW combustion turbine natural gas plants, including a 179 MW plant in Cannon Falls, MN, and two 179 MW plants near Hampton in Dakota County, Minnesota (the "Hampton Energy Center").[123]

124. Invenergy's Cannon Falls Energy Center commenced commercial operations in 2008. The Center consists of two simple cycle, dual fuel General Electric 7FA combustion turbines, providing 357 MW of peaking capacity. It receives natural gas through Greater Minnesota Transmission and Northern Natural Gas. Xcel purchases the output of the project under a long-term power purchase agreement reviewed and approved by this Commission.[124]

125. The Cannon Falls Energy Center has had a 96.9 percent Capacity Availability Factor over the last two years. After adjusting for planned outages, the Cannon Falls facility has shown a reliability of 99.2 percent since the 2008 commercial operation date.[125]

126. The proposed Expansion can be operational as early as January 1, 2016, with commercial operation beginning June 1, 2016, if needed, to meet Xcel's needs.[126]

127. Invenergy proposes to locate the Expansion on 9.3 acres of vacant land that is directly north of the existing Cannon Falls units in an area that is zoned for industrial uses.[127]

128. The Expansion would have minimal impacts to the surrounding area.[128]

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[120] Ex. 63 at 3 (Selander Direct); Ex. 64 at 4 (Selander Rebuttal).

[121] Ex. 19 at 1 (GRE Proposal).

[122] Ex. 38 at 12 and 57 (Environmental Report); Ex. 64 at 4-6 (Selander Rebuttal).

[123] Ex. 70 at 12 (Shield Direct).

[124] Ex. 24 at 7, 11 and 17 (Invenergy Proposal).

[125] Ex. 70 at 12 (Shield Direct).

[126] Ex. 70 - Attachment 1 at 4 and 8 (Shield Direct).

[127] Ex. 65 at 17 (Ewan Direct).

[128] Ex. 38 at 23 and 58 (DOC EERA Environmental Report); Ex. 65 at 18-19 (Ewan Direct).

129. The Expansion will require water for evaporative cooling on hot summer days and for emission controls when firing back-up fuel. The needed water resources can be supplied through the existing infrastructure. No surface water will be used as part of energy generation.[129]

130. As a peaking facility, the Expansion will operate a limited number of hours each year.[130]

131. Invenergy also proposes to develop the Hampton Energy Center in Dakota County, Minnesota, with the addition of two simple cycle, General Electric 7FA combustion turbine generators.[131]

132. The Hampton site is located approximately 20 miles southeast of the Minneapolis – St. Paul metropolitan area. The southeast area does not now have other Xcel generation resources nearby.[132]

133. The Hampton Energy Center would be installed on a 20-acre parcel north of Hampton, Minnesota. The parcel is located on 215th Street one quarter mile west of State Highway 52. This portion of Dakota County is a rural setting. There are four residences within one half mile of the proposed site.[133]

134. The site is adjacent to a new 345 kV electrical substation that is under construction. The proposed project would interconnect with the new substation.[134]

135. The tallest structure at the facility would be approximately 75 feet above grade. Invenergy proposes berms and landscaping to minimize visual impacts of the site's features.[135]

136. The Hampton proposal includes fuel oil as a back-up fuel. Invenergy proposes to include a 750,000 gallon fuel oil storage tank or similar design as the tank.[136]

137. The facility would require water for evaporative cooling on hot summery days and for emission controls when firing the back-up fuel. Two industrial wells would be drilled to supply the anticipated water needs for the facility. Any needed water

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[129] Ex. 65 at 17 (Ewan Direct); Ex. 38 at 17-18 (DOC EERA Environmental Report).

[130] Ex. 38 at 37 (DOC EERA Environmental Report).

[131] Ex. 26 at 4 (Invenergy Hampton Proposal).

[132] *Id.*; Ex. 65 at 3 (Ewan Direct).

[133] Ex. 65 at 19-20 (Ewan Direct).

[134] *Id.*

[135] *Id.* at 19 (Ewan Direct).

[136] *Id.* at 7 (Ewan Direct).

treatment would be accomplished with temporary trailer base demineralizers or onsite equipment.[137]

138. The proposed combustion turbine could achieve minimum load within approximately 20 minutes of a "cold start" and full load within 30 minutes of such a start. Invenergy asserts that these features make its combustion cycle resource an appropriate addition to Xcel's growing portfolio of intermittent power resources.[138]

139. Invenergy's proposal did not separately price additional transmission facilities that may be needed.[139]

140. The project would be interconnected to an existing natural gas pipeline of Greater Minnesota Gas, Inc., that runs less than one half mile from the proposed project site.[140]

141. Invenergy proposes to minimize the emissions from its facility through the use of dry low NOx burners, a water injection system to minimize NOx emissions when fuel oil is used and strict limitations on the use of the unit that operates on fuel oil.[141]

142. The project capacity would range from approximately 310 MW in the summer to 380 MW in the winter. Actual available capacity would be determined by temperature and relative humidity. The project would have a Net Capability of 357 MW at the point of interconnection.[142]

143. The project is scheduled to be in operation as early as January 1, 2016, but no later than January 1, 2017.[143]

144. Invenergy offered identical pricing for either a June 1, 2016 or a June 1, 2017 commercial operation date, thereby providing additional flexibility to Xcel. In addition, Invenergy offered in-service dates of June 1, 2018 and June 1, 2019.[144]

145. For the Expansion, Invenergy offered to enter into a fixed price PPA to be executed and in which Invenergy assumes the construction and operation cost risk associated with the Expansion.[145]

146. In response to Xcel's inclusion of a "replacement cost" assumption in its analysis of the Expansion, Invenergy also offered an additional power purchase

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[137] *Id.* at 19 (Ewan Direct).

[138] Ex. 65 at 7-8 (Ewan Direct).

[139] *See,* Ex. 26 at 4 (Invenergy Hampton Proposal); Ex. 46 at 15 (Wishart Direct).

[140] Ex. 26 at 4-5 (Invenergy Hampton Proposal).

[141] Ex. 65 at 20 (Ewan Direct).

[142] Ex. 26 at 8-9 (Invenergy Hampton Proposal).

[143] Ex. 26 at 4 (Invenergy Hampton Proposal).

[144] Ex. 69 at 4 (Ewan Rebuttal); Trade Secret Ex. 87 attachment SR-R-9 at 3-4 (Rakow Rebuttal).

[145] *See*, Ex. 65 at 32 (Ewan Direct).

agreement term giving Xcel the option to extend the PPA in five year increments at a reduced capacity price for up to three additional five year terms.[146]

147. Invenergy also offered in-service dates of June 1, 2018 and June 1, 2019 for the Hampton facilties. Further, as with its Expansion proposal, Invenergy offered to grant Xcel the option to extend the PPA in five year increments at a reduced capacity price for up to three additional five year terms.[147]

X. The Department's Proposed Corrections to Calpine's Bid

148. The Department adjusted Calpine's bid to reflect a summer-time decrease in capacity. Many natural gas-fired units have a lower capacity in summer than in winter for accreditation and energy production purposes.[148]

149. Using Calpine's estimate of summer and winter capacities, and the rating factors from other recently-added generation units – including Blue Lake 7, Blue Lake 8, Angus Anson 4, and Calpine's existing unit at the Mankato Energy Center – the Department added a deration pattern for the proposed Calpine unit. Further, a summer-time capacity deration was included in the inputs of each offeror that proposed a thermal unit.[149]

150. Calpine's response to discovery included an updated cost estimate for facilities upgrades that would be necessary in the event that Calpine's proposal was selected. It estimated those costs in the range of "$650,000 to $1,500,000 with a final cost to be confirmed upon completion of the facilities study." The Department included facilities costs in its Strategist analysis. Specifically, Dr. Rakow levelized the $1.5 million cost using the most recent levelized annual revenue requirement (LARR) data available – a revenue requirement amount of 12.17 percent. With this adjustment, the Department converted the proposed up-front capital costs into a stream of level payments over a period of years. It concluded that the capital costs have a discounted present value of approximately $1.55 million.[150]

151. The $1.55 million cost was reasonably included in a post-model Present Value Rate of Return (PVRR) adjustment for all scenarios and contingencies evaluating Calpine's proposal.[151]

152. Calpine suggested no corrections to Dr. Rakow's inputs, but did suggest separate treatment for fixed operation costs, maintenance costs and start charges.

[146] Ex. 69 at 17 (Ewan Rebuttal).

[147] Ex. 69 at 4 and 17 (Ewan Rebuttal); Trade Secret Ex. 87 attachment SR-R-9 at 3-4 (Rakow Rebuttal).

[148] Ex. 83 at 7 (Rakow Direct).

[149] *Id.*

[150] The 12.17 percent LARR is the most recent estimate available. DOC Ex. 83 at 7 (Rakow Direct).

[151] Ex. 83 at 7-8 (Rakow Direct).

Dr. Rakow explained that he could not find a way to adequately model start changes as a variable cost. Thus, the Department retained the inputs as presented by Calpine.[152]

XI. The Department's Proposed Corrections to Geronimo's Bid

153. The Department assumed that if Geronimo's proposal was selected by the Commission, there would be no reduction in costs to meet the Solar Energy Standard (SES). For the purposes of its evaluation of proposals, the Department assumed that the added value of Geronimo's proposal as a SES-qualifying generation source was zero.[153]

154. The Department asserts that because Xcel's RFP did not call for SES-qualifying solutions, the value of this feature of Geronimo's proposal is zero.[154]

155. Notwithstanding the valuation conferred by the Department, the Solar Renewable Energy Credits (S-RECs) do have a separate market value, and this value is more than zero. S-RECs are sold in other states at prices between $13/S-REC to more than $200/S-REC.[155]

156. At a price of $5 for each marketable S-REC, the Geronimo proposal will result in a PVSC reduction of $10 million annually. At a price of $20 for each marketable S-REC, the Geronimo proposal will result in a PVSC reduction of $38 million annually.[156]

157. If Geronimo's proposal is selected by the Commission, Xcel will use the solar energy generated by the project to meet the requirements of Minnesota Solar Energy Standard.[157]

158. Expressing doubt as to the commercial maturity of solar projects, Dr. Rakow and the Department urge the Commission to host a follow-on procurement that is limited to solar energy generation sources.[158]

XII. The Department's Proposed Corrections to GRE's Bid

159. GRE reported that the Department's Strategist outputs contained an error in cost. Dr. Rakow compared the costs of the GRE proposal reported by Strategist to the cost contained in GRE's original proposal. Following this review he agreed that

[152] Ex. 83 at 6 (Rakow Direct).

[153] Ex. 83 at 8-11 (Rakow Direct); Hearing Transcript, Vol. 2 at 145.

[154] Ex. 83 at 10-11 (Rakow Direct).

[155] Ex. 59 at 18-19 (Engelking Rebuttal).

[156] Ex. 59 at 18-19 and Table 2 (Engelking Rebuttal).

[157] Hearing Transcript, Vol. 1 at 137.

[158] Ex. 83 at 12-13 (Rakow Direct).

there had been a series of faulty inputs. The Department revised and updated the cost inputs.[159]

XIII. The Department's Proposed Corrections to Invenergy's Bid

160. Invenergy suggested three corrections to the Department's Strategist analysis. First, the company noted that its Hampton Center proposal price was incorrect on the input spreadsheet and the Department corrected this input.[160]

161. Second, Invenergy stated that the data sent by the Department assumed a $4/MMBtu natural gas price, when, in fact, the natural gas costs used in the Strategist runs were above $6/MMBtu. Although Invenergy was correct as to the discrepancy, the error did not impact Invenergy more than other bidders' proposals. This is because within the Department's model, the price of natural gas was a background assumption that permitted comparison of the inputs and outputs of all Bidders' proposals.[161]

162. Third, Invenergy was unable to replicate the emissions values developed by the Department. Dr. Rakow further reviewed the inputs for SO_2, NO_x, CO, and PM_{10} emissions for Invenergy's bids. He divided the emissions input provided for Xcel's Black Dog unit 6 by the emissions input provided by Xcel in its Strategist input worksheet. Moreover, he undertook a similar calculation with Invenergy's data. He then compared these sums to ratios derived from the Strategist outputs. The result was that the ratios were very close. For SO_2, the difference (ratio of bidder provided inputs to ratio of Strategist outputs) was about three percent; for NOx, PM_{10}, and CO the difference was about one percent.[162]

163. The Department determined that the differences were very close such that Strategist accurately reflected the inputs provided by the bidders.[163]

XIV. The Department's Proposed Corrections to Xcel's Bid

164. Xcel provided a spreadsheet that corrected the base year revenue requirements (capital cost) inputs for its proposals. Dr. Rakow revised Xcel's calculations for Black Dog Unit 6 assuming a 2018 in-service date as well as Black Dog Unit 6 assuming a 2019 in-service date. He then used the revised results for the base year revenue requirements for Black Dog Unit 6 and Red River Units 1 and 2.[164]

XV. Strategist Model and the Forecasts of Future Needs

165. On behalf of the Department, Dr. Rakow conducted a series of analyses using Strategist modeling software. Strategist is a "capacity expansion model." It

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[159] Ex. 83 at 14 (Rakow Direct).

[160] *Id.*

[161] *Id.*

[162] *Id.* at 14-15.

[163] *Id.*

[164] *Id.* at 15.

determines the set of resources that are the least cost method to meet increases in demand in the future.[165]

166. The Department's Strategist analysis began with inputs from Xcel's fall 2011 sales forecast.[166]

167. Since 2011, however, Xcel has produced additional forecasts; including its spring 2013 forecast.[167]

168. In its spring 2013 forecast, Xcel predicts that its customers will use less energy and capacity in the initial years compared to the fall 2011 forecast. In future years, Xcel predicts that customers will continue to use less energy while making higher demands on Xcel's peak compared to the fall 2011 forecast.[168]

169. Xcel forecasts a significant decrease in the overall load factor of its system.[169]

170. The Department has not verified the accuracy of Xcel's spring 2013 sales forecast. However, the Department analysis does include sales levels that are even lower than Xcel's spring 2013 sales forecast.[170]

171. The Department included in its analysis different assumptions regarding the amount of capacity that is reserved to serve load during periods of peak demand on the electrical system. On the Department's behalf, Dr. Rakow considered two different methods: the reserve ratio used by Xcel in its 2010 IRP and a new reserve ratio to be used by MISO for its peak.[171]

172. The new MISO method is likely to have a significant effect on the amount of reserve capacity that MISO may require of Xcel in future years. This amount is likely to be much lower than the reserves required in 2011.[172]

173. The Department is continuing to evaluate how MISO's changing methods may impact Minnesota's resource planning.[173]

174. Xcel's peak reliability method (also known as "non-coincident peak" method) refers to the reliability method used during the analysis of Xcel's last Commission-approved resource plan – the 2010 IRP. Under this method a 3.79 percent

[165] *Id*. at 5 and 14, n.4.

[166] Ex. 76 at 14 (Shah Direct).

[167] *Id*. at 3-7.

[168] *Id*. at 8-10.

[169] *Id*. at 10.

[170] Hearing Transcript, Vol. 2 at 14 and 32-33; Ex. 76 at 7-13 (Shah Direct); Ex. 78 at 4 (Shah Rebuttal).

[171] Ex. 83 at 22-25 (Rakow Direct).

[172] *Id*. at 23 n.11 and 27.

[173] *Id*. at 23 n.11.

reserve ratio was added to Xcel's forecast of the Company's peak demand – the peak demand that is non-coincident with any other entity's peak. With this capacity target in mind, the Strategist modeling software added resources until Xcel had sufficient capacity to cover both the Company's peak demand forecast and the required reserves.[174]

175. This was the method used by MISO for the June 2012 to May 2013 planning year. It is also the method used by Xcel in its most recent resource plan.[175]

176. The term "MISO coincident peak" refers to a new reliability method to be used by MISO for the June 2013 to May 2014 planning year. This reliability method requires that a 6.2 percent reserve ratio be added to Xcel's forecast of its demand at the time of (or coincident with) the MISO system peak.[176]

177. The new reliability method recognizes that the peak demand on Xcel's system may occur on different days, or at different hours on the same day, as the peak demand on the MISO system.[177]

178. The MISO coincident peak demand is determined by discounting the non-coincident peak demand (i.e. the utility's peak demand) by a diversity factor. For example, if Xcel's peak demand is 100x, but the demand on its system is only 90x at the time that the broader MISO system hits its peak, the diversity factor between the two systems would be the difference between 100 and 90: 10 percent.[178]

179. The Department is not able to accurately forecast the amount of reserves that will be required under the new MISO requirements. For instance, it is not clear which diversity factor should be applied to discount non-coincident peak demand. There are several different alternatives that one may apply. Likewise, it is not clear to what extent demand side management (DSM) measures will reduce Xcel's non-coincident peak demand. Xcel's Saver's Switch air conditioning interruption program, for example, can reduce hour-by-hour demand for energy by approximately 100 MW.[179]

180. The forecasted amount of Xcel's needs varies depending upon whether one uses the previous reliability calculation method or MISO's new method. Moreover, the difference in forecasts is substantial. When the new MISO method of calculating reserves is used, there is a reduction in net peak demand of between about 275 MW and 290 MW each year.[180]

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[174] *Id*. at 22-23.

[175] *Id*. at 22.

[176] *Id*. at 22-23.

[177] *See generally, Id*. at 23-24.

[178] *Id*. at 23 and n.12.

[179] *Id*. at 24-25.

[180] *Id.*

181. Both the Department and Xcel only evaluated combinations of energy plants that produced 300 MW by 2019.[181]

182. The identified need was just larger than Calpine's Mankato facility rated summer capacity of 278 MW.[182]

183. The minimum quantity was also more than 11 times Xcel's most-recent projection of need for 2019 – 26 MW.[183]

184. As configured by the Department and Xcel, when the Strategist model identifies a shortfall in generation, even as small as 1 or 2 MW, the model selects the next full plant to meet the added need. The selection of an additional plant is undertaken even if the added plant capacity is many times the remaining shortfall.[184]

XVI. Strategist Base Case Development

185. To develop a "no build" or base case for Strategist the Department updated its most recent Strategist analysis of Xcel's system as follows:

a. Re-established Xcel's CT and combined cycle (CC) optional expansion units in the years 2027 and beyond;

b. Eliminated the optional wind expansion units.

c. Re-established Xcel's "hard wired" or "forced" wind expansion units for the years 2012 and beyond to ensure that the existing renewable energy standard (RES) is met in Strategist.

d. Established the new fuel and associated inflation rates required for Xcel's proposed North Dakota units.

e. Removed the Goodhue Wind unit from Xcel's generation portfolio because the wind farm will not be built.

f. Updated the inputs for the LS Power (Cottage Grove) combined cycle unit in accordance with Xcel's 2013 database, as provided in DOC Information Request No. 1.

g. Updated the inputs for Xcel's Prairie Island units, largely removing the capacity attributable to the extended power uprate (Docket No. E002/CN-08-509) per Xcel's 2013 database.

h. Updated the wholesale market price inputs per Xcel's 2013 database.

[181] Ex. 46 at 25-27 (Wishart Direct); Ex. 83 at 26 (Rakow Direct); Ex. 86 at 3 (Rakow Rebuttal).

[182] Ex. 46 at 2 and 16 (Wishart Direct).

[183] *Id. at* 10.

[184] Hearing Transcript, Vol. 1 at 105; *see also,* Ex. 83 at 16 (Rakow Direct).

i. Updated the retirement dates for Xcel's Black Dog units 3 and 4 and French Island unit 3 per Xcel's 2013 database.

j. Updated the in-service (repair) date for Xcel's French Island unit 3 per Xcel's 2013 database.

k. Added about 290 MW nameplate capacity, 200 MW accredited capacity, and 490 GWh of solar energy by 2020 to meet the SES.

l. Updated the externality values per the Commission's June 5, 2013 Notice of Updated Environmental Externality Values (Docket Nos. E999/CI-93-583 and E999/CI-00-1636).

m. Updated the heat rates for the nuclear and generic units per Xcel's 2013 database.

n. Updated the coal, nuclear, biomass, natural gas fuel costs for the existing units per Xcel's 2013 database.

o. Updated the natural gas fuel costs for generic expansion units per Xcel's 2013 database.

p. Updated the monthly pattern for natural gas per Xcel's 2013 database.

q. Updated the variable operations and maintenance costs for certain existing units per Xcel's 2013 database.

r. Updated the wholesale energy market costs per Xcel's 2013 database.[185]

186. Xcel's 2011 and 2013 databases have the same number of wind expansion units through 2019, after which the "2013 database" has one, two or three additional wind expansion units each year. Dr. Rakow concluded the small number of additional units, at that distance in the future, did not impact the overall analysis.[186]

XVII. Using Generic Credits to Equalize Proposals for Evaluation

187. To affect comparisons between proposals of very different sizes, the Department added generic energy units to its modeling of particular bid packages so as to compare the life-cycle costs of a common package across bidders. The price of a generic unit was based upon the estimate current cost to construct a particular type of energy generation unit, escalated over time for inflation.[187]

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185 Ex. 83 at 17-19 (Rakow Direct); *see also,* Ex. 84 SR-2 (Rakow Direct Attachments); *Order Declining to Extend Certificate of Need, Finding Statutory Violation, Requiring Further Filings, and Giving Notice of Intent to Revoke Site Permit* in Docket Nos. IP6701/CN-09-1186, IP6701/WS-08-1233, IP6701/M-09-1349, and IP6701/M-09-1350 (July 26, 2013).

186 Ex. 83 at 17-18 (Rakow Direct).

187 *See, e.g.,* Hearing Transcript, Vol. 1 at 109-110.

188. In this case, Xcel used internal information that it had as to plant costs to develop a price for generic gas units.[188]

189. Xcel likewise developed a price for generic units of solar energy. In this instance, however, Xcel did not have internal cost or pricing information available. Instead, Xcel drew upon bidding information for solar projects in other jurisdictions and adjusted those figures "to reflect what we thought the cost in Minnesota specifically would be."[189]

190. Both Xcel and the Department used the same base assumptions with respect to the cost of generic gas and solar units.[190]

191. There are risks associated with adding generic units to proposals during the evaluation process. Smaller proposals rely more upon generic units to account for the stated capacity needs than proposals with larger capacities. Accordingly, if the generic units are more expensive than an offeror's proposal price, adding these expensive units to the model works to the disadvantage of the smaller packages. Larger proposals will tend to look cheaper in a Strategist modeling of outcomes than smaller packages that include generic units.[191]

192. The generic gas unit price that Xcel developed was higher than the prices of the gas plants bid in this docket. As a result, each of the gas proposals bid in this proceeding was comparably less expensive than the generic units; a fact that benefited the gas proposals during the evaluation process.[192]

193. The generic solar unit price that Xcel developed was lower than the prices of the solar plant bid in this docket. As a result, Geronimo's proposal was evaluated as comparably more expensive than the generic units; a fact that disadvantaged its proposal during the evaluation process.[193]

XVIII. Evaluating Interconnection Costs and Savings

194. The Department reviewed the costs associated with interconnecting the proposed projects to the transmission system, including the potential for curtailment or congestion charges.[194]

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[188] Hearing Transcript, Vol. 1 at 110.

[189] *Id*.

[190] Ex. 59 (Engelking Rebuttal, Schedule EME-3).

[191] Ex. 83 at 29-32 (Rakow Direct).

[192] Ex. 83 at 30 (Rakow Direct).

[193] Ex. 46 at 36 (Wishart Direct); Ex. 59 (Engelking Rebuttal, Schedule EME-3); Ex. 83 at 30 (Rakow Direct); Hearing Transcript, Vol. 1 at 110.

[194] Hearing Transcript, Vol. 2 at 39 (Shaw).

195. Xcel stated that it does not expect any of the bid proposals to have significant congestion charges and, thus, the Department did not add congestion charges to its Strategist analysis.[195]

196. The offerors do treat interconnection costs, including potential network upgrade costs, in very different ways.[196]

197. Concerned that Xcel and Invenergy expected ratepayers to cover interconnection costs, the Department notified offerors that it would oppose efforts to recover from ratepayers costs that were not included in their respective proposals.[197]

198. Calpine responded to the Department's notice that its bid did not include MISO's estimated cost of necessary upgrades for its Mankato bid of $650,000 to $1,500,000 with "a final cost to be confirmed upon completion of the facilities study."[198]

199. Dr. Rakow included a $1,550,000 upgrade cost in the Strategist analysis for Calpine's Mankato proposal.[199]

200. Invenergy included $7 million for interconnection costs in its Cannon Falls proposal, but identified a formula to calculate increases or decreases to that amount.[200]

201. Invenergy failed to show the reasonableness of its suggestion that unknown costs be shifted to ratepayers following the Commission's selection of proposals.[201]

202. Xcel proposes to pass extra costs on to ratepayers through a rider to its tariff.[202]

203. To the extent that Xcel's proposal permits it to avoid submitting firm pricing for interconnection costs, it is prejudicial to ratepayers and other offerors.[203]

204. By locating the distributed sites in close proximity to load centers, Geronimo's proposal will reduce transmission line losses that occur whenever energy is transmitted across the wires and transformers of an electric system.[204]

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[195] Ex. 79 at 5 (Shaw Direct).

[196] *Id. at* 2-4.

[197] Ex. 79 at 2-4 (Shaw Direct); Ex. 82 at 4 (Shaw Rebuttal); Ex 83 at 7-8 (Rakow Direct).

[198] Ex. 79 at 4 (Shaw Direct).

[199] Ex. 83 at 7 (Rakow Direct).

[200] Ex. 79 at 3-4 (Shaw Direct).

[201] *Id*.

[202] Ex. 82 at 1-3 (Shaw Rebuttal).

[203] *Id*.

[204] Ex. 62 at 4 (Skarbakka Direct).

205. Based upon demand loss factors by voltage level, Geronimo's proposal will result in a four percent reduction in transmission line losses. This reduction results in a PVSC savings of approximately $9 million.[205]

206. Xcel acknowledges that, if accepted, Geronimo's proposal will result in a reduction in transmission losses and that those avoided transmission line losses are not captured in either Xcel's or the Department's models.[206]

207. By selecting sites that will be interconnected on the distribution system, Geronimo's dispatching of energy has the potential to reduce peak loading on Xcel's transmission system. These reductions make existing transmission capacity available to meet future needs and permit Xcel to avoid costs to expand its transmission system.[207]

208. Using MISO's rate for network integration service on Xcel's system, the avoided transmission capacity benefits associated with Geronimo's proposal is approximately $3.24 million each year.[208]

209. Neither the Department nor Xcel evaluated the benefits of avoiding additional transmission capacity costs.[209]

210. These savings reduce the PVSC for Geronimo's project by $33 million.[210]

XIX. The Department's Strategist Analysis

211. Each Bidder completed the Strategist template data form that is available on Xcel's website and forwarded the completed templates to the Department. Then, Dr. Rakow either entered this data directly into Strategist or calculated the required inputs from the Strategist template data to complete a series of computer models.[211]

212. From the computer runs that he completed, Dr. Rakow downloaded data as to how each proposal performed. Dr. Rakow then sent each offeror the data corresponding to its proposal. With these disclosures, offerors were able to review how their proposed solutions performed – in terms of cost, fuel consumption, pollutants emitted, and other factors – under a variety of different conditions.[212]

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[205] Ex. 13 at 31 (Distributed Solar Energy Proposal); Ex. 61 at 7 (Beach Rebuttal).

[206] Ex. 46 at 35 (Wishart Direct).

[207] *See,* Ex. 13 at 9-12 (Geronimo Proposal).

[208] Ex. 61 at 9 (Beach Rebuttal).

[209] *Id. at* 7.

[210] *Id.*; Ex. 59 at 20 (Engelking Rebuttal).

[211] Ex. 83 at 5 (Rakow Direct); *see also,* Department's May 3, 2013 Comments, CN-12-1240.

[212] Ex. 83 at 5-6 (Rakow Direct).

213. Dr. Rakow's Strategist analyses included a series of capacity and performance assumptions. For example, in one instance, Dr. Rakow programmed Strategist to add 100 MW of short term capacity (forced into the supply mix during June, July, and August) in both 2015 and 2016. Through this limitation, Strategist assessed whether the packages covered the capacity deficits in the 2017 to 2020 time frame or whether additional long term capacity (from generic units) was needed.[213]

214. Additionally, Dr. Rakow analyzed proposal performance at different levels of forecasted need. For the "high forecast contingency," Dr. Rakow programmed Strategist to add 400 MW of short term capacity in 2015 and 500 MW in 2016. For the "mid-high forecast contingency," he obliged Strategist to add 100 MW of short term capacity in 2015 and 250 MW in 2016.[214]

215. During a "first round" of analyses, Dr. Rakow assessed all possible bid packages that were less than 700 MW in size. From this range of proposals, he created a "short list" of the bids or packages that, in his view, warranted more detailed economic analysis during a "second round" of analysis.[215]

216. From the results of the first round of its Strategist analysis, the Department selected seven packages for more detailed analysis:

1. BD617— Xcel's Black Dog Unit 6, with an in-service date of 2017 and CCC1 — Calpine's Combined Cycle Mankato Energy Center expansion proposal;
2. ICT1— Invenergy Combustion Turbine proposal 1 (Cannon Falls);
3. GPV1— Geronimo Solar proposal, "bundled" pricing;
4. BD619 CCC1 — Xcel's Black Dog Unit 6, with an in-service date of 2019 and Calpine's CC Mankato Energy Center expansion proposal;
5. ICT1, BD618 — Invenergy Combustion Turbine proposal 1 (Cannon Falls) and Black Dog unit 6 in-service by 2018;
6. ICT1 CCC1 — Invenergy Combustion Turbine proposal 1 (Cannon Falls) and Calpine's CC Mankato Energy Center expansion proposal; and
7. The Base Case — a no-build alternative.[216]

217. Dr. Rakow's first round of modeling revealed that Xcel's Black Dog CT unit and Calpine's CC unit (number 4 in the listing immediately above) was the highest ranked proposal under all 24 scenarios.[217]

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[213] Ex. 83 at 37 (Rakow Direct).

[214] *Id.* at 37-38.

[215] *Id.* at 5.

[216] *Id.* at 35.

[217] *Id.* at 34.

218. Xcel also undertook analyses of proposals using Strategist modeling software. The Black Dog 6 unit was the lowest-cost resource of the proposals that Xcel reviewed and was a feature of each of the top 20 highest-rated plans in its modeling.[218]

219. Importantly, however, the Black Dog 6 Unit is a large unit. To broaden and deepen the Department's analyses, Dr. Rakow analyzed the effects of deploying smaller energy solutions (and covering the deficits for a shorter period of time) and adjusting the proposed in-service dates of energy generation sources.[219]

220. For the base case in a second round of analysis, the Department used: (a) Xcel's 2011 forecast of need; (b) a non-coincident peak reliability method; (c) the assumed acquisition 800 MW of wind; and (d) an accreditation factor for solar energy solutions of 72 percent.[220]

221. Against these assumptions, the Department tested a set of contingencies drawn from Xcel's most recent resource plan. The resulting list of contingencies for the second round included:

- a statutory mandate on CO_2 reduction;
- use of the Commission's high and low CO_2 internal cost values;
- low externality values;
- high and low wholesale market prices (±25 percent);
- high and low capital costs (±10 percent);
- high and low coal costs (±20 percent and ±10 percent);
- low natural gas costs (-$1.50, -$1.00, -$0.50);
- high natural gas costs (+$2.50, +$2.00, +$1.50 + $1.00, and, +$0.50);
- high and low wind accreditation (±25 percent); and
- high and low forecast of energy and demand (±5 percent and ±2.5 percent).[221]

222. Additionally, the Department ran each scenario and contingency a second time with the Commission's CO_2 internal cost and externality values removed.[222]

223. Following a second round of analyses, Dr. Rakow's Strategist modeling gave the highest rating to Calpine's proposal when combined with Xcel's Black Dog Unit

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218 Ex. 46 at 19 (Wishart Direct); Hearing Transcript, Vol. 1 at 124.

219 Ex. 83 at 36-37 (Rakow Direct).

220 *Id.* at 36.

221 *Id.* at 36-37.

222 *Id.* at 37.

6 (and a 2019 in-service date for the Black Dog unit). When combined, these units cover the capacity deficits through 2023; and, if demand is lower than was projected in 2011, perhaps much longer.[223]

224. During a "third round" of Strategist analyses, the Department included assumptions regarding interruptible natural gas supply and flexible in-service dates. The Department's earlier analyses had assumed the use of firm natural gas supplies for all offerors that proposed a thermal solution.[224]

225. Assuming use of a firm natural gas supply favored Calpine's Mankato project and Xcel's Black Dog Unit 6 and disfavored Invenergy's proposal.[225]

226. The results of the third round of Department analyses identified three top performing packages:

a. Calpine's Mankato proposal with Black Dog Unit 6,

b. Calpine's Mankato proposal with Invenergy's Cannon Falls proposal, and

c. Invenergy's Cannon Falls proposal with Xcel's Black Dog unit 6.[226]

227. If the Department assumed both flexible in-service dates and the use of interruptible gas supplies, the cost of Invenergy's Cannon Falls proposal was significantly reduced.[227]

228. The Department recommended that PPA negotiations include consideration of firm and interruptible gas supply as well as flexible in-service dates. It recommended that such negotiations be limited to Xcel, Calpine and Invenergy and that, based upon the results of these negotiations, two of three projects should be selected by the Commission.[228]

229. Dr. Rakow also concluded that Geronimo's solar energy proposal was "significantly below the top performing packages in terms of Strategist results."[229]

XX. Statutory and Regulatory Requirements for this Proceeding

230. While Minn. Stat. § 216B.2422, subd. 5 authorizes a utility to "select resources to meet its projected energy demand through a bidding process approved or

[223] Ex. 83 at 40 and 43 (Rakow Direct); Ex. 84 SR-5A (Rakow Direct Attachments).

[224] Ex. 86 at 4 (Rakow Rebuttal).

[225] *Id.* at 4-5.

[226] Ex. 86 at 12 (Rakow Rebuttal).

[227] Ex. 86 at 10-12 (Rakow Rebuttal); Ex. 88 at SR-R-11A (Rakow Rebuttal Attachments).

[228] Ex. 86 at 2, 15 and 21 (Rakow Rebuttal); Hearing Transcript, Vol. 2 at 50 (Rakow).

[229] Ex. 83 at 16 (Rakow Rebuttal).

established by the Commission," and to exempt selected proposals from the requirement to obtain a Certificate of Need, the Commission has decided to condition its approval powers in this case. In part, this is because Xcel is both the public utility with a resource need and an offeror with a proposal of its own to meet that need. In this circumstance, the Commission decided that it will compare competing proposals against the ordinary Certificate of Need criteria.[230]

231. Minn. Stat. § 216B.243 provides that in assessing need, the Commission shall evaluate:

> (1) the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based;
>
> (2) the effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand;
>
> (3) the relationship of the proposed facility to overall state energy needs, as described in the most recent state energy policy and conservation report prepared under section 216C.18, or, in the case of a high-voltage transmission line, the relationship of the proposed line to regional energy needs, as presented in the transmission plan submitted under section 216B.2425;
>
> (4) promotional activities that may have given rise to the demand for this facility;
>
> (5) benefits of this facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region;
>
> (6) possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation;
>
> (7) the policies, rules, and regulations of other state and federal agencies and local governments;
>
> (8) any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically;
>
> (9) with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these

[230] NOTICE AND ORDER FOR HEARING, OAH 8-2500-30760 at 5 (June 21, 2013); Minn. Stat. § 216B.243, subd. 5.

factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota;

(10) whether the applicant or applicants are in compliance with applicable provisions of sections 216B.1691 and 216B.2425, subdivision 7, and have filed or will file by a date certain an application for certificate of need under this section or for certification as a priority electric transmission project under section 216B.2425 for any transmission facilities or upgrades identified under section 216B.2425, subdivision 7;

(11) whether the applicant has made the demonstrations required under subdivision 3a; and

(12) if the applicant is proposing a nonrenewable generating plant, the applicant's assessment of the risk of environmental costs and regulation on that proposed facility over the expected useful life of the plant, including a proposed means of allocating costs associated with that risk.[231]

232. Minn. R. 7849.0120 summarizes the statutory criteria found in Minn. Stat. § 216B.243 as follows:

(F) 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 … ;

(G) a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record … ;

(H) 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 … ; and

(I) 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.[232]

233. Importantly, however, Minn. Stat. § 216B.2422, subd. 4, places a limitation on the Commission's powers to confer a certificate of need. The statute provides that the Commission "shall not approve a . . . nonrenewable energy facility in an integrated

[231] Minn. Stat. § 216B.243, subd. 3.

[232] Minn. R. 7849.0120.

resource plan or a certificate of need . . . unless the utility has demonstrated that a renewable energy facility is not in the public interest."[233]

234. Section 216B.2422, subd. 4 further provides that the determination of the public interest must include consideration of whether the resource plan helps the utility to achieve Minnesota's greenhouse gas reduction goals, renewable energy standard, or the solar energy standard.[234]

235. Minn. Stat. § 216B.2426 requires that the Commission ensure that "opportunities for the installation of distributed generation" are considered in resource planning and certificate of need proceedings.[235]

XXI. Impact upon Adequacy, Reliability or Efficiency of the Energy Supply

236. The first criterion under Minn. R. 7849.0120 is whether the proposed resource would have adverse effects upon the future adequacy, reliability, or efficiency of energy supply of the utility, its customers, or to the people of Minnesota and neighboring states.[236]

237. Xcel's needs for additional capacity are undergoing significant change because of three key factors: (1) lower overall demand; (2) the addition of between 72 and 200 MW of accredited capacity from solar resources, needed to meet Minnesota's Solar Energy Standard; and (3) new reserve margin requirements issued by MISO.[237]

238. Taking into account only the first two factors – lower overall demand and the new solar resource standard – Xcel projects that it will have a generating capacity shortfall of 93 MW in 2017. This shortfall might conceivably grow to 307 MW by 2019.[238]

239. However, if MISO's reserve requirements are calculated on the basis of coincident peaks, as they are today, the projected deficit in generation capacity shrinks even further. If all three factors reducing the need for capacity are considered, Xcel does not face a shortfall of generation capacity until 2019. Moreover, this deficit grows only by 26 MW by 2019.[239]

240. Generation from solar power sources is the greatest on sunny days during the summer. Xcel's peak demand for electricity most often occurs on sunny days during the summer.[240]

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233 Minn. Stat. § 216B.2422, subd. 4; *see also,* Minn. Stat. § 216B.243, subd. 3a.

234 Minn. Stat. § 216B.2422, subd. 4.

235 Minn. Stat. § 216B.2426.

236 Minn. R. 7849.0120 (A).

237 Ex. 46 at 7-8 (Wishart Direct); Ex. 83 at 19 (Rakow Direct).

238 Ex. 46 at 7 and Table 2 (Wishart Direct).

239 Ex. 46 at 8-10 and Table 4 (Wishart Direct).

240 Ex. 60 at 12-13 and 15-16 (Beach Direct).

241. Geronimo's proposal includes features – such as tracking system technology, appropriately-sized modules, and distributed sites – to ensure that the project reliably delivers energy capacity.[241]

242. Geronimo proposes to generate energy from approximately 20 different locations across Xcel's service territory. These facilities will generate between 2 MW and 10 MW of electricity. Each site will be served by separate interconnection facilities.[242]

243. A distributed network of generation reduces the risk of outages at any particular point of the transmission system.[243]

244. A distributed network of generation reduces transmission line losses. This reduction results in a PVSC savings of approximately $9 million.[244]

245. Geronimo proposes an in-service date of December 2016, so as to ensure that its generation capacity would be available to meet any of Xcel's capacity needs in the summer of 2017.[245]

246. GRE proposes to sell capacity from its existing generators to Xcel.[246]

247. Those energy resources are fully integrated into the existing transmission system and dispatched by MISO within its energy market.[247]

248. Over the three-year period that includes 2017, 2018 and 2019, GRE's proposal is fully scalable. It will sell Xcel needed capacity for one, two or three years, as Xcel's reserve requirements become apparent.[248]

249. The most efficient solution in this circumstance is to select scalable projects that meet Xcel's near-term shortfalls (as described in Table 4 of Mr. Wishart's Direct Testimony) and for the Commission to conduct a second procurement for needs which may occur after 2019.[249]

[241] Ex. 60 at 3-5 and 18-19 (Beach Direct); Ex. 62 at 4 (Skarbakka Direct).

[242] Ex. 57 at 9 (Engelking Direct).

[243] Ex. 62 at 3-4 (Skarbakka Direct).

[244] Ex. 13 at 31 (Distributed Solar Energy Proposal); Ex. 61 at 7 (Beach Rebuttal).

[245] Ex. 57 at 7 (Engelking Direct).

[246] Ex. 63 at 3 (Selander Direct).

[247] Ex. 63 at 3 (Selander Direct).

[248] Ex. 63 at 2-3 (Selander Direct); Ex. 64 at 3 (Selander Rebuttal).

[249] *See generally,* Ex. 46 at 8-10 and Table 4 (Wishart Direct).

250. It is not efficient to procure one or more gas turbines when the projected needs through 2019 are modest – and may be getting smaller.[250]

XXII. The Most Reasonable and Prudent Alternative

251. The second criterion under Minn. R. 7849.0120 is whether a more reasonable and prudent alternative to the proposed facility has been demonstrated by a preponderance of the evidence on the record.[251]

252. Xcel asserts that the least-cost plan that includes the Geronimo proposal is a package that combines Invenergy's Cannon Falls Facility and the Geronimo proposal, with in-service dates for each in 2016, with Black Dog Unit 6 joining the group in 2019. Xcel calculates the PVSC for this combination as $34 million higher than its least-cost plan.[252]

253. In this circumstance, a levelized cost of electricity (LCOE) points to a better prediction of costs and impacts to ratepayers.[253]

254. LCOE represents the net present value of the expected annual costs – including variable and fixed operations and maintenance costs, capital costs and the return on investment – divided by annual generation over the term of the proposal.[254]

255. When one accounts for avoided energy costs, avoided capacity costs, avoided transmission costs, the impact of emissions and the cost to Xcel from transmission line losses, the benefits of Geronimo's proposal amounts to a savings of $46 million of net present value of societal costs.[255]

256. Geronimo's proposal likewise manages future risk. Because its facilities create energy from sunlight, Geronimo's solution poses no risk of higher fuel costs in the future.[256]

257. On a per MWh basis, a solar unit is also the lowest cost standalone resource.[257]

258. The most reasonable and prudent solution in this circumstance is to select scalable projects that meet Xcel's near-term shortfalls (as described in Table 4 of

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[250] *Id.*

[251] Minn. R. 7849.0120 (B).

[252] Ex. 46 at 34-35 (Wishart Direct).

[253] *See generally,* Ex. 52 at 7 (Hibbard Direct).

[254] Ex. 52 at 6 (Hibbard Direct).

[255] Ex. 13 at 31 (Distributed Solar Energy Proposal); Ex. 59 at 18-19 (Engelking Direct); Ex. 58 at 18 (Engelking Rebuttal); Ex. 61 at 7 (Beach Rebuttal)**.**

[256] Ex. 13 at 19 (Distributed Solar Energy Proposal).

[257] *See,* Ex. 74 at 7 (Norman Rebuttal).

Mr. Wishart's Direct Testimony) and for the Commission to conduct a second procurement for needs which may occur after 2019.[258]

259. Combining Geronimo's proposal with GRE's proposal, represents the most reasonable and prudent alternative to meet Xcel's near-term needs.[259]

260. It is not reasonable and prudent to procure one or more gas turbines, when the projected needs through 2019 are modest – and may be getting smaller.[260]

261. If gas turbines are needed to meet larger, forecasted needs after 2019, these turbines can be constructed and placed into service within 21 months of a need determination by the Commission.[261]

262. The Department's Strategist analysis does not lead to identification of a more reasonable alternative than acceptance of Geronimo's proposal – particularly when it is combined with acceptance of GRE's capacity offer.[262]

263. A reasonable and prudent purchaser of energy resources would not have assumed that the value of an SES-qualifying generation source was zero.[263]

264. A reasonable and prudent purchaser of energy resources would not have assumed that the value of avoiding transmission line losses was zero.[264]

265. A reasonable and prudent purchaser of energy resources, for Xcel's stated needs, would not have relied upon Xcel's Fall 2011 sales forecast alone.[265]

266. A reasonable and prudent purchaser of energy resources, for Xcel's stated needs, would not have limited the evaluation to energy plants that produced 300 MW by 2019.[266]

267. A reasonable and prudent purchaser of energy resources would not risk incurring project cancellation costs when other, reasonably-priced and scalable alternatives exist.[267]

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[258] *See generally,* Ex. 46 at 8-10 and Table 4 (Wishart Direct).

[259] *See,* Section XXII.

[260] *Id*.

[261] Ex. 38 at 6 (Environmental Report); *see also,* Ex. 70 attachment 1 at 8 (Shield Direct).

[262] *See,* Section XXII.

[263] *Compare,* Ex. 83 at 8-10 (Rakow Direct); Hearing Transcript, Vol. 1 at 145 with Ex. 59 at 18-19 (Engelking Rebuttal).

[264] *See generally,* Ex. 46 at 35 (Wishart Direct); Hearing Transcript, Vol. 2 at 45.

[265] Hearing Transcript - Vol. 2 at 30.

[266] *Compare*, Ex. 46 at 25-27 (Wishart Direct); Ex. 83 at 26 (Rakow Direct); Ex. 86 at 3 (Rakow Rebuttal); Hearing Transcript - Vol. 2 at 29-30 with Ex. 46 at 10 (Wishart Direct).

[267] *See generally,* Hearing Transcript, Vol. 1 at 126-27.

XXIII. Compatibility with Our Socioeconomic and Natural Environments

268. The third criterion under Minn. R. 7849.0120 is whether the proposed resource will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health.[268]

269. Geronimo's proposal will benefit society in ways that are consistent with the natural environment. Importantly, the construction and operation of Geronimo's Proposal will not generate carbon dioxide (CO_2) or "criteria pollutants."[269]

270. Criteria pollutants include sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), lead (Pb), and particulate matter (PM).[270]

271. Sulfur dioxide causes acid rain and human respiratory illness. Nitrogen oxides are greenhouse gases that cause ozone and related respiratory illnesses. Carbon monoxide is a colorless, toxic gas produced by incomplete burning of carbon-based fuels and reduces the blood's ability to provide sufficient oxygen to the body. Lead is a metal that is known to have adverse health impacts on the nervous system, kidney function, immune system, reproductive and developmental systems and the cardiovascular system. Inhalation of particulate matter causes and contributes to human respiratory illness.[271]

272. Geronimo's facilities will not produce emissions of hazardous air pollutants (HAPs) or volatile organic compounds (VOCs). Both HAPs and VOCs are known or suspected of causing cancer and other serious health effects.[272]

273. Because Geronimo's facilities will not produce air emissions, their offsetting impacts will result in an annual reduction of 94,133 tons of CO_2, 115.98 tons of CO, 63.26 tons of NO_x, 27.08 tons of PM_{10}, 3.44 tons of VOCs, and 10.48 tons of SO_2.[273]

274. By contrast, each of the gas-powered turbines proposed in this proceeding produces criteria pollutants and CO_2 during the combustion of natural gas.[274]

275. Geronimo's proposed solution will have minimal impacts on the environment. Specifically, Geronimo's facilities will not require water for power

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[268] Minn. R. 7849.0120 (C).

[269] Ex. 38 at 38 (Environmental Report).

[270] *Id. at* 34.

[271] *Id*.

[272] *Id*. at 39.

[273] Ex. 13 at 24 (Distributed Solar Energy Proposal).

[274] *Id.,* at 2.

generation or discharge wastewater containing heat and chemicals during their operation.[275]

276. Geronimo's proposal will produce numerous socioeconomic benefits. In particular, the construction phase of Geronimo's project will include approximately 500 jobs, dispersed in work crews of between 13 and 40 members each. Further, operation and maintenance of its power generation facilities will require up to 10 permanent positions.[276]

277. The wages and salaries from these jobs will contribute to the total personal income in the region and state.[277]

278. Project-related expenditures for materials, equipment, operating supplies and services will benefit businesses located in the host counties and the state. Additionally, landowners who host solar panels or other project facilities will receive annual land payments.[278]

279. Selection of Geronimo's proposal will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including public health.[279]

280. GREs emission levels will be the same whether it effects a sale of capacity credits to Xcel or not.[280]

281. If added capacity is needed beyond 71 MW, selection of GRE's proposal will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including public health.[281]

XXIV. Future Compliance with Applicable Law

282. The fourth criterion under Minn. R. 7849.0120 is whether the proposed resource will comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.[282]

283. Among the proposals in this proceeding, Geronimo's solution best supports Minnesota's move to reduce greenhouse gas emissions across all emission-producing sectors. Minnesota has committed itself to move "to a level at least 15

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275 *Id*. at 23-25 and 32-33.

276 Ex. 38 at 31-33 (Environmental Report).

277 Ex. 13 at 32-33 (Distributed Solar Energy Proposal).

278 *Id*.

279 *See,* Section XXIII.

280 Ex. 63 at 3 (Selander Direct).

281 *See,* Section XXIII.

282 Minn. R. 7849.0120 (D).

percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050." Geronimo's project will not produce greenhouse-gas emissions of its own, and (based on an average system mix needed to generate energy) avoids 94,133 tons of CO2 emissions each year.[283]

284. If the Commission selects Geronimo's proposal, Xcel will use the solar energy produced by the project to meet its requirements under the SES.[284]

285. Geronimo's project will provide approximately 200,000 MWh annually and will make an early and substantial step towards compliance with the new standards.[285]

286. Power plants represent the single largest source of industrial greenhouse gas emissions in the United States and account for approximately 40 percent of all U.S. anthropogenic CO2 emissions.[286]

287. The EPA has proposed a Carbon Pollution Standard for New Power Plants. EPA's proposed standard would set uniform national limits on the amount of carbon pollution new power plants can emit. EPA's proposed standards apply to fossil-fuel-fired boilers, integrated gasification combined cycle (IGCC) units and stationary combined cycle turbine units that generate electricity for sale and are larger than 25 MW. The proposed standards would require covered units to achieve an emission rate of 1000 pounds of CO2 per megawatt hour.[287]

288. Because Geronimo's proposed facilities do not produce CO2 emissions, they pose few risks of higher future costs from more intensive regulation of carbon pollution.[288]

289. Among the proposals in this proceeding, Geronimo's solution represents the lowest risks of non-compliance with state and federal policies, rules, and regulations.

Based on the foregoing Findings of Fact, the Administrative Law Judge makes the following:

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[283] Minn. Stat. § 216H.02, subd. 1; Ex. 13 at 24 (Distributed Solar Energy Proposal).

[284] Ex. 46 at 18 (Wishart Direct); Hearing Transcript, Vol. 1 at 137:4-8.

[285] Ex. 57 at 8 (Engelking Direct).

[286] Table 2-1 from "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009," U.S. Environmental Protection Agency, EPA 430-R-11-005, April 2011.

[287] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22392 (April 13, 2012).

[288] Ex. 13 at 33-39 (Distributed Solar Energy Proposal).

CONCLUSIONS OF LAW

1. The Administrative Law Judge and the Commission have jurisdiction over the subject matter of this hearing pursuant to Minn. Stat. §§ 14.50, 14.57 and 216B.2422, subd. 5.

2. The Commission provided appropriate public notice and all procedural requirements of law and rule have been fulfilled.

3. Under the competitive bidding process, it is the Commission's role to select the most reasonable, prudent resources to meet Xcel's need.

4. It is not clear that there are significant capacity needs on Xcel's system between 2014 and 2018.[289]

5. While Xcel's overall need for additional capacity is uncertain, there is no uncertainty regarding Xcel's need to add solar energy resources to its system.[290]

6. The record in this proceeding indicates that Geronimo's proposal, when properly analyzed under either a LCOE or Strategist modeling, is the lowest cost resource proposed.

7. The most efficient solution in this circumstance is to select scalable projects that meet Xcel's near-term shortfalls (as described in Table 4 of Mr. Wishart's Direct Testimony) and for the Commission to conduct a second procurement for needs which may occur after 2019.

8. The most reasonable and prudent solution in this circumstance is to select scalable projects that meet Xcel's near-term shortfalls (as described in Table 4 of Mr. Wishart's Direct Testimony) and for the Commission to conduct a second procurement for needs which may occur after 2019.

9. Combining Geronimo's proposal with GRE's proposal represents the most reasonable and prudent alternative to meet Xcel's near-term needs.

10. Selection of Geronimo's proposal will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including public health.

11. If added capacity is needed beyond 71 MW, selection of GRE's proposal will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including public health.

12. Selection of Geronimo's proposal is in accord with Minnesota's preferences for low-emission, renewable and distributed generation.

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[289] *See,* Ex. 46 at Table 4 (Wishart Direct).

[290] *See,* Hearing Transcript - Vol. 1 at 149-150.

13. Among the proposals in this proceeding, Geronimo's solution represents the lowest risks of non-compliance with state and federal policies, rules, and regulations.

14. Minn. Stat. § 216B.243, subd. 3(a) prohibits the Commission from issuing a certificate of need for an energy facility that uses nonrenewable fuels unless it can be demonstrated that: (a) the possibility of generating power by means of renewable energy resources was explored, and (b) selection of a renewable energy source to meet the stated need is not in the public interest.

15. The hearing record does not establish that selection of a nonrenewable energy source to meet the first 71 MW of need is in the public interest.

16. Selection of Geronimo's proposal furthers the public interest.

17. If added capacity beyond 71 MW is needed before the end of 2019, selection of GRE's proposal is in the public interest.

18. If the Commission determines that more than 71 MW is needed in 2019, the decision to procure additional resources could safely be postponed until after Xcel's next resource planning process. Assuming a procurement decision is made in early 2017, a natural gas turbine could be constructed and placed into service by late 2018. Similarly, other renewable resources could be placed into service in that same timeframe.

Based upon the foregoing Conclusions, and as detailed further in the Memorandum below, the Administrative Law Judge makes the following:

RECOMMENDATION

IT IS RESPECTFULLY RECOMMENDED that the Commission:

19. Select Geronimo's proposal.

20. Determine if added capacity beyond 71 MW is needed before the end of 2019.

21. Select GRE's proposal if added capacity beyond 71 MW is needed before the end of 2019.

22. Direct Xcel to undertake Purchase Power Agreement negotiations with the selected offerors.

23. Conduct a second competitive bidding process for Xcel's needs beyond 71 MW that are likely to occur after 2019.

Dated: December 31, 2013

ERIC L. LIPMAN
Administrative Law Judge

Reported: Shaddix & Associates, Transcripts Prepared: Two Volumes

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the time frames established in the Commission's rules of practice and procedure, Minn. R. 7829.2700 and 7829.3100, unless otherwise directed by the Commission. Exceptions should be specific and stated and numbered separately. Oral argument before a majority of the Commission will be permitted pursuant to Part 7829.2700, subpart 3. The Commission will make the final determination of the matter after the expiration of the period for filing exceptions, or after oral argument, if an oral argument is held.

The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge's recommendations. The recommendations of the Administrative Law Judge have no legal effect unless expressly adopted by the Commission as its final order.

MEMORANDUM

In this first ever competitive bidding process under Minn. Stat. § 216B.2422, subd. 5, the Commission is presented with a difficult choice: The Commission can either base its resource selection decision upon matters that were certain in 2011 or it can base its selection decision on matters that are certain today. Understandably, the parties split over which set of facts should guide the Commission's decision-making.

In 2011, it was undisputed that: (a) gas-powered turbines were a mature technology for generating electricity and (b) the Commission determined that Xcel's need for additional capacity may be as high as 500 MW in 2019. Highlighting these facts, the Department, Xcel, Calpine and Invenergy urge the selection of one or more thermal units to meet a need that is in excess of 300 MW in 2019.

In 2013, it is undisputed that Xcel: (a) downwardly adjusted its sales and capacity forecasts; (b) is subject to a Solar Energy Standard;[291] and (c) could avoid overbuilding generation facilities by deploying a scalable solution to meet future needs. Highlighting these facts, Geronimo, GRE and Xcel's Super Large Industrial customers urge the selection of scalable alternatives to meet Xcel's more modest capacity needs.

In the view of the Administrative Law Judge, the greatest value to Minnesota and Xcel's ratepayers is drawn from selecting Geronimo's solar energy proposal – and if needed, GRE's short-term capacity credit proposal. In the near-term, these proposals offer competitively-priced energy generation; at firm prices; the fewest new environmental impacts; and significant protections against the imposition of project cancellation costs.

Moreover, while no one in this proceeding confidently predicted that that Xcel would require more than 130 megawatts by 2019, and many suggested the amount is far less, it is certain that Xcel will require significant solar generation resources by 2020. It makes sense to buy the resources that we are certain to need.

Likewise important, the procurement system itself would benefit from the selection of Geronimo's proposal (and if needed, GRE's proposal) in this proceeding. The counter-proposal from the Department, Xcel, Calpine and Invenergy – namely, that the three thermal unit offerors excuse themselves for a set of private price negotiations – was not a feature of the Commission's Notice and Order for Hearing. Segregating these offerors for a set of private talks, *in advance of a selection decision*, would significantly reduce the transparency that this process has displayed so far.

More problematic still, a post-bidding price negotiation among a subset of offerors invites the most destructive kind of "reverse auctions." The public procurement process as a whole suffers when state agencies tell offerors, after their proposals are received, that their "Best and Final Offers" are no longer considered "Best" or "Final." The State of Minnesota benefits most, in the long run, by public procurements that are

291 Minn. Stat. § 216B.1691, subd. 2f.

conducted upon a "level playing field." Changing the rules in the middle of the bidding process is not in the best, long-term interest of Minnesota.

A second, follow-on procurement for those capacity needs which may occur after 2019 would permit the Commission to apply the learning it has gained in this process. For example, among the items that complicated the comparison of proposals in this proceeding was the fact that the Notice and Order for Hearing did not insist upon receipt of fixed prices[292] for a common set of services[293] and interconnection costs.[294]

Accordingly, in the absence of a set of stated minimums on price, packages or extras, the Department and Dr. Rakow simply made assumptions about what those minimums should be. Because the proposals were very different in their size and approach, these assumptions were necessary to an evaluation of the offers.

The problem, of course, is that Dr. Rakow's choices about minimum prices, capacity sizes and interconnection costs are not necessarily the same choices that bidders, in a competitive marketplace, would make. Indeed, the underlying premise of a competitive procurement is that highly-motivated companies will be able to make better and more thorough combinations of bid packages than any agency official could compile from his or her desk.

A second, follow-on procurement should ask bidders (or combinations of bidders) to provide a fixed-priced solution that addresses all aspects of a specific energy capacity problem.

Finally, it bears mentioning that this procurement represents an important turning point in Minnesota's energy resource planning process. Since 1991, Minnesota has had a statutory preference in favor of renewable energy sources. Yet, that preference is overridden when the nonrenewable source has a lower total cost.[295] Notwithstanding the statutory preference, it seemed that nonrenewable energy sources always won the head-to-head cost comparisons. Not anymore. Geronimo entered this bidding process as the sole renewable technology and beat competing offerors on total life-cycle costs. It deserves application of the statutory preference.

For all of these reasons, the best result is for the Commission to select scalable projects that meet Xcel's near-term capacity shortfalls and to conduct a second procurement for needs which may occur after 2019.

E. L. L.

[292] *See, e.g.,* Hearing Transcript, Vol. 1 at 136-37.

[293] *See, e.g.,* Ex. 46 at 25-27 (Wishart Direct); Ex. 83 at 16 (Rakow Direct); Ex. 86 at 3 (Rakow Rebuttal).

[294] *See, e.g.,* Hearing Transcript, Vol. 1 at 135-36 (transmission interconnection costs).

[295] *See,* 1991 Minn. Laws. Ch. 235, Art. 4, § 1.

MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS

600 North Robert Street
Saint Paul, Minnesota 55101

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St. Paul, Minnesota 55164-0620

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December 31, 2013

See Attached Service List

Re: In the Matter of the Petition of NSP Co. d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need

OAH 8-2500-30760
MPUC E-002 / CN-12-1240

To All Persons on the Attached Service List:

Enclosed herewith and served upon you is the Administrative Law Judge's **FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATION** in the above-entitled matter.

Sincerely,

s/Eric L. Lipman

ERIC L. LIPMAN
Administrative Law Judge
Telephone: (651) 361-7842

ELL:km

Enclosure

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
ADMINISTRATIVE LAW SECTION
PO BOX 64620
600 NORTH ROBERT STREET
ST. PAUL, MINNESOTA 55164

CERTIFICATE OF SERVICE

In the Matter of the Petition of NSP Co. d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need	OAH Docket No.: 8-2500-30760

Kendra McCausland certifies that on December 31, 2013 she served a true and correct copy of the attached **FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATION** by eService, and U.S. Mail, (in the manner indicated below) to the following individuals:

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes
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SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need

ISSUE DATE: May 23, 2014

DOCKET NO. E-002/CN-12-1240

ORDER DIRECTING XCEL TO NEGOTIATE DRAFT AGREEMENTS WITH SELECTED PARTIES

PROCEDURAL HISTORY

On March 15, 2011, Northern States Power Company d/b/a Xcel Energy (Xcel) filed a proposal to renovate and increase the capacity of its Black Dog Generating Plant, and requested that the Commission grant a Certificate of Need for the project under Minn. Stat. § 216B.243.[1] Xcel later petitioned to withdraw its application, arguing that subsequent events and new data demonstrated that Xcel would not need additional capacity until after 2014.[2]

On November 21, 2012, the Commission issued an order granting Xcel's petition to terminate its Certificate of Need docket -- but also initiating the current docket to solicit proposals from project developers, and to determine which would best meet Xcel's needs and fulfill the requirements for a Certificate of Need.[3] The Commission took administrative notice of the record in the prior Certificate of Need docket.[4]

On March 5, 2013, in the context of reviewing Xcel's 2011 resource plan under Minn. Stat. § 216B.2422, the Commission issued an order declaring that Xcel had demonstrated the need for an

[1] *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*, Docket No. E-002/CN-11-184, Xcel Petition (March 15, 2011).

[2] *Id.*, Xcel Motion to Withdraw Application (December 7, 2011).

[3] This docket, Order Closing Docket, Establishing New Docket, and Schedule for Competitive Resource Acquisition Process (November 21, 2012).

[4] *Id.*

additional capacity of 150 megawatts (MW) by 2017, increasing up to 500 MW by 2019.[5]

On April 15, 2013, the Commission received proposals from the following parties (bidders):

- Calpine Corporation (Calpine) proposed adding to its Mankato Energy Center a natural gas combustion turbine and a heat recovery steam generator to provide an additional 290 MW of intermediate capacity and 55 MW of peaking capacity.

- Geronimo Wind Energy, LLC, d/b/a Geronimo Energy, LLC (Geronimo), proposed erecting photovoltaic panels at approximately 20 sites adjoining substations along Xcel's transmission or distribution lines, each site with a capacity of 2 to 10 MW, for an aggregate capacity of up to100 MW (or 72 MW of accredited capacity) fueled by solar power.

- Great River Energy (GRE) proposed two alternative packages of resource credits for capacity within the wholesale transmission grid operated by the Midcontinent Independent System Operator, Inc. (MISO), Zone 1 – that is, rights to transmit electricity throughout most of Minnesota as well as areas further east and west.

- Invenergy Thermal Development, LLC, (Invenergy) proposed three 178.5 MW natural gas combustion turbines, one in Cannon Falls and two in Dakota County or Scott County.

- Finally, Xcel's proposed three 215 MW combustion turbine gas generators. One turbine (Black Dog Unit 6) would be installed at Xcel's existing Black Dog Generating Station in Burnsville, and the other two would be built near Hankinson, North Dakota (Red River Units 1 and 2).[6]

On June 21, 2013, the Commission issued an order referring the matter to the Office of Administrative Hearings to conduct a contested case proceeding to develop the record, and to prepare a report and recommendation.[7] The order also asked the Minnesota Department of Commerce (the Department) to prepare an environmental report considering each of the proposals, as well as the alternative of delaying or cancelling all the proposals, but varied some regulatory details governing the preparation of environmental reports.[8]

Administrative Law Judge (ALJ) Eric L. Lipman conducted contested case proceedings, receiving testimony, briefings, or both, from the following participating entities:

- Calpine, represented by Brian M. Meloy and Andrew J. Gibbons from the firm of Leonard, Street and Deinard.

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[5] See *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, Docket No. E-002/RP-10-825, Order Approving Plan, Finding Need, Establishing Filing Requirements, and Closing Docket (March 5, 2013).

[6] If Xcel planned to have Black Dog Unit 6 operational by 2017, it would build it in 2016 and 2017. See Ex. 1 at 1-11 (Xcel Energy Proposal), Ex. 46 at 12 (Wishart Direct).

[7] This docket, Notice and Order for Hearing (June 21, 2013).

[8] *Id.*

- The Department, represented by Julia E. Anderson, Assistant Attorney General.

- Flint Hills Resources, LP; Gerdau Ameristeel Corporation; and USG Interiors, Inc.; (collectively, Xcel Large Industrials) represented by Andrew P. Moratzka from the firm of Stoel Rives LLP.

- Geronimo, represented by Christina K. Brusven from the firm of Fredrikson & Byron.

- Great River Energy, represented by Donna Stephenson, Associate Counsel, and Michael J. Bradley from the firm of Moss & Barnett.

- Invenergy, represented by Eric F. Swanson from the firm of Winthrop & Weinstine.

- Minnesota Center for Environmental Advocacy (MCEA), appeared on behalf of MCEA, Fresh Energy, Sierra Club, and Izaak Walton League - Midwest Office (collectively, the Environmental Intervenors), represented by Kevin Reuther, MCEA Legal Director.

- The North Dakota Public Service Commission Advocacy Staff (NDPSC Advocacy Staff), represented by Ryan M. Norrell, Special Assistant Attorney General for North Dakota.

- Xcel, represented by James R. Denniston, Assistant General Counsel, and Michael C. Krikava, Thomas Erik Bailey, and Kodi J. Church from the firm of Briggs and Morgan.

On July 18, 2013, the Department issued a decision identifying the scope of the environmental report it planned to prepare in this matter (Scoping Decision). The Department proposed to evaluate the option of building no new facility and pursuing any of the alternatives proposed by the bidders to assess each option's consequences for humans and the environment.

On October 14, 2013, the Department issued its environmental report to address the issues identified in the Scoping Decision.

On October 15, 2013, the ALJ convened a public hearing on this matter. And by November 22, the ALJ had received approximately 60 public comments.

On December 31, 2013, the ALJ filed his Findings of Fact, Conclusions of Law, and Recommendation. In response, the Commission received exceptions to the ALJ's report, replies to exceptions, or both, from all the participants other than the NDPSC Advocacy Staff.

On March 25 and 27, 2014, the Commission met to consider the matter. The Commission received comments from all participants other than the NDPSC Advocacy Staff.

FINDINGS AND CONCLUSIONS

I. Summary

Assuming Xcel and the selected bidders can agree to terms that are consistent with the public interest, the Commission finds as follows:

- Geronimo's proposal provides an appropriate choice for meeting a portion of Xcel's reliability and adequacy needs, and to fulfill the state's energy policies.

- Calpine's proposal, Invenergy's Cannon Falls proposal, and Xcel's Black Dog proposal may also provide appropriate choices for Xcel to meet a portion of its reliability and adequacy needs and to fulfill the state's policies.

Consequently the Commission directs Xcel to finalize draft power purchase agreements with Geronimo, Calpine and Invenergy, and to draft finalized cost estimates for Xcel's Black Dog Unit 6 proposal that would be binding on Xcel, and to submit these finalized terms for Commission review.

The Commission also makes a number of findings in support of these conclusions.

Finally, as a procedural matter, the Commission directs Xcel to file annual progress reports and extends the filing date for Xcel's next resource plan to January 2, 2015.

II. Background

A. Resource Planning

Minn. Stat. § 216B.2422 directs larger electric utilities to disclose both their plans, and the analysis underlying the plans, for selecting the resources necessary to meet customer demand throughout the next 15 years.

Planning begins with a forecast of the demand for electricity within the utility's service area. In particular, a utility must forecast the maximum amount of electricity it must provide at any one time – that is, its peak demand. The utility must then design its system to ensure that it has enough resources to meet this maximum peak, plus some extra resources to address unanticipated circumstances – such as unexpectedly high demand, or unexpected resource outages.

The utility then evaluates resources it might use to meet its needs. The utility can supply electricity through a combination of generation and power purchases. The utility can also 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 supply-side and demand-side resource options that the utility could use to meet the needs of retail customers. A utility considers the supply-side and demand-side resources together on an integrated basis. Through the process of creating an integrated resource plan, a utility can identify the least-expensive reliable combination of resources that will meet the utility's requirements, consistent with state and federal law and public policy.

When identifying the optimal mix of supply-side resources, a utility considers the different benefits offered by the different types of generators. Baseload generators are designed to operate almost continuously; they tend to have low operating costs but may be relatively expensive to build. Peaking generators are designed to operate only under rare periods of peak demand for electricity; these generators tend to be less expensive to build, but may have higher operating costs. And intermediate generators are designed to run more frequently than peaking generators but less frequently than baseload generators; intermediate generators tend to have lower construction costs than baseload generators and lower operating costs than peaking generators.[9]

B. Laws and Policies Influencing Resource Planning

Among the legal requirements and policies influencing Xcel's resource plan are the following:

- Renewable Energy Standard: Minn. Stat. § 216B.1691 directs Xcel to acquire electricity from renewable sources sufficient to meet 30 percent of the needs of its retail customers by 2020.[10]

- Solar Energy Standard: In 2013 the Legislature added the Solar Energy Standard, directing investor-owned utilities such as Xcel to acquire sufficient electricity from solar energy to supply 1.5 percent of the utility's total retail electric sales (excluding sales to certain industrial customers) by 2020.[11] Xcel estimates that by 2020 compliance would require 455,919 megawatt-hours (MWh) of solar energy,[12] or up to 200 MW of accredited capacity.[13]

- Greenhouse Gas Regulation: Minn. Stat. § 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.[14] And Minn. Stat. § 216H.02, subd. 1, declares the state's goal to reduce statewide greenhouse gas emissions relative to 2005 levels by at least 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050. And Minn. Stat. § 3.8852 commissions a framework for making Minnesota the first state in the nation to use only renewable energy.

- 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 associated with each method of electricity generation," and to use those costs for purposes of comparing resource alternatives.

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[9] See, for example, Public Hearing Transcript, Vol. 1 at 11-12 (testimony of Xcel witness Alders).

[10] Minn. Stat. § 216B.1691, subd. 2a(b)(4).

[11] Minn. Stat. § 216B.1691, subd. 2f; see 2013 Laws of Minnesota, Ch. 85, Art. 10, § 3.

[12] ALJ's Report, Finding 14, citing Ex. 57 at 8 (Engelking Direct), citing Xcel Comments, *In the Matter of the Request for Filings From Electric Utilities on Customers Excluded From the Solar Energy Standard*, Docket No. E-999/CI-13-542 at 4 (August 15, 2013).

[13] Ex. 83 at 19 (Rakow Direct).

[14] 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.

- Certificate of Need: To build a new large energy facility powered by nonrenewable fuels in Minnesota, generally a developer must demonstrate that the generator is needed, and that relying on a generator powered by renewable energy sources would result in higher cost – including environmental costs – and would not otherwise be in the public interest.[15] In evaluating need, the Commission considers whether --

  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. 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…; 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.[16]

C. The Midcontinent Independent System Operator, Inc. (MISO)

The Midcontinent Independent System Operator, Inc. (MISO), administers the wholesale electric transmission grid in 15 states plus Manitoba. It divides its operations into regional zones. Zone 1 includes nearly all of Minnesota, as well as parts of the states to the east and west.

MISO ensures the reliability of the electric system within its boundaries by guarding against the possibility of load-serving entities – generally, utilities -- having insufficient resources to meet the needs of their customers. As part of this effort, MISO considers both supply and demand.

MISO considers supply when it credits a generator's capacity. First, generators have *installed capacity* stating how much power the generator is designed to produce under optimal conditions. But conditions are not always optimal. For example, Xcel concedes that its proposed 215 MW combustion turbines would achieve a maximum output of only 208 MW during summer heat and humidity.

Further, MISO calculates the actual expected capacity of generators within its region – that is, the unforced accredited capacity. Under MISO's accreditation formula, neither intermittent, renewable generators nor dispatchable gas-powered generators would receive 100 percent accreditation of its installed capacity when determining resource adequacy. Using MISO's formula, Geronimo determined that the expected MISO accredited capacity of its solar resource would be 72 percent.

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[15] Minn. Stat. §§ 216B.2422, subd. 4; 216B.243, subd. 3a.

[16] Minn. R. 7849.0120.

MISO considers demand in setting reserve requirements – that is, access to generation capacity that is in excess of that utility's forecasted peak energy demand.[17] Reserve requirements serve as insurance against the possibility of unanticipated customer demand (due to hot weather, for example) or unanticipated outages (due to a generator's mechanical failure, for example).

In 2012 MISO set a utility's reserve requirement equal to 3.79 percent – the planning reserve margin -- of the greatest level of demand that the utility's customers put on its system.[18] But starting in 2013 MISO changed this formula in two ways. First, the new formula no longer reflected a *utility's* peak demand, but rather the level of demand on the utility's system during the hour of *MISO*'s peak demand. Second, the new formula changed the planning reserve margin from 3.79 percent to 6.2 percent for 2013, and to 7.3 percent for 2014.[19]

In lieu of holding its own generator out of service to meet its reserve requirement, a utility may acquire Zone Resource Credits. These credits, such as the ones offered by GRE, count towards MISO reserve requirement but cannot be used to meet a utility's energy demand.[20]

D. Xcel's competitive resource acquisition process

To help Xcel acquire the best resources at least cost, the Commission established a competitive resource acquisition process under Minn. Stat. § 216B.2422, subd. 5.[21] The Department has summarized the operational details.[22] But in general, when Xcel proposes to submit its own bid as part of the competition, the process includes the following steps:

- Under Commission direction, Xcel publicizes the amount of capacity it needs and the timeframe in which Xcel needs it, and solicits proposals for meeting that need.

- Project developers, including Xcel, file proposals for meeting some or all of Xcel's need.

- The Commission determines which proposals to accept as substantially complete and suitable for evaluation.

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17 See, for example, Ex. 46 at 5 (Wishart direct) (defining "reserve margin").

18 ALJ's Report, Finding 174, mistakenly attributes the source of this formula to Xcel rather than MISO.

19 Ex. 83 at 22 – 25, 39 (Rakow Direct); Ex. 44 at 7-11 (Wishart Direct); Environmental Intevenors' Reply to Exceptions at 10 (noting results of MISO's 2014 Loss of Load Expectations Study establishing 7.3 percent unforced capacity planning reserve margin).

20 Environmental Report at § 3.5.

21 See *In the Matter of Northern States Power Company d/b/a/ Xcel Energy's Application for Approval of its 2004 Resource Plan, Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, subd. 5, and Requiring Compliance Filing*, Docket No. 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).

22 *Id.*, Docket No. E-002/RP-04-1752, Department reply comments (January 30, 2006); see also this docket, Order Approving Notice Plan (January 30, 2013).

- If there are material facts in dispute, the Commission refers the matter to the Office of Administrative Hearings for a contested case before an ALJ. The ALJ conducts evidentiary hearings and prepares a report recommending a course of action.

- The Commission reviews the record of the case, including the ALJ's report. The Commission then identifies the resources that are best supported by the record.

- If the Commission selects an option not proposed by Xcel, then within four months Xcel must negotiate a power purchase agreement and submit it for Commission approval, or provide an explanation for its failure to do so and a recommendation for how to proceed.[23]

The developer of a project chosen through a Commission-approved competitive resource acquisition process is exempt from the requirement to secure a Certificate of Need.[24] Nevertheless, when Xcel offers a proposal as part of its competitive resource acquisition process, the Commission subjects the proposals to the scrutiny of a Certificate-of-Need-like proceeding.[25]

III. Environmental Report

When a party proposes to build a large energy generating facility requiring a Certificate of Need, Minn. R. 7849.1200 directs the Department to prepare an environmental report examining the project's potential consequences for humans and the environment, alternatives to the project, and potential measures for mitigating any anticipated harms. This rule was adopted to implement Minn. Stat. § 116D.04.

In preparing an environmental report, the Department proposes a scope of matters to address in the report, receives comments on this scope, and issues a final order establishing the report's scope. Then the Department drafts and issues a report consistent with its proposed scope.

On July 18, 2013, the Department issued a decision identifying the scope of the environmental report it planned to conduct in this matter. The Department proposed to evaluate the option of pursuing each of the alternatives proposed by the bidders, and the option of building no new facility at all, to assess each option's consequences for humans and the environment. And the Department identified 18 categories of consequences it would explore – for example, traffic, noise, and economic impacts.

On October 14, 2013, the Department issued its four-volume environmental report, comparing the alternatives to each other with respect to 18 types of environmental consequences.

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[23] *Id.*, Docket No. E-002/RP-04-1752, Xcel compliance filing (August 28, 2006) at 5 – 6.

[24] Minn. Stat. § 216B.2422 subd. 5(b).

[25] Docket No. E-002/RP-04-1752, May 31, 2006 Order at 7; Xcel Compliance Filing at 5 (August 28, 2006).

IV. Analysis of Proposals

A. Establishing a "Level Playing Field"

Each bidding party completed a form identifying the relevant costs and benefits of its proposal. Next, the Department reviewed these forms to determine if the parties were making disclosures and estimates on a comparable basis. For example, the Department analyzed the transmission-related issues attributable to each proposal and ensured that all transmission costs were included in each bid.[26] At the Department's request, Calpine disclosed that its proposal would require upgrades to the transmission system at a cost MISO estimated to be between $650,000 and $1.5 million. The Department calculated that this additional cost would translate into a present value of revenue requirement of $1.55 million and adjusted the results of its analysis accordingly.

In this manner, the Department sought to ensure that the proposals would be compared on the merits of their proposals rather than on disagreements about the meaning of the data.

B. Analytical Models

1. Levelized Cost of Electricity Model

The Levelized Cost of Electricity represents the net present value of the expected annual costs – including variable and fixed operations and maintenance costs, capital costs and the return on investment – divided by annual generation over the term of the proposal.[27] Calpine relied on the Levelized Cost of Energy model in developing it case.

Calpine's analysis found its proposal to be the least-cost gas-powered proposal. However, Calpine acknowledged the limitations of the Levelized Cost of Electricity model in choosing not to compare gas-powered generators to Geronimo's or GRE's proposals.

2. Strategist Capacity Expansion Model

The Strategist capacity expansion model identifies the set of resources for a given system that would provide the least cost method to meet increases in demand.[28] The Department, Invenergy, and Xcel argue that a capacity expansion model is the appropriate tool for comparing the proposals in this docket. Calpine cautions, however, that the mechanisms of this model are proprietary and thus not subject to scrutiny.[29]

Employing the Strategist model, the Department conducted three rounds of analyses. In the first round the Department used data supplied by the bidders themselves to identify every possible combination of proposals that would provide less than 700 MW. This resulted in a total of 153

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[26] Ex. 81 at CJS-5 at 8 (Shaw Direct Attachments); Ex. 79 at 5 (Shaw Direct).

[27] ALJ's Report, Finding 254, citing Ex. 52 at 6 (Hibbard Direct).

[28] Ex. 52 at 5 and 14, n.4 (Hibbard Direct).

[29] *Id*. at 7.

packages of proposals, including the base case as a “no build” alternative.[30]

The Department analyzed how each package would perform under a variety of circumstances.[31] Through this analysis the Department identified the seven least-cost packages of proposals, with the lowest cost attributed to a combination of Calpine’s Mankato proposal with Xcel’s Black Dog Unit 6 proposal. Given the size of this package of generators, however, the Department also analyzed the effects of deploying smaller energy solutions and of changing the dates on which the generators would begin operations.[32]

To compare proposals of very different sizes, the Department allowed Strategist to add generic generators to its modeling of particular bid packages; this technique permits the model to illuminate how the cost to Xcel’s system of any given package would compare to the cost of any other package over the generators’ useful lives. Xcel estimated the cost of a generic gas-powered or solar-powered generator based on the estimated current cost to build a particular type of generator, escalated over time for inflation.[33]

The Department then performed a second round of analysis on the seven least-cost packages of proposals from the first round -- plus a Base Case package that involved adding no new capacity – to evaluate these alternatives under a greater variety of scenarios.[34] This round again identified a least-cost package that included Calpine’s proposal with Xcel’s Black Dog Unit 6 proposal. Even when considering the high demand forecasts from Xcel’s resource plan, the Department estimated that these projects would meet Xcel’s power needs until 2023 – and even longer if the more recent demand forecasts prove more accurate.[35]

In its third round of analysis, the Department considered how the various packages would perform under differing types of gas supply contracts, or if implementation dates were shifted. This final round of analysis also identified a package including Calpine’s Mankato proposal and Xcel’s Black Dog Unit 6 proposal as having least cost. But this analysis also identified Invenergy’s Cannon Falls proposal as a component of many of the top packages, depending on whether the model assumed this proposal would include the cost of a firm or interruptible gas supply.

Based on this analysis, the Department recommended that the Commission authorize Xcel to

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30 Ex. 83 at 17 (Rakow Direct).

31 ALJ’s Report, Finding 171, citing Ex. 83 at 22 – 25 (Rakow Direct). This analysis did not consider new planning reserve margin of 7.3 percent.

32 Ex. 83 at 36-37 (Rakow Direct). Contrary to the ALJ’s Report, Finding 219, the Department’s analysis was prompted by the combined size of both generators, not just of Black Dog Unit 6. See Department Exceptions.

33 *See, e.g.,* Hearing Transcript, Vol. 1 at 109-110.

34 Ex. 83 at 36-40 (Rakow Direct). While the second round did not model the consequences of raising MISO’s reserve requirement to 7.3 percent, Dr. Rakow states that he considered this factor in reviewing the Strategist model outputs.

35 ALJ’s Report, Finding 223, citing Ex. 83 at 40 and 43 (Rakow Direct); Ex. 84 SR-5A (Rakow Direct Attachments).

negotiate with Calpine, Invenergy, and Xcel to finalize terms, including terms regarding the type of gas supply contracts and in-service dates, and to approve contracts with two of the three. The Department did not find Geronimo's proposal to be cost competitive with these other three.

Xcel's Strategist modeling differed in certain respects from the Department's analysis, and identified its Black Dog Unit 6 as the least-cost resource.[36]

V. ALJ's Report

After convening hearings and receiving briefs and reply briefs, the Administrative Law Judge issued his report on December 31, 2013.

A. Demand

In evaluating which source of electric capacity would best meet Xcel's needs, the ALJ started by examining the extent of that need. The Commission found that Xcel had demonstrated need for 150 MW by 2017, and potentially up to 500 MW by 2019 – but the Commission had reached this conclusion in 2013 based on Xcel's 2011 resource plan filing. The ALJ was prompted to reassess the Commission's conclusion based on more recent developments – including the following:

First, the Legislature adopted the new Solar Energy Standard.[37] While this statutory change does not alter Xcel's demand, it arguably reduces the portion of the demand that Xcel should seek to meet through sources other than solar power.

Second, in September 2013 Xcel issued a lower demand forecast based on new data. Rather than finding a need for an additional 150 MW in 2017, increasing up to 500 MW by 2019, Xcel found a need for only 93 MW by in 2017, increasing to 307 MW in 2019.

Third, MISO changed the manner in which it calculates reserve requirements. In 2012 MISO required Xcel to maintain a reserve margin calculated on the basis of Xcel's peak demand. But MISO recently changed its formula to require Xcel to calculate its reserve requirement on the basis of Xcel's demand *during the hour of MISO's system peak demand* rather than at the time of Xcel's peak demand.[38]

Demand on the MISO system typically peaks at a different time than on Xcel's system; in other words, demand on Xcel's system during MISO's peak is typically lower than during Xcel's peak. The ALJ found that between 2006 and 2012, customer demand on Xcel's system was 5 percent lower than during MISO's peak times.[39] And the ALJ cited Xcel witness Steven Wishart for the proposition that MISO's formula reduced Xcel's reserve requirements by approximately 200 MW.

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[36] ALJ's Report, Finding 218.

[37] Minn. Stat. § 216B.1691, subd. 2f.

[38] Ex. 83 at 22-24 (Rakow Direct).

[39] Ex. 46 at 8-9 and Table 3 (Wishart Direct).

The ALJ further found that the combined effects of various changes show that Xcel will not need additional capacity until 2019, when Xcel will need to add a mere 26 MW.[40]

Given this degree of uncertainty, the ALJ found it prudent to pursue a flexible strategy of selecting one or more projects susceptible to delay and size changes. And rather than make irreversible investments to meet an uncertain demand, the ALJ recommended erring on the side of acquiring fewer or smaller resources now, and preparing to solicit bids for additional resources in the future.

B. Supply

Considering a variety of criteria, the ALJ ultimately recommended that the Commission direct Xcel to contract for Geronimo's proposed solar-powered generators and to prepare to solicit bids for generators needed in 2019 and later, pending the outcome of Xcel's next resource plan.

The ALJ found that Geronimo's proposal had a variety of advantages, including the following:

- The Geronimo project is relatively small, making it a good match for the modest demand needs revealed by Xcel's latest demand forecast.

- Applying two analytical models – Levelized Cost of Electricity and the Strategist capacity expansion model – and adjusting for relevant factors, the ALJ concluded that Geronimo's project provided electricity at the least societal cost.

- The Legislature has determined that Xcel must acquire more solar-powered electricity in any event.

- Future environmental regulations are unlikely to cause Geronimo's proposal to incur unforeseen costs or face unforeseen delays.

- The Certificate of Need statute directs the Commission to select generators fueled from renewable sources unless the Commission can find that doing so would be contrary to the public interest. Geronimo proposed the sole generator to be fueled from a renewable source. Given the factors listed above, the ALJ could not determine that selecting the Geronimo project would be contrary to the public interest.

The ALJ faulted the Department's analysis of Geronimo's proposal. According to the ALJ, the Department's analysis failed to acknowledge that the proposal would permit Xcel to avoid the cost of securing at least 72 of the megawatts required to fulfill the Solar Energy Standard.[41] Alternatively, the Department failed to recognize that the proposal would supply Xcel with valuable solar renewable energy credits (S-RECs):

> At a price of $5 for each marketable S-REC, the Geronimo proposal will result in a PVSC [present value of societal costs] reduction of $10 million annually. At a price

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[40] ALJ's Report, Findings 24 - 25, citing Ex. 46 at 2, 10 (Wishart Direct).

[41] *Id.*, Finding 153.

of $20 for each marketable S-REC, the Geronimo proposal will result in a PVSC reduction of $38 million annually.[42]

The ALJ also concluded that the manner in which the Department and Xcel conducted their Strategist modeling biased the results they obtained. According to the ALJ, the Department and Xcel instructed the Strategist model to evaluate combinations of generators that could produce 300 MW by 2019, or 11 times the forecast demand of 26 MW.[43] This arbitrary choice had the effect of obscuring the benefits of smaller proposals that are well-designed to meet the lower demand level, the ALJ concluded. He further found that this threshold obscured the merits of Calpine's proposal. Calpine proposed a 278 MW generator. Because it failed to meet the 300 MW threshold, the Department and Xcel would only consider its performance when it was combined with another generator. This is because, as configured by the Department and Xcel, whenever the Strategist model identified a shortfall in generation, even as small as 1 or 2 MW, the model would select the next full plant to meet the added need.[44]

The ALJ also found that GRE's proposed transmission capacity credits provided a reasonably-priced, flexible source of capacity. If the Commission were to find that Xcel would need more than 72 MW before the next round of generators could be selected and built, the ALJ would recommend authorizing Xcel to acquire GRE's credits.

C. Certificate of Need Criteria

Because the Commission had stated that this competitive resource acquisition process would use the analytical framework of the Certificate of Need process, the ALJ analyzed the proposals to identify the ones that best fulfill the criteria to receive a Certificate of Need.

1. Effect on Electric Supply's Future Adequacy, Reliability, or Efficiency

Minn. R. 7849.0120.A. addresses how the choice of resource might affect the future adequacy, reliability, or efficiency of energy supplied to the utility, its customers, and the people of Minnesota and neighboring states. While the Commission had identified Xcel's need for 150 MW by 2017 and up to 500 MW by 2019, the ALJ found that the record demonstrated the need for no new capacity in 2017 and 2018, and only 26 MW by 2019.[45]

The ALJ then evaluated each party's proposals based on how efficiently the proposal would meet this limited need. The ALJ concluded that all of the proposed gas-powered proposals were too large for the identified need.[46]

In contrast, the ALJ found that Geronimo's proposal has many advantages. Solar-powered generators tend to produce their maximum output during sunny daylight hours of summer – which

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[42] *Id.*, Finding 156, citing Ex. 59 at 18-19 and Table 2 (Engelking Rebuttal).

[43] *Id.*, Finding 181–183.

[44] *Id.*, Finding 184, citing Hearing Transcript, Vol. 1 at 105; *see also*, Ex. 83 at 16 (Rakow Direct).

[45] *Id.*, Finding 239, citing Ex. 46 at 8-10 and Table 4 (Wishart Direct).

[46] *Id.*

coincides with the period of peak demand for electricity.[47] Geronimo's proposal contains a variety of features designed to promote its reliability.[48] Moreover, 72 MW of distributed generation – that is, a fleet of generators disbursed throughout a service area – has advantages over a comparably-sized generator at a single, remote location: Reliability is enhanced, the ALJ found, because a technical failure is unlikely to affect more than a single generator at a time.[49] And because the generators would tend to be located in proximity to customers, Xcel would lose less electricity in transmission, and require less transmission and distribution capacity.[50]

Additionally, the ALJ found that GRE's proposal – the sale of MISO capacity credits – has the advantage of making off-the-shelf capacity available on very flexible terms.[51]

2. Reasonableness and Prudence

Minn. R. 7849.0120.B. seeks to identify the most reasonable and prudent alternative demonstrated on the record. The ALJ concluded that the appropriate tool for identifying this alternative is a Levelized Cost of Electricity analysis.[52]

Partially on this basis, the ALJ identified the Geronimo proposal – potentially supplemented with the GRE proposal -- as the most reasonable and prudent alternative.[53] The ALJ found that on a per MWh basis, Geronimo's proposed solar-powered generator is the lowest cost stand-alone resource.[54] And unlike other types of capacity, Geronimo's proposal helps Xcel meet its Solar Energy Standard obligation, reduces transmission capacity costs and transmission line-loss costs, and creates no cost for fuel or emission controls -- nor the risk of these costs increasing over time.[55]

The ALJ rejected the analyses of other parties on the theory that they had 1) placed undue reliance on the demand forecast from Xcel's resource plan, 2) overlooked many of the benefits of the Geronimo proposal, and 3) failed to consider optimal strategies for meeting needs less than 300 MW. In addition, the ALJ concluded that other analyses failed to give sufficient value to the flexible scope of the Geronimo and GRE proposals. If Xcel were to commit to a project with a fixed generating capacity, and the anticipated level of demand did not materialize to justify a project of that size, Xcel would lack the option of scaling back the project – and would be stuck bearing cancellation costs instead.

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[47] *Id.*, citing Ex. 60 at 12-13 and 15-16 (Beach Direct).

[48] *Id.*, Finding 241, citing Ex. 60 at 3-5 and 18-19 (Beach Direct); Ex. 62 at 4 (Skarbakka Direct).

[49] *Id.*, Finding 243, citing Ex. 62 at 3-4 (Skarbakka Direct).

[50] *Id.*, Finding 244, citing Ex. 13 at 31 (Distributed Solar Energy Proposal); Ex. 61 at 7 (Beach Rebuttal).

[51] ALJ's Report, Findings 246-248, citing Ex. 63 at 2-3 (Selander Direct), Ex. 64 at 3 (Selander Rebuttal).

[52] *Id.*, Findings 253-254, citing Ex. 52 at 6-7 (Hibbard Direct).

[53] *Id.*, Finding 259.

[54] *Id.*, Finding 257, citing Ex. 74 at 7 (Norman Rebuttal).

[55] *Id.*, Finding 256, citing Ex. 13 at 19 (Distributed Solar Energy Proposal).

3. Benefits Compatible with Nature, Society, and Health

Minn. R. 7849.0120.C. seeks to identify projects that would provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health.

The ALJ found that the construction and operation of Geronimo's proposal, unlike the gas-powered proposals, would avoid generating a variety of pollutants, or even using much ground water.[56] The ALJ also found that Geronimo's proposal would generate a variety of temporary and permanent jobs, and other economic activity.[57]

4. Compliance with Laws of Other Jurisdictions

Minn. R. 7849.0120.D. asks whether the record demonstrates that the design, construction, or operation of a proposed facility, even if suitably modified for the purpose of complying with all relevant policies, rules, and regulations of other state and federal agencies and local governments, would nevertheless fail to comply. Citing examples of federal and state policies seeking to reduce emissions of greenhouse gases such as carbon dioxide (CO_2), the ALJ reasoned that Geronimo's proposal – the only proposal that would generate electricity without generating greenhouse gases – would pose the least risk of violating these policies, or of incurring additional compliance costs.[58]

D. Conclusions

Based on his findings, the ALJ concluded as follows: First, the record does not support the need for Xcel to acquire more than 26 MW by 2019 via this docket. Consequently the ALJ recommended selecting scalable projects to meet this near-term need, and addressing later resource needs via a later resource acquisition process.[59] Even a finding of much greater need in 2019 would not justify making those decisions in the current docket.

Second, as between the two scalable proposals – Geronimo's and GRE's – the ALJ concluded that Geronimo's proposal is cheaper, as reflected in both the Strategist and Levelized Cost of Electricity models when adjusted to incorporate all the desirable features of Geronimo's proposal (S-RECs, reliability, reduced transmission and distribution costs, etc.). Consequently the ALJ recommended selecting Geronimo's project to fulfill up to the first 72 MW of need, and initiating negotiations to finalize a power purchase agreement. If the Commission were to find additional need, the ALJ would recommend selecting GRE's proposal.

VI. Positions of the Parties and Participants

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[56] Ex. 13 at 24, 34 (Distributed Solar Energy Proposal); Ex. 38 at 38 (Environmental Report).

[57] ALJ's Report, Finding 276, citing Ex. 38 at 31-33 (Environmental Report).

[58] *Id*., Findings 283-289, citing, for example, Minn. Stat. § 216H.02, subd. 1; Ex. 13 at 24 (Distributed Solar Energy Proposal).

[59] *Id*., Finding 249, citing generally Ex. 46 at 8-10 and Table 4 (Wishart Direct).

A. The Department

The Department took exception to various aspects of the ALJ's Report, and to its conclusion.

Demand forecast: While the ALJ developed his analysis on the basis of Xcel's 2013 demand forecast, the Department developed its analysis based on Xcel's 2011 forecast. Justifying this choice, the Department states that it has not verified the accuracy of Xcel's spring 2013 forecast and had significant concerns about how to interpret the results. Moreover, the Department argues that the Commission relied on the 2011 forecast as the basis for soliciting proposals from the parties, and the parties relied on this forecast in fashioning their proposals.[60] In any event, the Department notes that its analysis explored how the proposed resources would perform under a variety of demand levels – including the level of demand indicated by Xcel's 2013 forecast. Consequently the Department argues that the scope of its analysis encompassed the new data, even if it was not specifically designed around that data.

Level playing field: As previously discussed, the Department strove to ensure that the proposals would be compared on an equivalent basis. This task is complicated by the fact that much of the information about a proposal comes from the party proposing it. One way to promote a fair outcome, the Department argues, is to ask parties to bear the consequences of their statements. If a bidder stated that its proposal would provide certain benefits or avoid specified costs, and the Commission selects that proposal, the Department reasons that the bidder should bear any economic consequence of failing to conform to the terms of its bid. Consequently the Department plans to oppose a power purchase agreement for any project that would shift more costs to ratepayers than were reflected in the Department's analysis of the project.[61]

While Geronimo claims that its proposal would produce valuable S-RECs, or would help offset transmission congestion, Geronimo did not put those claims into its initial bid. Consequently the Department has not included those considerations in its modeling. Moreover, the Department and Xcel elected to exclude transmission interconnection-related factors from the analysis of each of the proposals, so the Department declined to consider Geronimo's claims related to transmission costs.

Capacity expansion model vs. Levelized Cost of Electricity model: While the ALJ relied primarily on a Levelized Cost of Electricity analysis, the Department favors reliance on the Strategist capacity expansion model.

Modeling details: Many of the Department's exceptions pertained to the ALJ's review of the Department's Strategist model.

For example, the ALJ's Report criticizes the Department for excluding consideration of generators, and combinations of generators, that produced less than 300 MW in 2019, an amount more than 11 times as large as the forecasted need of 26 MW, thus adding an additional generator to any package of generators that produced less than 300 MW – even if the package produced 299 MW. The Department identifies a variety of flaws in this analysis.

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[60] Ex. 76 at 8 - 14 (Shah Direct).

[61] Ex. 82 at 4 -5 (Shaw Rebuttal).

As an initial matter, the Department rejects the forecast suggesting that Xcel will not need more than 26 MW by 2019, and thus rejects the conclusions that flow from it.

Moreover, while this part of the ALJ's Report may accurately characterize aspects of Xcel's modeling, it fails to reflect the complexities of the Department's. In its first round of Strategist analysis the Department considered 24 different combinations of forecasts, solar accreditation, reserve margins, and wind additions, resulting in varying levels of need. In its second round, the Department's *base case* conditions resulted in an analysis of a 300 MW need by 2019. However, this round also analyzed various contingencies, again resulting in the consideration of a variety of levels of need.[62] Thus it is not accurate to say that the Department's modeling failed to consider combinations of generators producing less than 300 MW.

However, the Department acknowledges that it directed Strategist to develop packages of generators that are sufficient to meet the need demanded within any given scenario, and not a MW less. This practice is consistent with long-standing Commission decisions regarding how to use the wholesale market to ensure that utilities are able to provide reliable service.[63]

According to the Department, the ALJ's Report erred in adopting Geronimo's claim that Xcel and the Department used the same base assumptions regarding the cost of generic generators. The Department clarified that it and Xcel employed different assumptions regarding the modeling of solar generators, and how they induced the Strategist model to reflect the requirements of the Solar Energy Standard.[64]

The ALJ found that the Department's practice of comparing generators by packaging them with generic generators entails some risk of biasing the results of the analysis, especially if the estimated costs of the generic generators are too high or low.[65] The Department acknowledges this risk, but explains that the risk is managed through analyzing packages under a variety of assumptions about capital costs.[66]

Because the cost of the bidders' gas-powered proposals were lower than the estimated costs of comparable generic generators, whereas the cost of Geronimo's solar-powered proposal was higher than the estimated cost of generic solar-powered generators, the ALJ found that the Department's analysis advantaged gas-powered proposals and disadvantaged Geronimo's proposal.[67] The Department argues that this finding reflects a misunderstanding of its model.

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62 Ex. 46 at 10-11 (Wishart Direct); Ex. 84 SR-3 and SR-4A (Rakow Direct Attachments).

63 Hearing Transcript, Vol. 1 at 105; *see also,* Ex. 83 at 19 (Rakow Direct). While MISO is in the process of establishing a wholesale capacity market, the Department and Xcel excluded this option from their modeling.

64 Ex. 59 (Engelking Rebuttal, Schedule EME-3); Hearing Transcript, Vol. 1 at 110; Ex. 83 at 19 (Rakow Direct).

65 ALJ's Report, Findings 190 and 191.

66 Ex. 83 at 36-37 (Rakow Direct).

67 ALJ's Report, Findings 192 and 193.

Rather, the Department emphasizes that the Strategist model ranked *packages* of generators. Smaller proposals – such as Geronimo's proposal – would be packaged with relatively more generic generators. If these generic generators had lower costs than the proposal, they would tend to bring *down* the average cost of the package, and thus *boost* the package's ranking in the Strategist model.[68]

The ALJ's Report faults the Department's analysis for ignoring the value of the solar renewable energy credits that Geronimo's proposal would generate. These credits would permit Xcel to fulfill part of its obligations under the Solar Energy Standard – or simply provide a valuable asset to sell, according to the ALJ:

> At a price of $5 for each marketable S-REC, the Geronimo proposal will result in a PVSC reduction of $10 million annually. At a price of $20 for each marketable S-REC, the Geronimo proposal will result in a PVSC reduction of $38 million annually.[69]

The Department denies that it simply overlooked the option of incorporating into its model the idea that Geronimo's proposal would permit Xcel to avoid certain capacity, energy, or costs needed to comply with the Solar Energy Standard. Rather, the testimony of Dr. Steve Rakow sets forth the Department's reasons for declining to include these factors in its modeling. Dr. Rakow also described how to interpret the Department's modeling results to impute to Geronimo's proposal the benefits of reducing the capacity and energy costs of complying with the Solar Energy Standard. In any event, the Department built its analysis around the assumption that Xcel would comply with the Solar Energy Standard by 2020; because Xcel cannot sell a given S-REC and also use it to comply with the Solar Energy Standard, the Department's analysis fully accounts for the value of these credits.[70]

Regarding the value of the S-RECs to be generated by Geronimo, the Department clarified that the figure cited by the ALJ reflected estimates of the *total* value of credits generated by the project over its lifetime, not the *annual* amounts. Moreover, the Department noted that these estimates were generated assuming that the generating capacity of solar cells remain constant throughout their service lives. In contrast, the record shows that their generating potential degrades over time.[71]

The ALJ's Report accepted Geronimo's claim that, when the Department and Xcel calculated the present value of the societal cost of Geronimo's proposal, they should have reduced this figure by approximately $9 million to reflect the fact that Geronimo proposes to generate electricity near to

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[68] Ex. 59 (Engelking Rebuttal, Sch. EME-3); Ex. 83 at 30 (Rakow Direct); Hearing Transcript, Vol. 1 at 110. This dynamic did not apply to the manner in which Xcel conducted its Strategist analysis. Ex. 46 at 36 (Wishart Direct).

[69] ALJ's Report, Finding 156, citing Ex. 59 at 18-19 and Table 2 (Engelking Rebuttal).

[70] Ex. 83 at 9-13 (Rakow Direct).

[71] Ex. 59 at 18-19 and Table 2 (Engelking Rebuttal).

customers' locations, thereby reducing the amount of energy lost in transmission.[72] But the Department explains that Xcel could not verify Geronimo's calculation due to Geronimo's failure to identify the proposed locations of its generators.[73] Consequently the Department declined to make this type of adjustment for any of the proposals. In any event, the Department noted that Geronimo's proposal exceeded the cost of rival proposals by substantially more than $9 million, and thus this adjustment would not have altered the Department's assessment.

The ALJ's Report found that some of Geronimo's proposed generators would connect directly to Xcel's distribution system, thereby freeing up some of Xcel's existing transmission capacity to meet future needs and permit Xcel to avoid costs to expand its system.[74] By Geronimo's calculation, this feature would save Xcel $3.24 million in transmission costs per year, or $33 million in present value of societal cost.[75] But the Department explains that, because the record demonstrated no need to expand Xcel's transmission system in the areas Geronimo proposed to interconnect, the Department declined to incorporate these alleged savings into its analysis.[76]

Some of the ALJ's concerns with the Department's analysis may reflect a misunderstanding of how the Department conducted its analysis. For example, in its first round of Strategist analysis the Department tested two demand forecasts – one included in Xcel's 2011 resource plan, the other reflecting Xcel's 2013 forecast which generated a lower estimate of need.[77] But the Department notes that neither analysis incorporated Xcel's new 7.3 percent planning reserve margin.[78] This larger margin would offset some of the anticipated reduction in Xcel's forecasted demand. Due to the magnitude, and frequency, of MISO's formula changes, the Department concludes that it is no longer clear how to calculate Xcel's reserve requirements.

Conclusion. In summary, the Department states that it continues to evaluate how MISO's changing methods may affect Minnesota's resource planning – including how it may influence the measurement of Xcel's demand-side management programs.[79] Given the uncertainty engendered by all the changed circumstances, the Department recommends that the Commission accept Xcel's offer to file status assessments in 2014 and 2015.[80] The Department supports Xcel's efforts to

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[72] ALJ's Report, Findings 205-206, citing Ex. 13 at 31 (Distributed Solar Energy Proposal); Ex. 46 at 35 (Wishart Direct); Ex. 61 at 7 (Beach Rebuttal).

[73] Ex. 81 at CJS-5 at 4 (Shaw Direct Attachments). Xcel would incur any costs associated with a proposal's transmission losses through the differential in locational marginal prices (LMP) between a generator and the retail customers receiving the electricity. Xcel analyzed the LMP differential for all bids except for the Geronimo proposal.

[74] ALJ's Report, Finding 207, citing Ex. 13 at 9-12 (Geronimo Proposal).

[75] *Id.*, Finding 208, 210, citing Ex. 13 at 9-12 (Geronimo Proposal); Ex. 59 at 20 (Engelking Rebuttal).

[76] Ex. 59 at 20 (Engelking Rebuttal); Ex. 61 at 9-10 (Beach Rebuttal). The Department also disputed Geronimo's calculation of benefits, noting that the benefits would decline over time as the solar panels' generating capacity deteriorated. *Id*.

[77] Ex. 83 at 22-25 (Rakow Direct).

[78] *Id*. at 39.

[79] *Id*. at 23 n.11.

[80] Ex. 85 at 7 (Rakow Rebuttal).

economize by negotiating with the project proposers for the discretion to postpone implementation of any selected project.[81] Finally, the Department recommends that the Commission require the selected bidders to bear the consequences of their statements, and to refrain from shifting more costs to ratepayers than were reflected in the Department's analysis of the project.[82]

B. Calpine

Calpine championed the use of the Levelized Cost of Electricity model for evaluating competing proposals – although Calpine restricted its analysis solely to the gas-powered proposals. Employing this model, Calpine argues that it has demonstrated that its Mankato proposal is the least-cost option among the gas-powered resources.

Nevertheless, Calpine also notes that the Strategist model also identified Calpine as a least-cost option under some circumstances, and as a competitive option under most circumstances.

As environmental regulations prompt the closure of ever more base load coal plants, Calpine argues that Xcel will need more than just the peaking capacity offered by Invenergy's and Xcel's proposals.

C. Environmental Intervenors

The Environmental Intervenors support Geronimo's proposal, citing many of the same arguments made by the ALJ.

First, the Environmental Intervenors argue that the Commission's order finding need for new resources should be reconsidered in light of current circumstances, that Xcel bears the burden of demonstrating need, and that the record shows that Xcel's needs through 2019 are modest at best. The Intervenors reject the idea that the Commission should ignore changes in demand or MISO's reserve requirements or Minnesota's Solar Energy Standard; indeed, statute directs the Commission to consider legal changes when evaluating a Certificate of Need docket.[83] And, according to the Environmental Intervenors, the Department's analysis of scenarios including demand levels at or below the level reflected in Xcel's Spring 2013 forecast is not a substitute for conducting a thorough analysis focused on the lower level of need forecast by Xcel.

Second, the Environmental Intervenors argue that statute directs the Commission to select a generator using renewable sources of energy unless the Commission finds that Xcel has proven that doing so would not be in the public interest. [84] The Intervenors then argue that the Commission should evaluate the public interest with due consideration for complying with the state's greenhouse gas reduction goals, the renewable energy standard, or the solar energy

[81] Ex. 86 at 11-12 (Rakow Rebuttal); *See,* Hearing Transcript, Vol. 2 at 55. The Department did not express an opinion on Xcel's desire to negotiate for the right to cancel implementation of a selected project.

[82] Ex. 82 at 4 -5 (Shaw Rebuttal).

[83] Minn. Stat. § 216B.243, subd. 3(2).

[84] Minn. Stat. § 216B.2422, subd. 4.

standard.[85] In addition, they cite the state's environmental policy, Minn. Stat. Chap. 116D, for the proposition that the state may not grant a permit for actions that would cause pollution if there are feasible and prudent alternatives – and an alternative cannot be dismissed as infeasible or imprudent merely because it costs more. Minn. Stat. § 116D.04, subd. 6, states:

> No state action significantly affecting the quality of the environment shall be allowed, nor shall any permit for natural resources management and development be granted, where such action or permit has caused or is likely to cause pollution, impairment, or destruction of the air, water, land or other natural resources located within the state, so long as there is a feasible and prudent alternative consistent with the reasonable requirements of the public health, safety, and welfare and the state's paramount concern for the protection of its air, water, land and other natural resources from pollution, impairment, or destruction. *Economic considerations alone shall not justify such conduct.* (Emphasis added.)

Third, the Environmental Intervenors argue that the Commission's analysis should acknowledge the particular value of Geronimo's proposal, including the federal tax credit for solar power and the value of the resulting S-RECs – whether those S-RECs are sold or used to help Xcel comply with the Solar Energy Standard. While the Department questions Geronimo's estimate of the value of an S-REC, the Environmental Intervenors note that no party offered a different estimate.

According to the Environmental Intervenors, Xcel's plan to solicit proposals for meeting its obligations under the Solar Energy Standard in no way diminishes the merits of Geronimo's proposal for purposes of the current docket, or justifies deferring consideration of the proposal until this later proceeding. And given the competitive nature of the current proceeding – in which Geronimo knew that its proposal would be competing with gas-powered generators – the Environmental Intervenors found no support for the suggestion that a future proceeding would generate cheaper sources of solar power.

D. Geronimo

Geronimo submitted two different pricing proposals for the parties' consideration; each proposal would have the effect of providing Xcel with all the renewable energy credits (RECs) or solar renewable energy credits arising from Geronimo's proposal.[86]

Geronimo supports the ALJ's analysis and recommendation, and shares many of the ALJ's criticisms of the analysis performed by other parties. In particular, Geronimo faults the Department's analysis for failing to give sufficient (or any) weight to the value of Geronimo's low-emissions, S-RECs, or transmission cost savings. Xcel could use the S-RECs to help meet its Solar Energy Standard mandate, Geronimo argues, or could sell them.[87]

In addition, Geronimo notes that both the Department and Xcel conducted their modeling while relying on imputed cost and performance data from generic generators. In the case of generic

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[85] *Id.*

[86] Ex. 13 at 1, 19 (Geronimo Proposal); Ex. 57 at 5 (Engelking Direct).

[87] Ex. 13 at 1 (Geronimo Proposal).

gas-powered generators, Xcel generated the relevant data based on its own experiences with such generators – and in fact, the cost of these generic generators proved to be higher than the cost of any of the gas-powered proposals. In contrast, Xcel has had little or no experience with solar-powered generators, and the costs Xcel imputed to a generic solar-powered generator proved to be cheaper than the cost of Geronimo's proposal. Geronimo argues that this modeling artifact skewed the results against its proposal.

E. GRE

GRE has submitted a proposal to sell Xcel MISO Zone 1 Resource Credits. GRE's proposal identified two different amounts of credits, with the precise quantity regarded as a trade secret.

Under GRE's proposal no new facilities would be constructed and no rights to energy production would be transferred to Xcel. If either of GRE's proposals is selected, GRE would maintain its current energy production rights and MISO would continue to dispatch GRE's existing generation resources. Xcel could use the credits to meet its reliability goals, but would need some other source of energy – its own generators, or purchases from a third party – to meet the needs of its customers.

GRE argues that its proposal has no adverse environmental consequences. If GRE's proposal is not selected, GRE would continue to operate its resource portfolio in the same way as it does today. GRE would likely offer to sell its capacity credits to others in the market, or through MISO's annual capacity auction. In other words, the environmental consequences will likely be the same whether or not Xcel buys GRE's credits.

GRE initially proposed to sell to Xcel credits for a period of three years, but later agreed to offer Xcel the option of buying credits for only two years. The Department declined to consider this second proposal in its Strategist modeling on the grounds that GRE had made the offer too late in the proceedings. The first round of the Department's analysis found that the flexibility provided by GRE's three-year proposal was not worth the cost, and the Department excluded further consideration of GRE's proposal from the second and third rounds of the Department's Strategist analysis. GRE argues that the Department's analysis needlessly precluded GRE's proposals from consideration.

F. Invenergy

Invenergy supports its Cannon Falls and Hampton combustion turbine proposals. Noting that Xcel's forecasted need for power had declined for various reasons, Invenergy argues that the most economic way to serve Xcel's remaining demand is through the use of peaking generators such as combustion turbines. Indeed, while Xcel's analysis favors gas-powered generators, Invenergy argues that this analysis understated the benefits of combustion turbines and overstated the benefits of intermediate generators such as Calpine's combined cycle plant.

Invenergy challenges the merits of Calpine's Levelized Cost of Electricity analysis of the various proposals, arguing that the analysis is skewed to favor intermediate generators over peaking generators. Invenergy argues that Xcel's forecast demonstrates a need for peaking generators, whereas Xcel already has excess intermediate capacity.

If the Commission elects to authorize construction of a combustion turbine, Invenergy favors its proposed turbine over Xcel's. Given Xcel's modest forecasts of demand, Invenergy argues that its 179 MW proposals would be a better fit for Xcel's modest demand forecasts than would be Xcel's 215 MW Black Dog Unit 6 proposal.

Finally, Invenergy argues that a power purchase agreement with a party such as itself would better shield ratepayers from bearing hidden costs than an arrangement with Xcel's own generator. But Invenergy argues that Xcel's analysis discriminates against power purchase proposals. In conducting an analysis comparing Invenergy's and Xcel's proposals, Xcel assumed that it would not need to replace its own generator throughout the 35-year period of its analysis – but assumed that it would need to build a substitute generator to replace the Invenergy generator at the end of Invenergy's proposed 20-year power purchase agreement. Invenergy argues that it would have made more sense to assume extending the term of the contract – an option Invenergy is willing to offer.

G. NDPSC Advocacy Staff

The NDPSC Advocacy Staff express concern about geographical equity. According to the NDPSC Advocacy Staff, Xcel serves four of North Dakota's five largest cities yet has built no adjacent generators. This places North Dakota cities at risk for power outages in the event of a transmission line failure, they argue. Consequently the NDPSC Advocacy Staff favors Xcel's proposal to build two gas-powered generators at Hankinson, North Dakota; they ask the Commission to place a premium on the reliability the Hankinson project would contribute to the local grid, even if the plant proved to be more expensive than some others.

But given the degree of uncertainty and changed circumstances in this docket, if the Commission declined to authorize the Hankinson proposals, the NDPSC Advocacy Staff would recommend deferring action until after Xcel's next resource plan.

H. Xcel

Xcel disputes the ALJ's Findings and his conclusion. In particular, while changed circumstances may justify reducing the amount of capacity to acquire in this docket, Xcel denies that they justify the forecast adopted by the ALJ.

In addition, Xcel joins the Department and Invenergy in favoring the reliance on the Strategist model rather than the Levelized Cost of Electricity model.

Xcel disagrees with the ALJ's preference for deferring necessary resource decisions. Xcel warns against delay. Xcel finds the current round of proposals attractive and the record well developed; it is unclear that future proceedings will provide proposals with such attractive terms.

Moreover, while Xcel did estimate that it could erect a combustion turbine in 21 months, Xcel suspects that the ALJ has mistaken an estimate for a planning criterion. To have a new generator ready by 2017, Xcel would propose to build Black Dog Unit 6 in 2016 and 2017. Under its proposal, decommissioning, demolition and removal of the existing Unit 4 turbine, generator, boiler and related equipment would need to begin in the fall of 2014.[88] Delaying the start of this

[88] Ex. 1 at 1-11 (Xcel Energy Proposal).

process could delay the end date.

Much like the Department, Xcel argues that Geronimo's claim to be able to avoid approximately $9 million in transmission losses is insignificant, given that the Strategist model indicated that Geronimo's proposal would exceed the cost of other proposals by $34 million (measured in terms of the present value of societal costs). Moreover, Xcel argues that Geronimo made it impossible to calculate this alleged savings because Geronimo could not state precisely the size and location of its proposed generators.[89]

Xcel disputes the Environmental Intervenor's claim that Minn. Stat. § 116D.04, subd. 6, bars the Commission from authorizing the construction of a generator that might cause "pollution, impairment, or destruction of … natural resources" whenever there is the option to authorize construction of a plant that does not emit pollution. According to Xcel, the statutory proscription arises only after a party shows that the state action would result in the violation of an environmental quality standard, limitation, rule, order, license, stipulation agreement, or permit, or would materially adversely affect the environment.[90]

Xcel takes exception to how the ALJ applied the Certificate of Need criteria to the record. In particular, Xcel argues that nothing in the record of this case demonstrates that any of the parties' proposals would fail to comply with the legal requirements of any jurisdiction.

Finally, Xcel addresses procedural matters. When the Commission selects the proposal or proposals that best fulfill Xcel's needs in this docket, Xcel recommends that the Commission direct Xcel and the winning bidders to negotiate terms anticipating the possibility of project delay and/or cancellation. Second, given changes in MISO's reserve requirement formula and other factors, Xcel states its willingness to provide reports in the fall of 2014 and 2015 regarding its assessment of its resource needs.[91]

I. Xcel Large Industrials

The Xcel Large Industrials largely share the view of the ALJ, but go further. They argue that the degree of changed circumstances in this docket render Xcel's demand forecast unreliable, and consequently ask the Commission to postpone any decisions until after Xcel's next resource plan.

If the Commission concludes that it must select one or more proposals, the Xcel Large Industrials would urge the Commission to proceed cautiously – that is, erring on the side of making fewer, and

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[89] Ex. 81 at CJS-5 at 4 (Shaw Direct Attachments). Xcel would incur any costs associated with a proposal's transmission losses through the differential in locational marginal prices (LMP) between a generator and the retail customers receiving the electricity. Xcel analyzed the LMP differential for all bids except for the Geronimo proposal.

[90] Xcel Reply Brief at n. 88; Xcel Exceptions at n.66, citing *Iron Rangers for Responsible Ridge Action v. Iron Range Resources*, 531 N.W.2d 874, 882 (Minn. Ct. App. 1995) *rev. denied* (Minn. July 28, 1995), and *In re Application for Air Emission Facility Permit*, 566 N.W.2d 98, 105 (Minn. Ct. App. 1997) (no finding of material adverse environmental effects where a facility will comply with all applicable state and federal permitting standards).

[91] Ex. 46 at 11 (Wishard Direct); Ex. 48 at 27 (Wishart Rebuttal).

later, capital investments. Because the Solar Energy Standard requires Xcel to acquire more solar power in any event, the Xcel Large Industrials recommend that the Commission make Geronimo's proposal their first choice. Beyond this, the Xcel Large Industrials would favor purchasing GRE's offer of MISO capacity credits over a two- or three-year period, thereby delaying the need to make a longer-term capital investment until after Xcel's next resource plan. But the Xcel Large Industrials recommend making any decision contingent upon decisions rendered in Xcel's next resource plan.

VII. Commission Action

A. Environmental Report

The Commission finds that the Department's environmental report addresses the issues raised in the Department's scoping decision, including the consequences identified in Minn. R. 7849.1500, subpart 2 (air emissions, visibility impacts, ozone, fuel availability and fuel transportation, electric transmission facilities associated with each proposal, water appropriations, amount and types of wastewater discharges, solid and hazardous wastes, anticipated noise). Consequently the Commission finds that the environmental report, supported by the record of this proceeding, addresses the issues outlined in the Department's Scoping Decision.

B. Changed Circumstances and the Resource Plan Order

Citing circumstances that have changed since the Commission approved Xcel's last resource plan, the ALJ sought to reevaluate the amount of capacity that Xcel should seek to acquire via the current proceedings. Other parties argued that efforts to reevaluate this need exceeded the scope of the current proceedings, and argued for evaluating the proposals based on the level of need established in the resource plan.

The Commission did not specify the precise amount of capacity to be obtained via the current docket. Rather, the Commission stated in its March 5, 2013 Order:

> [P]arties disagree about the magnitude of Xcel's needs. For example, the Environmental Intervenors and the [Xcel Large Industrials] 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 has 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.[92]

Moreover, the Commission concluded that this description sufficed "to inform potential bidders of the *scope* of projects that the Commission will be considering."[93] The description has fulfilled this role, attracting proposals of appropriate size.

Nothing in the order indicated that the Commission would refrain from considering all relevant factors in determining the amount of capacity to select via this competitive resource acquisition process. Consequently the Commission will evaluate the bidders' proposals to determine which would best meet the needs identified in this record and the Commission's March 5, 2013 Order.

C. Changed Circumstances Generally

1. Introduction

The Commission's March 2013 resource plan order found that Xcel had demonstrated the need for at least 150 MW by 2017, potentially increasing to 500 MW by 2019.[94] Since then, a variety of circumstances have changed pertaining to energy resources on Xcel's system and potential changes in need estimated by Xcel.[95] Because uncertainty makes errors more likely, the ALJ opted to err on the side of making fewer and smaller commitments, rather than more and larger ones.[96]

The Commission agrees with the ALJ that uncertainty in the record is an important fact to weigh in making a commitment of resources. But the Commission concludes that the strategy recommended in the ALJ's Report gives insufficient attention to uncertainty – specifically, the uncertainty in the data suggesting that Xcel will need no more than 26 MW by 2019. Instead, the Commission will err on the side of ensuring that Xcel has enough capacity to meet the needs of its customers. The future will always be uncertain, but the Commission must proceed to make the necessary choices on the basis of a rigorous analysis of the data that *is* in the record.[97]

Among the arguments that Xcel should curtail the amount of capacity it acquires in this docket,

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[92] *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, Docket No. E-002/RP-10-825, Order Approving Plan, Finding Need, Establishing Filing Requirements, and Closing Docket (March 5, 2013) at 2 and 6 (emphasis in original).

[93] *Id.* (emphasis added).

[94] See *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, Docket No. E-002/RP-10-825, Order Approving Plan, Finding Need, Establishing Filing Requirements, and Closing Docket (March 5, 2013).

[95] ALJ's Report, Finding 12.

[96] *Id.*, citing Ex. 49 at 2 (Alder's Direct).

[97] Ex. 49 at 7 (Alders Direct) ("[T]here are factors that create uncertainty and could materially affect our resource need assessment. The new need assessment is another data point that should be considered in analyzing which resource proposals should be selected to address the range of [Xcel]'s potential need in the 2017-2019 timeframe.").

parties cite the following:

- The Legislature adopted the Solar Energy Standard, effectively requiring Xcel to acquire between 72 and 200 MW of accredited capacity from solar-powered generators by 2020.

- Xcel entered into arrangements with the operators of wind turbines having a combined nameplate capacity of 750 MW – that is, 550 MW more than contemplated in Xcel's resource plan.

- Xcel's Spring 2013 forecast predicted lower growth than anticipated in Xcel's resource plan.

- MISO changed the formula for calculating short-term reserve margins.[98]

- Xcel rates the capacity of its demand-side management programs based on how well they perform during Xcel's peak – not during MISO's peak.

- Xcel revised its estimates of the generating capacity of its existing generators.

All these factors were analyzed in this proceeding. The Commission finds that some of these changes may appropriately reduce the amount of capacity to be acquired in this proceeding, but other changes will have no effect, or ambiguous effects, on Xcel's capacity needs.

2. Solar Energy Standard

Because the Legislature has directed Xcel to acquire more energy from solar power, Xcel will have less need for power from other sources – potentially including from resources acquired through the current docket. Consequently, the Commission concurs with the parties arguing that this new development justifies reducing the amount of capacity Xcel would acquire through this proceeding. That said, quantifying how much this mandate should reduce Xcel's acquisitions is complicated by the fact that Geronimo's proposal could be used to fulfill part of the Solar Energy Standard mandate, or could be sold. Conceptually, Xcel's demand for Geronimo's proposal is 72 MW larger than its demand for the other proposals.

3. 750 MW Wind "Power" Acquisition

Xcel has purchased and contracted for wind turbines having a total nominal capacity of 750 MW – but as a source of *energy*, not *capacity*. That is, the turbines are intended to permit Xcel to reduce the amount of fuel it burns at its other generators during periods of low and moderate demand. But the turbines are unlikely to help Xcel meet demand on peak days because, on peak days, the transmission grid will have no spare capacity to permit Xcel to receive this power. These transmission constraints are expected to continue until 2021 at the earliest; consequently these new wind resources have no bearing on Xcel's capacity needs in the 2017 – 2019 timeframe.

[98] Ex. 46 at 37 (Wishart Direct). See generally *In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of 600 MW of Wind Generation*, Docket No. E-002/M-13-603; *In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of 150 MW of Wind Generation*, Docket No. E-002/M-13-716.

4. New Demand Forecast

Xcel regularly revises its forecasts of customer demand within its service area. And the demand levels indicated by Xcel's Spring 2013 forecast were less than the levels reflected in Xcel's last resource plan.

However, the Department notes that Xcel's resource plan forecast, unlike Xcel's Spring 2013 forecast, received the benefit of Department review and Commission approval. Consequently the Department did not rely on Xcel's revised forecast for purposes of analyzing the parties' proposals.[99]

That said, the Department analyzed the parties' proposals under a variety of circumstances -- including circumstances that would reflect levels of demand indicated by Xcel's spring 2013 sales forecast.[100] On this basis the Commission concludes that the record adequately incorporates and reflects the contingency that demand in Xcel's service area has declined since the time of Xcel's last resource plan.

5. MISO's Reserve Requirement Formula

It is unclear how changes in MISO's new reserve requirement formula should influence the amount of power Xcel will acquire via this docket. As previously discussed, the new formula is calculated on the basis of the planning reserve margin multiplied by the level of demand on Xcel's system during the hour of MISO's peak demand.

The time of Xcel's system peak differs from the MISO system peak; between 2006 and 2012, demand on Xcel's system was on average 5 percent lower during MISO's peak than during Xcel's peak.[101] Consequently the ALJ observed that this aspect of MISO's new formula should tend to reduce the amount of capacity Xcel is required to maintain. However, this capacity "savings" has proven unreliable, varying from zero percent (in 2006) to 14 percent (in 2007).[102]

Moreover, this change in MISO's reserve margin formula was implemented at the same time as a countervailing change in the formula: the size of the planning reserve margin. MISO increased this margin from 3.79 percent to 6.2 percent. MISO acknowledges that utilities need stable standards upon which to base their plans – while also acknowledging that MISO was again changing the planning reserve margin to 7.3 percent.[103]

The forecasted amount of Xcel's need varies substantially depending upon which reserve requirement formula is used. MISO's new method of calculating reserves effectively reduces Xcel's peak demand by 275 MW to 290 MW, even without adjusting for changes in the calculation

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99 Hearing Transcript - Vol. 2 at 29-30.

100 Ex. 76 at 13 (Shah Direct).

101 ALJ's Report, Finding 21.

102 Ex. 46 at 8-9 and Table 3 (Wishart Direct); Ex. 83 at 23-24 (Rakow Direct).

103 Ex. 46 at 7-11 (Wishart Direct).

of Xcel's demand-side management capability or changes in MISO's short-term planning reserve margin.[104]

Clearly Xcel must, at a minimum, plan to have sufficient capacity to meet its reserve requirements. But given the level of uncertainty created by the new formula, it is far from clear that Xcel's new reserve requirement, even if lower than Xcel's previous reserve requirement, should serve as a guide for purposes of Xcel's longer-range plan.

6. Demand-Side Management

Xcel has historically measured its demand-side management programs on their ability to help Xcel shed load during times of *Xcel's* peak demand; Xcel has not calibrated the performance of these programs during *MISO's* peak demand. For example, subscribers to Xcel's Saver's Switch program authorize Xcel to cycle their air conditioners on and off. While this program helps Xcel reduce the demand that air conditioners place on Xcel's system at any one time, estimates of the amount of demand savings this program can produce during MISO's peak period vary by more than 100 MW.[105] Any decrease in the rated capacity of Xcel's demand-side management programs must be offset by an increase in Xcel's reserve requirement.

In short, MISO's new reserve margin formula adds an additional level of uncertainty regarding the performance of demand-side programs.

7. Capacity of Existing Generators

Each generator has a rated nameplate capacity, identifying the maximum power the generator can produce without shortening its operational life. Typically a generator's capacity will decline over time, and due to circumstances such as hot, humid weather. The rated capacities of Xcel's generators have recently been revised, contributing one more degree of uncertainty about the relationship of power supply and demand.

8. Effect of Changed Circumstances

The ALJ cites Xcel witness Wishart for the proposition that MISO's new reserve margin formula reduced Xcel's reserve requirements by approximately 200 MW, and that various changes can be combined to produce a forecast purporting to show that Xcel will not need additional capacity until 2019, when Xcel will need to add a mere 26 MW.[106] But Wishart made this forecast based on Xcel's untested 2013 demand forecast, MISO's 2013 reserve requirement formula – a formula MISO has already stated that it plans to increase – and on the untested assumption that Xcel's demand-side resource capacity will remain unchanged even as applied to MISO's peak demand rather than Xcel's peak.

Overall, these changes might reduce Xcel's expected capacity needs in general – but they also introduce greater uncertainty into the analysis. Utilities cannot know which reserve margin

[104] *Id.*

[105] *Id.* at 24-25.

[106] ALJ's Report, Findings 24 - 25, citing Ex. 46 at 2, 10 (Wishart Direct).

formula MISO will use in the long run; Xcel has less confidence in the performance of its demand-side management programs during MISO's peak than during its own.[107]

Taking into account the consequence of Xcel's new demand forecast, the new Solar Energy Standard, and changes in the forecasted capacity of Xcel's existing generators and demand-side management programs, Xcel reduced its anticipated need for new capacity to 93 MW in 2017, potentially growing to 307 MW by 2019.[108] This represents a substantial decline from the Commission-approved level of demand. Nevertheless it remains within the range of demand analyzed by the Department.[109]

The Commission finds that the Strategist modeling performed by the Department and Xcel, using a wide range of assumptions, inputs, and considerations, provides sufficient information to form the foundation of the Commission's choices in this docket.

D. Certificate of Need Criteria

Parties dispute the manner in which the ALJ interpreted the criteria of Minn. R. 7849.0120 to evaluate the various proposals. The Commission both concurs in, and dissents from, the ALJ's findings.

1. Effect on Electric Supply's Future Adequacy, Reliability, or Efficiency

Minn. R. 7849.0120.A. addresses how the choice of resource might affect the future adequacy, reliability, or efficiency of energy supplied to the utility, its customers, and the people of Minnesota and neighboring states.

This docket was initially driven by the Commission's March 2013 order finding that Xcel had demonstrated the need for at least 150 MW by 2017, potentially increasing to 500 MW by 2019.[110] But given a broad range of changed circumstances, the ALJ concluded that Xcel would not need to acquire any new capacity for 2017 or 2018, and would need only 26 MW by 2019. And the ALJ found that it would not be efficient to procure large generators, such as gas turbines, to meet this modest need.[111]

As previously discussed, the Commission concurs with the view that changed circumstances may justify Xcel reducing or delaying its acquisition of new capacity. But the Commission rejects the view that changed circumstances justify reducing Xcel's acquisitions to no more than 26 MW by 2019. The analysis that led to this conclusion reflected the combined effects of all dynamics that might reduce an estimate of need – while omitting consideration of the corresponding dynamics

[107] Ex. 46 at 9 (Wishart Direct) and Ex. 83 at 24-25, 39 (Rakow Direct).

[108] Ex. 46 at 7-8 and Table 2 (Wishart Direct).

[109] Ex. 76 at 13 (Shah Direct).

[110] See *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, Docket No. E-002/RP-10-825, Order Approving Plan, Finding Need, Establishing Filing Requirements, and Closing Docket (March 5, 2013).

[111] ALJ's Report, Finding 250.

that might reasonably offset those reductions.

The future adequacy, reliability, and efficiency of power available to Xcel, its customers, and the people of Minnesota and neighboring states, depend upon a prudent assessment of need. Even Xcel's revised 2013 forecast, with further adjustments for the Solar Energy Standard and revised capacity ratings for Xcel's generators and demand-side management programs, demonstrates a need for more than 300 MW by 2019.

Thus, the Commission concurs with the ALJ that the record demonstrates sufficient demand to justify selecting the Geronimo proposal. But contrary to the ALJ's finding, this level of demand is also more than sufficient to justify selecting a new combustion turbine or combined cycle generator.

2. Reasonableness and Prudence

Minn. R. 7849.0120.B. addresses whether the record demonstrates by a preponderance of the evidence that some other facility is more reasonable and prudent. Addressing this question requires consideration of both process and substance.

Procedurally, the Commission must evaluate the tools the parties offer to help the Commission gauge reasonableness and prudence. The ALJ concludes, and Calpine and Geronimo agree, that a Levelized Cost of Electricity analysis provides better guidance than the Strategist capacity expansion model, and that the manner in which the Department and Xcel conducted their analysis led to biased results.

The Department, Invenergy, and Xcel argue the contrary, supporting both the Strategist model in general and their implementation of it. And under the current circumstances, the Commission agrees.

As previously discussed, a Levelized Cost of Electricity analysis calculates the net present value of the expected annual costs – including variable and fixed operations and maintenance costs, capital costs and the return on investment – divided by annual generation over the term of the proposal. However, it does not consider how a new resource would affect the utility's existing resources – for example, by helping to avoid additional capacity costs and variable costs, including fuel.

Because this model takes little or no account of the context within which a resource would be used, the analysis may be appropriate where competing resources will be used in identical contexts, and thus all other factors can be regarded as equal. But the U.S. Energy Information Administration concludes that "the direct comparison of the levelized cost of electricity across technologies is often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives."[112]

In the current docket, the Commission confronts a choice among vastly dissimilar proposals – proposals for peaking and intermediate capacity, for dispatchable and non-dispatchable generation, for solar-powered and gas-powered generators, for proposals that would be governed by a power purchase agreement and proposals that would be owned by Xcel outright, and between

[112] Ex. 47 at 16 (Wishart Rebuttal).

generators and transmission capacity credits.[113] This range of variables simply exceeds what a Levelized Cost of Electricity analysis is designed to consider.

In addition, the Strategist model permits the parties to compare the amount of pollution each proposal would generate, and to weigh this pollution on the basis of Commission-approved externality and regulatory values; a levelized analysis does not. In this circumstance, the evidence and long-standing Commission practice support the conclusion that capacity expansion modeling provides better predictions of costs and ratepayer effects than does a Levelized Cost of Electricity analysis.[114]

More substantively, the ALJ, Geronimo, and Calpine object to the manner in which the Department and Xcel conducted their Strategist modeling, and the conclusions they drew from it. The ALJ concluded a reasonable and prudent purchaser could not select any of the gas-powered proposals when Geronimo's proposal is the lowest-cost stand-alone resource when judged on the basis of the amount of energy it is expected to generate.[115] And the ALJ rejected the analyses of other parties on the theory that they had placed undue reliance on the demand forecast from Xcel's resource plan.

The record supports the conclusion that, on a stand-alone basis, Geronimo's proposal has the lowest ratio of cost to anticipated energy generated. But the record also shows that when analyzed as part of a system, Geronimo's proposal incurs the highest costs.[116] And, while parties disagree about the relative merits of relying on the forecast from Xcel's resource plan or Xcel's 2013 update, the Department analyzed all the proposals under a variety of scenarios – including levels of demand that were less than Xcel's 2013 forecast. Consequently, the Department's analysis cannot be dismissed on this basis. When combined, Xcel and the Department used a wide range of assumptions, inputs, and considerations in each of the Strategist models and the results provide a reasonable range of uncertainties, futures, and reasonable outputs to consider.

In sum, while the record clearly demonstrates the merits of Geronimo's proposal, the Commission rejects the ALJ's finding that reason and prudence precludes the selection of the gas-powered proposals as well.

3. Benefits Compatible with Nature, Society, and Health

Minn. R. 7849.0120.C. asks whether the proposed resource will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health.

The ALJ found that this criterion favors Geronimo's proposal, noting both its environmental benefits and its propensity to generate economic activity. Here, the Commission concurs. While

[113] Ex. 74 at 5–6 (Norman Rebuttal); Ex. 47 at 15–16 (Wishart Rebuttal); Department Reply Brief at 35.

[114] Ex. 47 at 2-3 (Wishart Rebuttal). Consequently the Commission declined to adopt findings or conclusions from the ALJ's Report grounded in the quantification of costs and benefits derived from the Levelized Cost of Electricity analysis, including Finding 255.

[115] ALJ's Report, Finding 257, citing Ex. 74 at 7 (Norman Rebuttal).

[116] *See,* Ex. 74 at 7 (Norman Rebuttal), referencing Dr. Rakow and Mr. Wishart's direct testimonies.

other parties argue that the cost of Geronimo's proposal outweighs its natural and socioeconomic advantages, no party has challenged the merits of Geronimo's proposal in terms of protecting the natural environment or human health.

The record shows that construction and operation of Geronimo's proposal, unlike the gas-powered proposals, would avoid generating a variety of pollutants. Relying on Geronimo's generators, each year Xcel could expect to avoid emitting 94,133 tons of carbon dioxide (CO_2), 115.98 tons of carbon monoxide (CO), 63.26 tons of nitrogen dioxides (NO_x), 27.08 tons of particulate matter (PM_{10}), 10.48 tons of sulfur dioxide (SO_2), 3.44 tons of volatile organic compounds (VOCs), and unspecified amounts of lead (Pb) and hazardous air pollutants (HAPs).[117] In addition, Geronimo's generators do not require water to generate power, thereby avoiding the need to tax aquifers or to discharge heated, chemical-laden wastewater into the environment.

The record also indicates that construction and operation of Geronimo's proposal would promote more employment, and more dispersed employment, than would the other projects. Geronimo's construction phase would generate approximately 500 jobs, dispersed in work crews of between 13 and 40 members each, plus generate roughly 10 permanent operations and maintenance positions.[118] In contrast, construction of Xcel's Black Dog Unit 6 proposal is not anticipated to require more than 60 workers at any one time. Calpine anticipates that approximately 250 construction workers would be employed during the peak of its construction activity. Invenergy estimates needing approximately 100 construction workers during the peak of construction activity.[119] Finally, no new operations jobs are expected to be created with the Black Dog, Calpine, or Invenergy proposals.[120]

4. Compliance with Laws of Other Jurisdictions

Minn. R. 7849.0120.D. asks whether a proposed facility "will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments."

Noting that the regulation of emissions has grown more restrictive, and may grow more restrictive yet, the ALJ reasoned that Geronimo poses the fewest risks of violating laws and policies beyond the Commission's jurisdiction because Geronimo's proposal produces the fewest emissions.[121]

Whatever the merits of the ALJ's conclusion in general, this fourth criterion merely asks whether the record proves that any given facility will fail to comply with laws and policies outside the Commission's jurisdiction. As the Department, Invenergy, and Xcel note, the record does not demonstrate that any of the proposed projects would fail this test. Consequently the Commission concludes that this fourth Certificate of Need criterion provides no advantage to any of the proposed projects.

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[117] Ex. 13 at 24, 34 (Distributed Solar Energy Proposal); Ex. 38 at 38 (Environmental Report).

[118] Ex. 38 at 31-33 (Environmental Report).

[119] *Id*. at 30-31 (Environmental Report).

[120] *Id.* at 29.

[121] ALJ's Report, Findings 282–289.

E. Conclusion

1. Geronimo's Proposal

In sum, the ALJ's Report demonstrates the merits of Geronimo's proposal, both for supporting the reliability and adequacy of Xcel's power supply, but also for promoting beneficial environmental and socioeconomic outcomes. In particular, the Commission notes the state policy favoring energy from renewable sources,[122]and the goal of reducing greenhouse gases relative to 2005 levels by 30 percent by 2025 and 80 percent by 2050.[123] Geronimo's proposal best advances these policies.

The principal objection to Geronimo's proposal has been cost. But whether an analysis shows Geronimo's proposal to be more expensive than the other proposals, or less expensive, or similar in cost, depends on the value given to solar energy, S-RECs, externality values, and other factors. While the Department's analysis found other proposals to be more cost-effective, the difference in the cost of Geronimo's proposal and other proposals was less than half a percent.[124]

Weighing all factors explored in this record, the Commission affirms the ALJ's recommendation and will select Geronimo's proposal.

2. GRE's Proposal

However, while the Commission is persuaded of the need to plan for more than 72 MW of accredited capacity, it will decline the ALJ's recommendation to also select GRE's proposal. Given the ALJ's conclusions about the limited demand growth in Xcel's service area, the ALJ's recommendation was driven by the flexibility and scalability offered by GRE.

The unique nature of GRE's proposal gives it this unusual degree of flexibility. GRE offers to sell capacity credits for two or three years. As such, GRE does not offer to add any new capacity or energy to the MISO system, or any longer-term solution to fill Xcel's need. And while GRE's proposal generates no environmental costs, it also generates no environmental benefits. That is, unlike Geronimo's proposal, GRE's proposal would not provide any substitute means for Xcel to acquire energy in a manner that imposes fewer costs on the environment.

Ultimately the Commission remains convinced that Xcel must plan for the possibility of demand levels consistent with the findings in its last resource plan. Both Xcel and the Department included some version of GRE's proposal in their Strategist modeling to determine if this capacity credit offer had sufficient value -- for example, by delaying the need to actually add resources to the system -- to warrant consideration. Their analyses showed that the costs of GRE's proposal

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[122] Minn. Stat. 216B.2422, subd. 4.

[123] Minn. Stat. 216H.02.

[124] Ex. 84 SRR-4A (Rakow Direct Attachments) (no package including Geronimo's proposal increases Xcel's present value of societal cost by more than 0.47 percent); Environmental Intervenors' Brief at 7–8 (adding Geronimo's proposal to the package of Cannon Falls and Black Dog Unit 6 increases the annual societal cost by 0.08 percent); Public Hearing Transcript, Vol. 1 at 145-46 (testimony of Geronimo witness Engelking) (cost differences between packages are "in the hundredths of a percent" of Xcel's system costs).

exceeded the value of delaying investment in a long-term solution.[125]

In an environment in which Xcel's need for new capacity is speculative and remote, GRE's proposal may have been an appropriate strategic choice. In an environment in which Xcel has demonstrated need for substantial capacity in the near term, GRE's short-term proposal serves no purpose. Based on this record, the Commission concludes that it is neither reasonable nor prudent for Xcel to pursue a capacity credit purchase from GRE to meet Xcel's level of need.

3. Gas-powered Proposals

Among the remaining options, the record demonstrates that Calpine's proposal, Invenergy's proposal, and Xcel's Black Dog Unit 6 proposal have comparable merits. Indeed, the deciding factor as between these proposals may rest in the specific terms of their agreements.

4. Draft Power Agreements

Consequently the Commission will direct Xcel to negotiate agreement terms with Calpine, Geronimo, and Invenergy for securing power from their proposals, and to draft equivalent terms under which Xcel would recover from ratepayers the cost of its Black Dog Unit 6 proposal. In accordance with Xcel's competitive resource acquisition process, Xcel will have four months in which to develop these terms and submit them for Commission approval – or, alternatively, to explain why it had not been able to develop these terms, and to propose how to proceed.

These terms should acknowledge that, for purposes of cost recovery, each bidder will be held to the prices and terms used to evaluate its bid. The terms should not put ratepayers at risk for costs that are higher than bid, or for promised levels of accredited capacity, energy, or other benefits that do not fully materialize. The Commission is not likely to regard as reasonable any terms that shift risk or unknown costs to ratepayers. If a bidder's actual costs prove to be lower than bid, however, the bidders should retain those savings.

In particular, the Commission notes that proposals offering flexible installation dates would provide opportunities for substantial savings to Xcel and its ratepayers. Consequently, while the parties are not required to incorporate such terms into their proposals, the Commission concurs with the ALJ, the Department, and Xcel that it would be appropriate for the Commission and the Department, in reviewing draft terms, to look for terms governing the possibility that a project might be delayed or cancelled.

5. Housekeeping Matters

In support of these decisions, the Commission adopts the ALJ's Report to the extent it is consistent with this order. The decisions set forth here are compatible with socioeconomic and environmental requirements, and compliant with other applicable state law.

To facilitate Commission oversight of the rest of this resource acquisition process, the Commission will accept Xcel's offer to file status reports regarding changes in Xcel's resource needs, including needs resulting from changes in MISO's reserve requirements. The Commission

[125] Ex. 46 at 24 (Wishart Direct).

will direct Xcel to file its first report by October 2014, and the second report a year later.

Finally, the Commission observes that Xcel's next resource plan is due July 1, 2014. However, the current docket has amply documented a list of changed circumstances that would complicate Xcel's resource planning. Xcel may add to that list the unresolved state of the current docket. In light of these developments, the Commission finds it appropriate to extend the date of Xcel's next resource plan to January 2, 2015.

ORDER

1. Northern States Power Company d/b/a Xcel Energy shall negotiate terms for acquiring new supply resources with the following parties:

   A. Xcel shall negotiate a draft power purchase agreement with Geronimo Wind Energy, LLC, d/b/a Geronimo Energy, LLC, and submit the agreement for Commission review to ensure that the negotiated terms are consistent with the public interest.

   B. Xcel shall negotiate draft power purchase agreements with Calpine Corporation and Invenergy Thermal Development, LLC, and shall develop price terms for Black Dog Unit 6. Xcel shall then submit the agreements and terms for Commission review to determine which of these project(s), if any, best addresses Xcel's overall system needs identified in this record and in the Commission's Order Approving Plan, Finding Need, Establishing Filing Requirements, and Closing Docket (March 5, 2013) issued in Docket No. E-002/RP-10-825, *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*.

   Within four months, Xcel shall file these terms for Commission approval, or shall explain its failure to do so and recommend how to proceed.

2. Regarding these terms:

   A. Calpine, Geronimo, Invenergy, and Xcel shall be held to the prices and terms used to evaluate each bid for the purpose of cost recovery from Xcel ratepayers. Ratepayers must not be put at risk for costs that are higher than bid or for benefits assumed in bids that do not materialize. If actual costs are lower than bid, the bidders should be allowed to keep those savings.

   B. The agreements must provide terms that sufficiently protect ratepayers from risks associated with the non-deliverability of accredited capacity and/or energy from the project(s) as proposed.

   C. The Commission is unlikely to find it reasonable for Xcel to enter into an agreement in which negotiated terms shift risk or unknown costs to ratepayers.

D. Delay and cancellation provisions are appropriate considerations for power purchase agreement negotiations.

3. The Commission adopts the ALJ's Findings of Fact, Conclusions of Law, and Recommendation (December 31, 2013) to the extent that it is consistent with this order.

4. Xcel shall file status updates in October 2014 and October 2015 on any changes in Xcel's resource needs, including needs resulting from changes in MISO's reserve requirements.

5. The Commission extends the deadline for Xcel's next resource plan to January 2, 2015.

6. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

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CERTIFICATE OF SERVICE

I, Robin Rice, hereby certify that I have this day, served a true and correct copy of the following document to all persons at the addresses indicated below or on the attached list by electronic filing, electronic mail, courier, interoffice mail or by depositing the same enveloped with postage paid in the United States mail at St. Paul, Minnesota.

Minnesota Public Utilities Commission

ORDER DIRECTING XCEL TO NEGOTIATE DRAFT AGREEMENTS WITH SELECTED PARTIES

Docket Number E-002/CN-1240

Dated this 23rd day of May,2014

/s/ Robin Rice

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John A. Tuma	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need	ISSUE DATE: February 5, 2015 DOCKET NO. E-002/CN-12-1240
In the Matter of a Draft Purchase Power Agreement with Geronimo Wind Energy, LLC, d/b/a Geronimo Energy, LLC	DOCKET NO. E-002/M-14-788 DOCKET NO. E-002/M-14-789
In the Matter of Draft Purchase Power Agreements with Calpine Corporation and Invenergy Thermal Development, and Proposed Price Terms for Black Dog Unit 6	ORDER APPROVING POWER PURCHASE AGREEMENT WITH CALPINE, APPROVING POWER PURCHASE AGREEMENT WITH GERONIMO, AND APPROVING PRICE TERMS WITH XCEL

PROCEDURAL HISTORY

I. History Leading to Commission Order

On November 21, 2012, the Commission initiated Docket No. E-002/CN-12-1240, *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need*, Docket No. E-002/CN-12-1240 (*12-1240 Docket*). In it, the Commission directed Northern States Power Company d/b/a Xcel Energy (Xcel) to solicit proposals from project developers to provide the additional resources needed to serve Xcel's customers.[1] The Commission later found that Xcel had demonstrated the need for an additional capacity of 150 megawatts (MW) by 2017, increasing up to 500 MW by 2019.[2] These findings provided the context in which project developers submitted their proposals.

[1] *12-1240 Docket*, Order Closing Docket, Establishing New Docket, and Schedule for Competitive Resource Acquisition Process (November 21, 2012).

[2] See *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, Docket No. E-002/RP-10-825, Order Approving Plan, Finding Need, Establishing Filing Requirements, and Closing Docket (March 5, 2013).

On December 31, 2013, an administrative law judge (ALJ), after conducting evidentiary hearings in the *12-1240 Docket*, issued his Findings of Fact, Conclusions of Law, and Recommendation.[3] The ALJ concluded that changes in Xcel's need forecast justified a strategy of minimizing capital commitments. In this context the ALJ concluded that the solar-powered generators proposed by Geronimo Wind Energy, LLC, d/b/a Geronimo Energy, LLC (Geronimo) provided the optimal combination of low cost and high flexibility. To the extent the Commission found it appropriate to acquire additional capacity, the ALJ recommended buying a utility's *capacity credits* – that is, the right to transmit electricity across the transmission grid for two or three years.

II. May 2014 Order

After lengthy proceedings, on May 23, 2014, the Commission issued its Order Directing Xcel to Negotiate Draft Agreements with Selected Parties (May 2014 Order). In that order the Commission found that Xcel continued to need new sources of generation to meet its customers' needs. The Commission found that the cost of the temporary capacity credits was greater than the cost of simply accelerating the implementation of some more permanent solution. And the Commission found that the record justified ordering Xcel to pursue negotiating finalized terms for four rival proposals:

- Geronimo's collection of solar-powered generators to be installed at various locations throughout Minnesota, with an accredited capacity of 72 megawatts (MW).

- Calpine Corporation's Mankato Energy Center II, a 345 MW gas-powered generator to be installed in Mankato.

- Invenergy Thermal Development, LLC, (Invenergy)'s Cannon Falls II, 178.5 MW gas-powered generator to be installed in Cannon Falls.

- Xcel's Black Dog Unit 6, a 215 MW gas-powered generator to be installed in Burnsville.

Specifically, the Commission selected Geronimo's proposal for implementation, provided the parties could negotiate a power purchase agreement that was consistent with the public interest. The Commission also stated that it would review the finalized agreements for Calpine's and Invenergy's proposals, and price terms for Xcel's proposal, to determine which, if any, would best address Xcel's remaining system needs.

III. Subsequent Events

Calpine, Geronimo, and Invenergy each formed subsidiaries -- respectively, Mankato Energy Center II, LLC; Aurora Distributed Solar, LLC; and Invenergy Cannon Falls II, LLC -- for the purpose of owning and operating their proposed projects. For ease of exposition, in this order these entities will also be referred to as Calpine, Geronimo, and Invenergy, respectively.

On September 23, 2014, Xcel made the compliance filing required by the May 2014 Order; Xcel revised the filing on October 2. The filing contained the following:

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[3] *12-1240 Docket*, Findings of Fact, Conclusions of Law, and Recommendation (December 31, 2013).

- A draft power purchase agreement (PPA) that Xcel had negotiated with Geronimo for generators to begin operations by 2016.

- Draft agreements that Xcel had negotiated with Calpine and Invenergy, and a statement reaffirming terms Xcel had previously proposed for Black Dog Unit 6, for generators to begin operations by 2018 or 2019.

- Xcel's updated assessment of need, now predicting that Xcel would not require additional resources until 2024.

Citing its revised need assessment, Xcel's recommended that the Commission refrain from selecting any gas-powered generators at this time, and instead authorize Xcel to re-negotiate the agreements to establish terms for a later implementation date. And Xcel recommended, in effect, that the Commission refer consideration of Geronimo's proposal to a separate docket for solar-powered generators, discussed below.

On September 25, 2014, the Commission initiated two dockets -- Docket No. E-002/M-14-788, *In the Matter of a Draft Purchase Power Agreement with Geronimo Wind Energy, LLC, d/b/a Geronimo Energy, LLC,* and Docket No. E-002/M-14-789, *In the Matter of Draft Purchase Power Agreements with Calpine Corporation and Invenergy Thermal Development and Proposed Price Terms for Black Dog Unit 6* -- soliciting comments on Xcel's compliance filing.

By November 3, 2014, the Commission had received comments, reply comments, or both, from –

- the project developers,
- the Minnesota Department of Commerce (the Department), and
- the Minnesota Center for Environmental Advocacy (MCEA), appearing on behalf of MCEA, Fresh Energy, Sierra Club, and Izaak Walton League - Midwest Office (collectively, the Environmental Intervenors).

On December 8, 2014, the Commission met to receive oral arguments from the parties.

On December 12, 2014, Xcel filed proposed revisions to Geronimo's power purchase agreement that were agreeable to both Xcel and Geronimo, in response to the Commission's concerns about the agreement's language governing cost recovery. In addition, Geronimo and Xcel filed joint comments addressing these concerns.

On December 15, 2014, the Commission met to consider the matter, and again received comments from the parties.

FINDINGS AND CONCLUSIONS

I. Summary

In this order the Commission reviews Xcel's compliance filing, and the parties' comments on it. The Commission then reviews salient terms for the projects offered by the various developers. Finally, in rendering a decision on the merits, the Commission does the following:

- Finds that the terms offered by each of the project developers are consistent with the public interest and consistent with the prices and terms used to evaluate their proposals in this process.

- Reaffirms its selection of the Geronimo proposal, and orders Xcel to execute Geronimo's power purchase agreement as revised.

- Selects Calpine's and Xcel's proposals as resources that meet Xcel's remaining need, and approves the terms offered by Calpine and Xcel.

- Declines Invenergy's proposal on the grounds that it does not meet Xcel's needs as efficiently as Calpine's and Xcel's.

II. Background

A. The Proposed Projects

Consistent with the May 2014 Order, Xcel developed terms for the following four proposals:

- Geronimo proposes to erect photovoltaic panels at approximately 24 sites adjoining substations along Xcel's transmission or distribution lines, each site with a capacity of up to 10 megawatts (MW), for an aggregate capacity of up to 100 MW (or 72 MW of accredited capacity) fueled by solar power.

- Xcel proposes to install a 215 MW combustion turbine generator, powered by natural gas, at Xcel's existing Black Dog Generating Station in Burnsville (Black Dog Unit 6). This would be a peaking generator – that is, a generator designed to run only under periods of peak demand for electricity; these generators tend to be less expensive to build, but have relatively high operating costs, including fuel costs.[4]

- Invenergy proposes to install a natural gas combustion turbine generator adjoining its existing 357 MW generator in Cannon Falls. While initially proposing to install a 178.5 MW generator, Invenergy has now committed that generator to another project; Invenergy now proposes a substitute generator with a capacity of 209 MW.[5]

- Calpine proposes to install a gas-powered combined cycle generating plant – that is, a combustion turbine combined with a heat recovery steam generator to extract more energy from each unit of fuel burned. Calpine proposes to build its new Mankato Energy Center II (MEC II) adjoining the existing 375 MW Mankato Energy Center (MEC I). This addition would provide at least 55 MW of peaking capacity plus at least 290 MW of intermediate capacity. Intermediate generators, having higher construction costs but lower operating costs, are designed to run more frequently than peaking generators.[6]

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[4] See, for example, *12-1240 Docket*, Public Hearing Transcript, Vol. 1 at 11-12 (testimony of Xcel witness Alders).

[5] Xcel Compliance Filing (September 23, 2014) at 16.

[6] *Id.*; Xcel proposal (April 15, 2013) at 5-3.

B. Commission Instruction for Power Purchase Agreements and Price Terms

In directing Xcel to finalize draft terms for each of the developer's proposals, the Commission offered the following admonitions:

> *A. Calpine, Geronimo, Invenergy, and Xcel shall be held to the prices and terms used to evaluate each bid for the purpose of cost recovery from Xcel ratepayers. Ratepayers must not be put at risk for costs that are higher than bid or for benefits assumed in bids that do not materialize. If actual costs are lower than bid, the bidders should be allowed to keep those savings.*
>
> *B. The agreements must provide terms that sufficiently protect ratepayers from risks associated with the non-deliverability of accredited capacity and/or energy from the project(s) as proposed.*
>
> *C. The Commission is unlikely to find it reasonable for Xcel to enter into an agreement in which negotiated terms shift risk or unknown costs to ratepayers.*
>
> *D. Delay and cancellation provisions are appropriate considerations for power purchase agreement negotiations.*[7]

C. Xcel's Solar Energy Standard Docket (SES)

On May 23, 2013, the Governor signed a bill establishing Minnesota's Solar Energy Standard (SES), directing investor-owned utilities such as Xcel to acquire sufficient electricity from solar energy to supply 1.5 percent of the utility's total retail electric sales (excluding sales to certain industrial customers) by 2020.[8] By 2020 this policy would require Xcel to acquire an estimated 455,919 megawatt-hours (MWh) of solar energy,[9] or up to 200 MW of accredited capacity.[10]

Xcel has initiated a docket to solicit proposals for solar-powered generators to comply with the Solar Energy Standard (the SES Docket).[11] Both the Department and Xcel have proposed that the Commission defer consideration of Geronimo's proposal to that docket. Xcel aspires to make selections in that docket promptly in order to take advantage of a 30 percent federal investment tax credit, currently due to expire by the end of 2016.[12]

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[7] May 2014 Order, Ordering Paragraph 2.

[8] See 2013 Laws of Minnesota ch. 85, art. 10, § 3, codified at Minn. Stat. § 216B.1691, subd. 2f.

[9] *12-1240 Docket*, ALJ's Report, Finding 14, citing Ex. 57 at 8 (Engelking Direct), citing Xcel Comments, *In the Matter of the Request for Filings From Electric Utilities on Customers Excluded From the Solar Energy Standard*, Docket No. E-999/CI-13-542 at 4 (August 15, 2013).

[10] *12-1240 Docket*, Ex. 46 at 22 (Wishart Direct), Ex. 83 at 19 (Rakow Direct); but see Xcel Reply Comments (November 3, 2014) at 21-22.

[11] See *In the Matter of the Petition of Xcel Energy for the Approval of a Solar Portfolio to Meet Initial Solar Energy Standard Compliance*, Docket No. E-002/M-14-162.

[12] See 26 U.S.C. § 48; after 2016 the tax credit is reduced to 10 percent.

D. The Midcontinent Independent System Operator, Inc. (MISO)

All parties to this proceeding must anticipate and respond to the actions (and inactions) of the Midcontinent Independent System Operator, Inc. (MISO), which administers a regional electric transmission grid operating in parts of Minnesota, Manitoba, and 14 other states. MISO runs a market for bulk energy transactions, selecting the most efficient generators to meet the needs of the participating utilities and large industrial customers. And MISO runs a market for ancillary services, selecting the most efficient generators to hold in reserve for back-up power and balancing momentary fluctuations in supply and demand.

In an effort to maintain the transmission grid's reliability, MISO considers both supply and demand. MISO considers demand when it identifies the amount of capacity each load-serving entity is responsible to provide in order to meet the forecasted levels of peak demand, as well as each entity's reserve requirements – that is, a minimum amount of generating capacity that a utility must have in excess of the projected peak demand for electricity.[13]

MISO considers supply when it establishes policies to estimate, or *accredit*, the amount of power a generator can be expected to provide to meet this demand and reserve requirements. For example, Geronimo determined that under MISO's current policies, Geronimo's proposal would receive accreditation of 72 percent of the generators' nominal capacity of 100 MW. In accrediting the capacity of a gas-powered generator, MISO currently does not consider whether the generator has a firm gas supply – but this policy is currently under review.

MISO recalculates reserve requirements, and reassesses generators' accredited capacity, annually.

Finally, MISO designates the generators that may interconnect to the regional power grid, and establishes the price and schedule under which they may do so. Under MISO's current practices, MISO will not credit the capacity of generators such as those proposed by Calpine and Invenergy until the related transmission facilities have been upgraded – which is not expected until 2019 or 2020.

III. Xcel's Compliance Filing and Recommendation

In its compliance filing, Xcel submitted the draft power purchase agreements it has negotiated with Geronimo, Calpine, and Invenergy, and reaffirmed the terms it has offered for its own Black Dog Unit 6 proposal. But Xcel does not ask the Commission to approve any of these agreements.

Based on its new need assessment, Xcel claims that it will still have an excess 96 MW through 2019, and will not need new capacity until as late as 2024.[14] Xcel attributes this putative change in need to 1) a decline in customer demand, 2) the addition of generating capacity through temporary contracts and delayed plant retirements, and 3) changes in Xcel's assessment of its reserve margin[15] – in effect, freeing up some of Xcel's existing generators to meet customer needs.

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[13] See, for example, *12-1240 Docket*, Ex. 46 at 5 (Wishart direct) (defining "reserve margin").

[14] *12-1240 Docket*, Xcel Compliance Filing (September 23, 2014) at 9.

[15] While MISO has not altered its reserve margin formula since the Commission's prior meeting in this docket, Xcel has altered its assessment of its reserve margin as it has "gained more confidence in the approach…." *12-1240 Docket*, Xcel Compliance Filing (September 23, 2014) at 5.

Given these changes, Xcel proposes that the Commission postpone acting on any of the proposals for gas-powered generators and authorize Xcel to negotiate terms for extending the implementation date for each of these projects into 2019-2021. And Xcel proposes that the Commission "mak[e] the public interest determination required for Geronimo's Aurora PPA in light of the Commission's assessment of the Company's capacity requirements and the availability of the solar PPA proposals that we have developed through our [SES Docket]."[16]

But Xcel acknowledges that its proposals reflect only one means of balancing the various factors at issue in this docket, and that the Commission would be justified in drawing a different conclusion based on a different balancing of the factors.

IV. Need Assessment

A. Positions of the Parties

The Environmental Intervenors support Xcel's recommendation to defer action on all new generators except for Geronimo's. The Environmental Intervenors argue that the Commission's May 2014 Order already selected Geronimo's proposal for implementation, subject only to the condition that the parties agree on terms that are in the public interest. To the extent that the record demonstrates that Xcel has additional needs, the Environmental Intervenors recommend that Xcel pursue additional opportunities for conservation and other forms of managing customer demand.

Geronimo, Invenergy, and Calpine point out that Xcel's new need assessment is internal, unvetted, and introduced too late in this case for adequate examination by other parties. Noting that need assessments inevitably change over time, these parties argue that Xcel's most recent assessment provides an insufficient basis to abandon this docket.

Moreover, the Department joins these developers in emphasizing that the draft power purchase agreements, and Xcel's terms for developing Black Dog Unit 6, offer favorable terms.[17] They caution that these terms are not likely to be available by the time Xcel's need for additional generating capacity is resolved beyond all dispute. In particular, they argue that environmental regulations will prompt utilities to retire their older and coal-powered generators, driving up demand for -- and thus the price of -- new generators. For example, MISO estimates that the federal Mercury and Air Toxics Standards (MATS) will trigger the retirement of 10-12 gigawatts of coal-fired generation by 2016, and the proposed federal Clean Power Plan Proposed Rule (Section 111(d) Rule) could trigger the retirement of an additional 11-14 gigawatts by 2020.[18]

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[16] *12-1240 Docket*, Xcel Reply Comments (November 3, 2014) at 1.

[17] See, for example, *12-1240 Docket,* Hearing Transcript, Volume 1 (October 22, 2013) at 109-110 (Xcel witness Wishart).

[18] MISO Letter to federal Environmental Protection Agency (November 25, 2014); see also *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan,* Docket No. E-002/RP-10-825, Order Establishing Procedural Schedules and Filing Requirements (November 30, 2012) at 5 (discussing consequences of new federal environmental regulations); Environmental Report (October 14, 2013), Appendix C, Xcel response to Department Information Request 1-1 (noting Xcel must retire Black Dog Units 3 and 4, or make expensive changes, to comply with MATS); Ex. 46 (Wishart Direct) at 22.

The Department shares the concerns raised by other parties that Xcel's new need assessment filing left insufficient time for analysis. Nevertheless, the Department reports that it was able to evaluate some of Xcel's alleged changes to its need assessment, including Xcel's proposed short-term capacity additions. On the basis of this partial review the Department now recommends that the Commission defer bringing any new gas-powered generators on-line until 2019 – but no later.

B. Commission Action

The Commission strives to maintain a stable perspective in evaluating a utility's ever-changing need assessment. This starts with noting that Xcel has revised its assessment of need throughout this proceeding. It is entirely foreseeable and unremarkable that Xcel's assessment has changed over time – and indeed, that it will continue to do so.

Because factors affecting need are continually changing, resource decisions must be made in the midst of flux. The weight the Commission gives to an assessment reflects the scrutiny the assessment has received. Xcel's latest need assessment is based on a technically complex analysis that has received much less scrutiny than Xcel's prior assessments.

In support of its recommendation to select none of the current generators proposed to it, Xcel argues that it now forecasts having an excess 96 MW through 2019. Parties dispute Xcel's assessment. But even if Xcel's assessment reflected the soundest data and methods, Xcel's recommendation assumes the Commission should be guided solely by Xcel's statement of MISO's minimum requirements. Moreover, 96 MW represents a margin of less than one percent of Xcel's estimated 9776 MW capacity obligation for 2019 – a rather narrow margin.[19]

Need assessments are necessarily approximate and even the most analytic utilities must plan for a range of outcomes. In this docket the Department has evaluated the consequences of selecting various combinations of generators under multiple scenarios – including a scenario of lower-than-expected demand. In short, Xcel's latest demand forecast, though new, was still within the range of contingencies contemplated and evaluated by the Department.[20]

Finally, the Commission's goal is not to forecast the precise level of need – a task rife with the potential for error – but to identify the resource mix that will best manage forecasting error. As Xcel observed,

> [A] conservative approach [to resource planning] is warranted to ensure adequate generating capacity on our system under all reasonably plausible outcomes. While this may sometimes mean that available capacity will exceed the identified need for a short period of time, this is preferable to incurring a shortfall of capacity. Further, this conservative planning approach insulates our customers from over-reliance on the MISO market due to routine variations in the availability of system resources.[21]

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[19] *12-1240 Docket*, Xcel Compliance Filing (September 23, 2014) at 9 (table).

[20] *12-1240 Docket*, Department comments (October 23, 2014) at 3.

[21] *12-1240 Docket*, Xcel Exceptions to ALJ Report (Jan. 21, 2014) at 6.

Based on the state of the record regarding Xcel's latest need assessment, the Commission will decline to alter its finding of need on this basis. Rather, the Commission reaffirms its finding from its May 2014 Order at 26:

> [T]he Commission will err on the side of ensuring that Xcel has enough capacity to meet the needs of its customers. The future will always be uncertain, but the Commission must proceed to make the necessary choices on the basis of a rigorous analysis of the data that *is* in the record.[22]

That said, Xcel has negotiated draft terms with each of the developers of gas-powered generators that provide the option of postponing the generator's in-service date to as late as 2019. Commission approval of any of these agreements will provide Xcel with the discretion, consistent with the Department's recommendation, to delay operations to that point in time.

But Geronimo, the Department, the Environmental Intervenors, and Xcel itself acknowledge that different factors influence the timing of a solar-powered project. The Commission concurs: The analysis demonstrating the merits of Geronimo's power purchase agreement rests on the assumption that Geronimo would implement its proposal in time to qualify for a 30 percent federal investment tax credit, currently due to expire by the end of 2016. Nothing in Xcel's need analysis alters this dynamic.

V. Geronimo's Aurora Power Purchase Agreement

A. Party Positions

Geronimo and the Environmental Intervenors ask the Commission to approve Geronimo's power purchase agreement, arguing that it complies with the May 2014 Order. And the Department concludes that the terms of Geronimo's agreement are consistent with the public interest and consistent with the prices and terms used to evaluate its bid in this process.

Xcel does not specifically recommend or oppose the Geronimo project. Rather, Xcel recommends referring consideration of Geronimo's proposal to its new SES Docket, thereby facilitating comparisons to rival proposals for solar-powered generators.

B. Agreement Provisions

1. Capacity and Commercial Operation Date

Geronimo proposes to build solar-powered generators with a combined nameplate capacity of 100 MW, and an accredited capacity of at least 71 percent of this amount.

[22] [Fn. 96] Ex. 49 at 7 (Alders Direct) ("[T]here are factors that create uncertainty and could materially affect our resource need assessment. The new need assessment is another data point that should be considered in analyzing which resource proposals should be selected to address the range of [Xcel]'s potential need in the 2017-2019 timeframe.").

Unlike Calpine, Invenergy, or Xcel, Geronimo promises that its proposal would be able to provide power by December 1, 2016.

2. Price, Financial Risk, Operational Risk, Capacity Accreditation

The Department reviewed the draft agreement's terms governing price and promised nameplate capacity, and other matters.

All power purchase agreements involve financial risk, such as the risk that the seller will be unable to deliver power as promised, forcing the utility to acquire other resources at the last minute. They also involve operational risks, such as the risk that the project will be delayed, or shut down in whole or part.

Geronimo's agreement provides a Security Fund to provide some protection against the risk of having to buy replacement power on short notice. And the agreement provides a variety of other remedies, including damage payments if Geronimo fails to have 100 MW installed by the operational date, as well as compensation for failing to gain accreditation of at least 71 percent for the generators' installed capacity. The Department concludes that these terms are consistent with Geronimo's proposal and with providing reasonable protection to ratepayers.

3. Transmission Interconnection

Because the Geronimo project is not designed to interconnect with the MISO transmission system, the project bears no risk related to interconnecting to the transmission grid.

Rather, the project is designed to interconnect with Xcel's distribution system. Because Geronimo has agreed to bear all costs related to interconnecting to the distribution system, the Department concludes that this arrangement poses no unreasonable risks to ratepayers.

4. Environmental Risk

Geronimo's agreement would award all environmental and renewable energy credits arising from this project to Xcel. The Department concludes that this arrangement poses no unreasonable risk to ratepayers.

5. Curtailment

Geronimo's agreement provides for Xcel to compensate Geronimo if, from time to time, Xcel refuses to take delivery of the electricity generated by the project. Curtailments might occur, for example, when a given part of Xcel's electrical system is experiencing a temporary glut of electricity relative to demand. Xcel would not need to compensate Geronimo for curtailments triggered by emergencies.

Xcel states that this part of the agreement is analogous to terms in Xcel's other agreements with renewable generators. In any event, Xcel notes that solar generators tend to provide power during periods of high demand, reducing the likelihood of curtailments.

6. Cost Recovery

During the Commission's meetings on December 8 and 15, 2014, the Commission expressed concerns about language in Article 6.1(A) of Geronimo's agreement governing cost recovery; no other developer has proposed similar language in their agreements. In response to the Commission's concerns, Geronimo and Xcel agreed to modify the contested language in the manner set forth in the Ordering Paragraphs.

In general, the revised language provides for either party to terminate the power purchase agreement if, within a specified timeframe, it is unclear that Xcel can secure assurances of having a reasonable opportunity to recover the share of the project's costs allocated to the Minnesota and North Dakota jurisdictions.

According to Geronimo and Xcel, this language is intended to achieve two competing goals. First, it is intended to maximize Xcel's opportunity to recover the cost of Geronimo's project throughout Xcel's service area. This includes cost recovery from North Dakota, a jurisdiction providing roughly five percent of Xcel's revenues, which may preclude cost recovery of projects undertaken prior to receiving state approval. Second, the cost recovery language is intended to give Geronimo the confidence to make the investments necessary to meet the 2016 in-service date before the 30 percent investment tax credit expires.

VI. Calpine's Mankato Energy Center II Power Purchase Agreement

A. Party Positions

The Environmental Intervenors oppose this proposal, as they oppose the other gas-powered generators offered in this docket, as exceeding Xcel's latest assessment of need.

In contrast, the Department recommends that the Commission approve at least one of the gas-powered proposals – and Calpine's project is the Department's first choice among the proposals in this docket. But the Department acknowledges that concerns about some of the terms of Calpine's power purchase agreement, discussed below, could justify selecting one of the other gas-powered generators instead.

As the sole party to propose a combined cycle plant, Calpine argues that its proposal generates greater benefits for lower cost – including environmental costs – than the other gas-powered proposals. Calpine states that the costs reflected in its draft power purchase agreement reflect the economies of scale Calpine was able to achieve by combining its proposal with its existing Mankato Energy Center. Calpine cautions that these unusually advantageous circumstances are unlikely to arise in the future.

According to the Department, Calpine's generator would prove to be the least-cost choice under a variety of scenarios – if gas prices increase, or regulations increase the cost of generating carbon dioxide, or the retirement of other generators causes Xcel (and MISO) to dispatch the remaining generator more often than anticipated. In analyzing the parties' initial proposals, the Department determined that Calpine's proposal was the single least-cost generator under the Department's base forecast of need. And the Department determined that Calpine's proposal combined with Black Dog Unit 6 formed a package of generators that would permit Xcel to meet its customers' needs at least cost.

But the Department also determined that the dynamics that would make Calpine efficient if gas prices were to rise, or plant utilization would be greater, would also render the proposal less advantageous than the other gas-powered proposals in the event gas prices were to fall or the generator were dispatched less than anticipated.

B. Agreement Provisions

1. Capacity and Commercial Operation Date

Calpine proposes to build a 345 MW combined-cycle generator to provide both peaking and intermediate power.

Like the other developers of gas-powered generators, Calpine reports that it is no longer able to have its new generator ready for operation in 2017. It could meet a 2018 or 2019 in-service date, albeit at slightly higher prices than applied to a 2017 in-service date.

2. Price, Financial Risk, Operational Risk

The Department reviewed the draft agreement's terms governing price and promised nameplate capacity, and concluded that they were consistent with the Calpine proposal.

The draft agreement provides for a Security Fund and other measures to manage financial, operational, and capacity accreditation risk. The Department generally concluded that these safeguards were reasonable.

3. Environmental Risk

The agreement identifies circumstances under which each party might bear some cost of future environmental regulations. Where new regulation of emissions would produce a material adverse effect on the economics of the agreement, the parties agree to cooperate in finding a strategy to mitigate the harm. The Department concludes that these terms are reasonable and consistent with the assumptions used for purposes of comparing the various developers' proposals.

4. Capacity Accreditation

Under the terms of the draft agreement, Xcel would begin making payments to Calpine only when MISO recognizes the generator as a "capacity resource" available to help Xcel meet its system power needs, including Xcel's reserve margins. But before this could occur, MISO must complete its upgrades to certain transmission facilities to provide additional transmission capacity. Only MISO can determine the timing of these events. While Calpine might be able to interconnect with the transmission grid by 2018, it does not expect to secure accredited capacity for its generator before 2019, and perhaps later.

The draft power purchase agreement contains various terms managing risks arising from securing capacity accreditation. If Calpine were to conclude that MISO will not provide an assessment of its generator's capacity in time to meet the agreement's in-service date, the draft agreement authorizes Calpine to postpone the date. The power purchase agreement also provides terms to compensate Xcel if Calpine, when it finally receives accreditation, fails to achieve the promised level of generating capacity.

5. Transmission Interconnection

Generators seeking to interconnect with the transmission grid must pay the transmission interconnection cost established by MISO. This practice creates two uncertainties: uncertainty about the magnitude of the costs, and uncertainty about when MISO will establish the relevant costs. Calpine reports that MISO has not yet established the transmission interconnection cost for its proposed project.

Under the draft agreement, Xcel would bear these transmission interconnection costs. Calpine estimated that MISO would allocate transmission costs of $650,000 to $1.5 million to the Calpine project, and the Department used the $1.5 million figure when comparing the cost-effectiveness of the Calpine proposal to other alternatives.

The Department offers no opinion about the appropriate magnitude of the risk. Rather, the Department concludes that allocating this risk to Xcel, and hence to ratepayers, is inconsistent with the Commission's May 2014 Order admonishing negotiators that the terms of the power purchase agreements should not place such risks on ratepayers.

Calpine defends the agreement's allocation of interconnection costs on various grounds. First, Calpine argues that Xcel, being the more experienced party, is in the better position to assess and bear the risk.

Second, Calpine argues that the manner in which the parties have evaluated Calpine's proposal has mitigated the interconnection risk. In modeling the costs and benefits of Calpine's initial proposal, the Department imputed a cost of $1.5 million for interconnection. The fact that Calpine's proposal remains cost-competitive relative to other proposals suggests that it delivers $1.5 million in benefits beyond the benefits of the competing proposals. In effect, the power purchase agreement would pay Xcel $1.5 million to bear this interconnection risk; if interconnection costs less than $1.5 million, Xcel and ratepayers retain the benefit.

Third, Calpine argues that the interconnection costs are not unbounded. The agreement provides for Xcel to cancel the agreement (albeit with cancellation fees) if the costs grow too high.[23]

6. Dispatchability Payments

Calpine's agreement provides for Xcel to make dispatchability payments to Calpine. Generally, dispatchability payments provide a financial incentive for a power plant operator to maximize the capacity the generator has available to respond when dispatched, and to maximize the promptness and speed with which the generator responds to signals to change output levels.[24] These are not uncommon terms, appearing in both Calpine's power purchase agreement with Xcel, and in Invenergy's draft agreement.[25] According to the Department, while the magnitude of this payment

[23] *12-1240 Docket*, Xcel Compliance Filing (September 23, 2014), Attachment A (draft MEC II power purchase agreement), Article 2 (Term and Termination).

[24] *Id.*, Attachment A (draft MEC II power purchase agreement), Section 8.2 (Payment for Dispatchability).

[25] See *id.*, Attachment B (draft Invenergy Cannon Falls II power purchase agreement), Section 8.2 (Payment for Dispatchability).

is designated a trade secret, the net effect of this term would be to “slightly increase[] the total expected capacity payments” to Calpine.[26]

The Department objects to this provision -- not because of its magnitude, but because it represents a type of charge that was not included in Calpine’s initial proposal, and thus was not incorporated into the calculations comparing the cost-effectiveness of the various proposals.

Calpine and Xcel argue that this added term would benefit all parties. Xcel sought this change to make the payment structure for Calpine’s new generator mirror Xcel’s payments structure for the existing Mankato Energy Center generator – a structure that the Commission has already approved. According to Calpine, a more uniform pricing structure would better enable Xcel to offer the combined plant’s capacity into the MISO ancillary services markets via automatic generation control, making the facility more nimble and useful – and able to generate more revenues.

In addition, Xcel negotiated other changes to offset the advantage that this change would bring to Calpine. For example, the draft language eliminated bonus payments, requires Calpine to obtain a subordinated mortgage on the facility for Xcel, grants a Right of First Offer in the event Calpine were to propose to sell the original Mankato Energy Center I, and grants the right to assume Calpine’s duties and prerogatives if Calpine were to default (“step-in rights”).

VII. Invenergy’s Cannon Falls Power Purchase Agreement

A. Party Positions

The Environmental Intervenors oppose this proposal, as they oppose the other gas-powered generators offered in this docket, as exceeding Xcel’s latest assessment of need.

In contrast to Calpine’s agreement, the Department praises Invenergy’s draft power purchase agreement for refraining from shifting costs or risks to ratepayers that were not part of its initial bid. It does, however, expose Xcel to the risk of a fuel supply interruption, discussed below.

According to the Department, Invenergy’s proposal proves to be the least-cost generator under scenarios in which demand for electricity is lower than anticipated, and when the generator selected in this docket is dispatched less often than anticipated. However, it compares less favorably under scenarios in which gas prices are lower than anticipated, or if the generator were required to operate more often than anticipated. And when the Department identified the least-cost package of generators to meet Xcel’s forecasted need, Invenergy’s proposal was not part of the package.

B. Agreement Provisions

1. Capacity and Commercial Operation Date

Invenergy proposes to build a 209 MW peaking generator.

[26] Department comments (October 23, 2014) at 15.

Like the other developers of gas-powered generators, Invenergy reports that it is no longer able to have its new generator ready for operation in 2017. It could meet a 2018 or 2019 in-service date, albeit at slightly higher prices than applied to a 2017 in-service date.

2. Price, Financial Risk, Operational Risk, Capacity Accreditation

The Department reviewed the draft agreement's terms governing price and promised nameplate capacity, and concluded that they were consistent with Invenergy's proposal.

The draft agreement provides for a Security Fund and other measures to manage financial, operational, and capacity accreditation risk. The Department generally concluded that these safeguards were reasonable.

3. Transmission Interconnection

As with Calpine's proposal, Invenergy's proposal cannot interconnect with the transmission grid until MISO completes necessary grid improvements. Invenergy would not expect to interconnect and secure accredited capacity for its generator before 2019, and perhaps later. As with Calpine's proposal, this proposal manages that risk for the generator by permitting the developer to postpone the project's agreed-upon in-service date without penalty.

Unlike Calpine's proposal, Invenergy's proposal bears 100 percent of the cost of interconnecting to the transmission grid. The Department concludes that this arrangement imposes no unreasonable risk to ratepayers.

4. Environmental Risk

The agreement identifies circumstances under which each party might bear some cost of future environmental regulations. The Department concludes that these terms are reasonable and consistent with the assumptions used for purposes of comparing the various developers' proposals.

5. Dispatchability

As with Calpine's agreement, Invenergy's agreement provides for Xcel to make dispatchability payments. Unlike Calpine, Invenergy had included this provision in its initial proposal, and these payments therefore did not represent a change from the proposal as submitted.

6. Fuel Supply

Invenergy's proposal provides for Xcel to acquire either firm or interruptible sources of natural gas to power the plant. Contracting for an interruptible supply would save money, but expose the project to the risk that the utility's gas supply would be interrupted, especially during the winter when demand for natural gas grows higher. For purposes of developing a cost comparison with other proposals, the estimated cost of the Invenergy proposal incorporated the cost of contracting for an interruptible gas supply.

Invenergy offers three reasons to conclude that this risk is reasonable. First, the period of highest demand for natural gas is during the winter when the MISO system has excess generating capacity. Second, Invenergy proposes to have on site a 28-hour supply of fuel oil to use in the event that the gas supply is interrupted. Third, MISO accredits the capacity of generators that rely on interruptible sources of fuel, indicating that MISO does not regard this arrangement as excessively risky.

The Department notes, however, that MISO has been reconsidering its policy regarding the accreditation of generators relying on interruptible sources of gas.

VIII. Xcel's Black Dog Unit 6 Price Terms

A. Party Positions

The Environmental Intervenors oppose this proposal, as they oppose the other gas-powered generators offered in this docket, as exceeding Xcel's latest assessment of need.

According to the Department's analysis, Black Dog Unit 6 is Xcel's least-cost alternative under a variety of scenarios, including if gas costs are lower than forecast, or the unit is dispatched less often than anticipated. Conversely, Black Dog Unit 6 performs less well than other generators under scenarios in which the cost of natural gas, or of carbon emissions, is higher, or if the unit is dispatched more than anticipated.

Based on its analysis of all the generators, the Department concludes that if the Commission were to select two gas-powered generators, one of them should be Black Dog Unit 6. But as previously noted, if the Commission were to select only one gas-powered generator, the Department would recommend Calpine's generator instead.

B. Agreement Provisions

The May 2014 Order directed Xcel to develop price terms for its proposal in lieu of a draft power purchase agreement. These terms address many of the same issues addressed in the power purchase agreements, including the following:

1. Capacity and Commercial Operation Date

Xcel proposed to build a 215 MW combustion turbine generator providing peaking power.

Like the other developers of gas-powered generators, Xcel reports that it is no longer able to have its new generator ready for operation in 2017. It could meet a 2018 or 2019 in-service date.

2. Transmission Interconnection

Xcel expects Unit 6 would be able to interconnect with the transmission grid as early as 2018 using the accredited transmission capacity of Black Dog Units 3 and 4, which Xcel plans to retire in 2015. Consequently, Xcel argues, the Commission can have confidence that Black Dog Unit 6, unlike the proposals of Calpine or Invenergy, will be able to secure interconnection rights promptly.

3. Cost Recovery and Term

In its May 2014 Order, the Commission admonished the negotiating parties that ratepayers should not be put at risk for costs that are higher than bid, but that bidders would be allowed to retain the savings if actual costs prove to be lower than bid. This language applies to the Black Dog Unit 6 proposal differently than to the other proposals, in that 1) Xcel would own this project rather than contract for it, and 2) Xcel estimates that the project would last longer than 20 years.

Xcel first addresses cost: Consistent with the first part of the Commission's admonition, Xcel states that it will forgo recovery of any costs that exceed its proposal (plus financing costs). But distinct from the second part of the admonition, Xcel states that it would not seek to recover from ratepayers more than the project's actual costs, plus financing costs, even if this proves to be less than the amount of Xcel's bid.

Xcel then addresses benefits: To the extent that Black Dog Unit 6 operates beyond the 20 years analyzed for purposes of comparing the developer's proposals, ratepayers would derive the benefit of retaining Unit 6's capacity without necessarily incurring additional capital costs. In contrast, while it may be possible to extend the term of a power purchase agreement, it would come at additional cost.

The Department concludes that these proposed terms are reasonable.

IX. Commission Analysis and Action

A. Summary

Having reviewed the parties' arguments, the Commission reaffirms its selection of Geronimo's proposal and directs Xcel to execute Geronimo's draft power purchase agreement.

To meet the rest of Xcel's needs, the Commission also selects the power purchase agreement offered by Calpine – largely due to its operational efficiency and economies of scale -- and the terms offered by Xcel – largely due to its ability to interconnect and provide flexible energy on a timely basis.

B. Geronimo Proposal

1. Referral to Xcel's SES Docket

On April 15, 2013, Geronimo submitted its proposal to build a collection of solar generators distributed throughout Minnesota. Ever since, parties have periodically requested that the Commission refer this proposal to Xcel's SES Docket.[27] Nevertheless, the proposal has remained in the current docket, was recommended by the administrative law judge, and was selected by this Commission subject to review of the power purchase agreement's terms. Simply put, Geronimo's proposal fit squarely within the criteria of Xcel's request for proposal and deserves to be considered alongside the other proposals.

In any event, it is not obvious that the proposals being considered in the SES Docket are comparable to Geronimo's proposal. In the current docket, Xcel solicited proposals to provide *capacity* in the near-term; in the SES Docket, Xcel solicited proposals to provide *energy* by 2020, the focus of the Solar Energy Standard. Thus Geronimo's proposal offered to provide

[27] See, for example, *12-1240 Docket*, Ex. 46 at 36 (Wishart Direct), Ex. 83 at 12-13 (Rakow Direct).

MISO-accredited levels of power to Xcel's system by 2016, and to bear financial consequences if the solar project fails to perform. The SES Docket was not designed to elicit this type of proposal.

For the foregoing reasons, the Commission will decline to refer consideration of Geronimo's project to a different docket. Instead, the Commission will evaluate Geronimo's power purchase agreement in the context of the current docket.

2. Commission Action

In its May 2014 Order, the Commission directed Xcel to negotiate a draft power purchase agreement with Geronimo, and to submit the agreement for Commission review to ensure that the negotiated terms are consistent with the public interest.[28] A variety of factors prompted the Commission to select Geronimo's project:

> [T]he ALJ's Report demonstrates the merits of Geronimo's proposal, both for supporting the reliability and adequacy of Xcel's power supply, but also for promoting beneficial environmental and socioeconomic outcomes. In particular, the Commission notes the state policy favoring energy from renewable sources,[29] and the goal of reducing greenhouse gases relative to 2005 levels by 30 percent by 2025 and 80 percent by 2050.[30] Geronimo's proposal best advances these policies.
>
> The principal objection to Geronimo's proposal has been cost. But whether an analysis shows Geronimo's proposal to be more expensive than the other proposals, or less expensive, or similar in cost, depends on the value given to solar energy, S-RECs [solar renewable energy credits], externality values, and other factors. While the Department's analysis found other proposals to be more cost-effective, the difference in the cost of Geronimo's proposal and other proposals was less than half a percent.
>
> Weighing all factors explored in this record, the Commission affirms the ALJ's recommendation and will select Geronimo's proposal.[31]

The Commission affirms these findings. Geronimo's proposal offers unique benefits. For example, only Geronimo's proposal would connect to Xcel's distribution system, thereby alleviating rather than exacerbating transmission line congestion. And only Geronimo states that it can implement its proposal by the beginning of 2017, the first year specified in the docket's request for proposal.

The Department concludes that Geronimo's agreement is generally consistent with Geronimo's proposal and the prices and terms used to evaluate Geronimo's bid in this proceeding. The agreement maintains the project's in-service date. The price has remained the same. And the agreement does not place Xcel's ratepayers at risk for more cost than Geronimo included in its

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[28] May 2014 Order at 36.

[29] Minn. Stat. 216B.2422, subd. 4.

[30] Minn. Stat. 216H.02.

[31] May 2014 Order at 34 (some citations omitted).

initial proposal; indeed, the agreement specifies that Geronimo bears the risk if the generators fail to deliver the promised generating capacity.

While the proposed agreement does not shift costs to Xcel or ratepayers, it does add language addressing how Xcel would recover the cost of this project. Geronimo and Xcel explain that these terms were prompted by the need to manage a potential conflict of state policies within the time constraints of an expiring federal tax credit. The Commission concludes that these terms, as revised through these proceedings, promote the interest of Minnesota ratepayers by enhancing the likelihood that Xcel will recover the cost of the Geronimo project from ratepayers throughout Xcel's operations, and from the tax credit.

The Commission finds that Geronimo's power purchase agreement is consistent with its initial proposal, does not put ratepayers at undue risk, and is consistent with the public interest. Consequently the Commission will approve it.

C. Proposals for Gas-Powered Generators

1. Introduction

Throughout this docket, analytical models developed by the Department and Xcel have identified combinations of three natural gas projects -- Calpine's Mankato Energy Center II proposal, Invenergy's Cannon Falls II proposal, and Xcel's Black Dog Unit 6 proposal – as providing Xcel with the least-cost means to fulfill Xcel's established need for more power. To aid the Commission's selection among these alternatives, the Commission directed the developers of these projects to finalize the terms of their proposals.

Having reviewed the filings, the Commission finds that the terms offered for all of these proposals are generally consistent with the prices and terms used to evaluate the proposals in this proceeding.

Moreover, the Commission finds that these terms are consistent with the public interest. The Commission concurs with the Department and the developers that the offered terms appear quite economical by historical standards. This fact, combined with forecasts of plant retirements due to new regulations, persuade the Commission to authorize Xcel to lock in these favorable terms on behalf of ratepayers.

Nevertheless, the Commission found that Xcel might require up to 500 MW of additional capacity by 2019. The Commission anticipates Geronimo providing 72 of those MW, leaving a need for up to 428 MW. This is enough demand to justify contracting for two, but not three, of the gas-powered generators under consideration.

Again, the Department recommends that the Commission secure the services of at least one of the gas-powered generators. If the Commission were to select only one, the Department would recommend Calpine's; if two, the Department would recommend the combination of Calpine's and Xcel's. The Commission concurs.

2. Calpine

Calpine provides the greatest flexibility of any of the proposals under consideration. It offers both peaking and intermediate power. With at least 345 MW, it offers the greatest capacity of any single generator. And this capacity could be coordinated with the capacity provided by the existing Mankato Energy Center, which Xcel already has under contract.

Calpine's economies of scale permit it to operate with the lowest operating cost (including lowest carbon emissions) per unit of output of the gas-powered alternatives.

Calpine's generator would prove to be the least-cost choice under a variety of scenarios – if gas prices increase, or regulations increase the cost of generating carbon dioxide, or the retirement of other generators causes Xcel (and MISO) to dispatch the remaining generator more often than anticipated. In analyzing the parties' initial proposals, the Department determined that Calpine's proposal was the single least-cost generator under the Department's base forecast of need. And the Department determined that Calpine's proposal combined with Black Dog Unit 6 formed a package of generators that would permit Xcel to meet its customers' needs at least cost.

Moreover, the Commission finds the terms of Calpine's power purchase agreement to be reasonable, even with respect to transmission costs and dispatchability payments. This is so, notwithstanding the Commission's admonitions that "[r]atepayers must not be put at risk for costs that are higher than bid" and that "[t]he Commission is unlikely to find it reasonable for Xcel to enter into an agreement in which negotiated terms shift risk or unknown costs to ratepayers."[32]

With respect to Calpine's transmission interconnection language, the negotiated agreement does not alter the terms initially established in Calpine's proposal – that is, the terms under which the Department determined Calpine's proposal to be the most cost-effective. Moreover, Calpine and Xcel are sophisticated, competing parties negotiating an arm's length transaction. There is nothing inherently unreasonable with Xcel bearing a portion of a generator's interconnection costs as part of a power purchase agreement, especially when the agreement has a cancelation clause. Consequently the Commission finds insufficient reason to second-guess their transmission interconnection terms at this time.

Calpine's proposed dispatchability payments, in isolation, would shift costs to ratepayers. However, the magnitude of these costs is not unknown; it is reasonably clear and quantified. Moreover, when these payments are evaluated not in isolation, but within the context of the larger agreement, they are eminently reasonable. According to Calpine and Xcel, these payments are 1) common in the industry, 2) small in proportion to other considerations, 3) motivated by a desire to coordinate the operations of both halves of the Mankato Energy Center, creating economies of scale and the potential to generate offsetting revenues, and 4) offset by other concessions. Thus the Commission finds that the *net* costs of these terms, evaluated in context, are reasonable and consistent with Calpine's overall proposal.

[32] May 2014 Order, Ordering Paragraph 2.

That said, the dispatchability terms were not included in the initial calculation of Calpine's costs, and the quantification of costs and benefits were not well developed in the record. Consequently the Commission will require this matter to be addressed when Xcel seeks to recover the costs of the Calpine project.

3. Xcel's Black Dog Unit 6

As previously noted, Black Dog Unit 6 is Xcel's least-cost generator under a variety of scenarios, including if gas costs are lower than forecast, or the unit is dispatched less often than anticipated.

Xcel's proposal offers attractive terms, including the option of retaining the benefits of any construction savings, and the option of continuing to derive useful life from the plant beyond its first 20 years. But its most unique attribute is that Black Dog Unit 6 has the option of providing dispatchable capacity by 2018 due to its ability to use the transmission capacity from some of Xcel's retiring generators. By selecting Black Dog Unit 6, the Commission builds a higher degree of security into Xcel's generation portfolio.

4. Invenergy

As previously discussed, the terms of Invenergy's proposal are consistent with the public interest and consistent with the prices and terms used to evaluate its bid in this process. Moreover, Invenergy proves to be the least-cost generator under scenarios in which demand for electricity is lower than anticipated, and when the generator selected in this docket is dispatched less often than anticipated. However, it compares less favorably under scenarios in which gas prices are lower than anticipated, or if the generator were required to operate more often than anticipated. And when the Department identified the least-cost package of generators to meet Xcel's forecasted need, it did not include Invenergy's proposal as part of the package.

The Department concluded that Invenergy's proposal was competitive with the other proposals in this docket – under the assumption that Invenergy would operate with an interruptible gas supply. Securing fuel on an interruptible basis is cheaper, but exposes the generator to a risk that the fuel supply would be cut off, especially during periods of peak demand for natural gas. It is unclear how well a 28-hour supply of fuel oil would offset this risk, especially in extreme cold when demand for gas is likely to be at its highest. And prospectively, it is unclear how MISO will accredit generators that rely on interruptible gas supplies.

5. Commission Action

In selecting the gas-powered generators to meet the remainder of Xcel's needs, the Commission strives to identify a portfolio that will provide the best combination of benefits at least cost. In brief, the Commission finds that Calpine's proposal provides the greatest operational flexibility and lowest operating costs, while Xcel's proposal provides the greatest reliability in securing an energy source with transmission access. These generators, combined with Geronimo's proposal, meet all the capacity needs demonstrated on the record.

For the foregoing reasons, the Commission will select Calpine's Mankato Energy Center II power purchase agreement and Xcel's Black Dog Unit 6, subject to its price terms, as resources that fit Xcel's need. Consequently the Commission will approve the power purchase agreement and the price terms. For the same reasons, the Commission will decline to select Invenergy's proposal.

The Commission will so order.

ORDER

1. Regarding Geronimo's proposal:

   A. The Commission selects the proposal as a resource that fits Xcel's need and approves the power purchase agreement between Xcel and Aurora Distributed Solar, LLC, as set forth in Xcel's compliance filing of September 23, 2014, modified to substitute the following language for the original language in Article 6.1(A), as well as for the language in Exhibit A, "State Regulatory Agency(s)" and "State Regulatory Approval":

   Article 6 – CONDITIONS PRECEDENT

   6.1 <u>Company CPs</u>.

   (A) On September 23, 2014, Company filed an unexecuted draft of this PPA with the Minnesota Public Utilities Commission pursuant to the requirements of the Order. No later than ten (10) Days after receipt of an order from the Minnesota Public Utilities Commission authorizing Company to execute this PPA, Company shall file this PPA with the North Dakota Public Service Commission. Seller shall cooperate with Company's effort to seek State Regulatory Approval.

   (B) Either Party shall have the right to terminate this PPA, without any further financial or other obligation to the other as a result of such termination, by Notice to the other Party not more than ten (10) Days after the earlier of: (i) fourteen (14) Days after receipt of written determinations by both State Regulatory Agencies that together do not constitute State Regulatory Approval, or (ii) six (6) months following the written request for State Regulatory Approval without receipt of State Regulatory Approval. If a Party fails to terminate this PPA in the time allowed by this paragraph, such Party shall be deemed to have waived its right to terminate this PPA under this Section 6.1 and this PPA shall remain in full force and effect thereafter.

   Exhibit A -- DEFINITIONS

   "State Regulatory Agency(s)" means the Minnesota Public Utilities Commission or any successor agencies in the State of Minnesota and the North Dakota Public Service Commission or any successor agencies in the State of North Dakota.

   "State Regulatory Approval" means a final, written order of one State Regulatory Agency, or if needed, both State Regulatory Agencies, that does not impose conditions unsatisfactory to the Company and is not subject to application for rehearing, re-argument and reconsideration,

and that makes the affirmative determination that Company's execution of this PPA is prudent and/or in the public interest, and that those costs incurred by Company under this PPA as presently allocated by ratemaking mechanisms to Company's Minnesota and North Dakota jurisdictions are recoverable, in the aggregate, from the Company's Minnesota and/or North Dakota retail customers. The preceding is subject only to the requirement that the State Regulatory Agency retains ongoing prudency review of Company's performance and administration of this PPA.

B. Xcel shall execute Geronimo's power purchase agreement as amended and, within 10 days of the Commission's order in this matter, make a compliance filing with the executed power purchase agreement.

2. Regarding Calpine's proposal:

A. The Commission selects the proposal as a resource that fits Xcel's need and approves Xcel's draft power purchase agreement with Mankato Energy Center II, LLC.

B. In any request to recover costs related to this project, Xcel shall address the costs and benefits of the dispatchability payments.

3. Regarding Xcel's Black Dog 6 proposal, the Commission selects the proposal as a resource that fits Xcel's need and approves the price terms.

4. The Commission declines to select Invenergy's proposal.

5. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf
Executive Secretary

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Decision No. C16-0548-I

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 16A-0117E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF THE 600 MW RUSH CREEK WIND PROJECT PURSUANT TO RULE 3660(H), A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE RUSH CREEK WIND FARM, AND A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE 345 KV RUSH CREEK TO MISSILE SITE GENERATION TIE TRANSMISSION LINE AND ASSOCIATED FINDINGS OF NOISE AND MAGNETIC FIELD REASONABLENESS.

PROCEEDING NO. 16V-0314E

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A VARIANCE OF THE CONSTRUCTION SCHEDULE FOR THE PAWNEE TO DANIELS PARK 345 KV TRANSMISSION PROJECT.

INTERIM DECISION ADDRESSING INTERVENTIONS, CONSOLIDATING PROCEEDINGS, GRANTING RULE WAIVERS, SETTING FILING DATES, ESTABLISHING DISCOVERY PROCEDURES, SCHEDULING PREHEARING CONFERENCE, GRANTING PROTECTIVE ORDER, REQUIRING FILINGS, AND EXTENDING DEADLINE FOR DECISION

Mailed Date: June 17, 2016
Adopted Date: June 15, 2016

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I. BY THE COMMISSION

A. Statement

1. This Decision grants, with modifications, the Motions to Adopt Procedural Schedule, to Expedite Review of the Application, and Requesting Waivers (Procedural Motion) filed by Public Service Company of Colorado (Public Service or Company) on May 13, 2016, in Proceeding No. 16A-0117E. We grant the requests for permissive interventions and consolidate Proceeding Nos. 16A-0117E and 16V-0314E, as discussed below. We also grant, in part, a motion for protective order filed by Public Service.

2. Answer Testimony in this consolidated matter shall be filed no later than July 27, 2016. Rebuttal Testimony and Cross-Answer Testimony shall be filed no later than August 22, 2016. All prehearing motions shall be filed no later than August 29, 2016, and responses to

prehearing motions shall be filed no later than September 1, 2016. Final post-hearing statements of position shall be filed no later than September 19, 2016.

3. A prehearing conference is scheduled for September 2, 2016. Hearings in this consolidated matter are scheduled for September 7 through 9, 2016, consistent with Decision No. C16-0423-I, issued May 19, 2016.

4. Public Service shall file a modified Non-Disclosure Agreement in accordance with our approval, in part, of its Motion for Protective Order no later than five days following the effective date of this Decision. Public Service also shall file supplemental Direct Testimony addressing the Pawnee-Daniels Park Project no later than 21 days following the effective date of this Decision, consistent with the discussion below. Finally, Public Service shall file an amended application and amended Direct Testimony to remove its request for the Commission to establish a baseline and methodology to determine the potential level of net economic benefits for a potential future request for "extra profits" under 4 *Code of Colorado Regulations* (CCR) 723-3-3660(g) of the Rules Regulating Electric Utilities, consistent with the discussion below. The amended application and revised testimony shall be filed no later than 21 days following the effective date of this Decision.

B. Rush Creek Wind Project Application

5. On May 13, 2016, in Proceeding No. 16A-0117E, Public Service filed an Application for Approval of the 600 MW Rush Creek Wind Project, Certificate of Public Convenience and Necessity for the Rush Creek Wind Farm, and a Certificate of Public Convenience and Necessity for the 345 kV Rush Creek to Missile Site Generation Tie Transmission Line (Rush Creek Wind Project Application).

6. Public Service states that the Rush Creek Wind Project will include 300 Vestas model V110 wind turbines, which will be built in Colorado and have a nameplate capacity of 2 MW each. The project will comprise two wind farms (Rush Creek I and II) and a new 90-mile 345 kV transmission tie line to interconnect with the Company's system at the Missile Site Substation. Public Service estimates that the total cost of the project will be $1.036 billion: $915 million is the projected construction costs of the wind generation facilities and $121.4 million is the cost of the transmission tie line.

7. Invenergy Wind Development North America, LLC (Invenergy) currently is developing the Rush Creek I and II sites. Public Service has entered into a Purchase and Sale Agreement for the sites, such that when they are "construction-ready" and meet other conditions precedent to closing, the Company will acquire a 100 percent equity stake in both. Public Service explains that the opportunity to partner with Invenergy enables the project to take advantage of the full benefits of the federal Production Tax Credit (PTC) for wind generation facilities.

8. Public Service seeks seven specific items from the Commission:

1) Approval to develop, own, and operate the Rush Creek Wind Project pursuant to § 40-2-124(1)(f)(I), C.R.S., and Rule 3660(h);
2) A Certificate of Public Convenience and Necessity (CPCN) for Rush Creek I and II;
3) A CPCN for the Rush Creek 345 kW transmission tie line;
4) Findings on noise and magnetic fields for the transmission tie line;
5) Approval of a cost recovery proposal pursuant to § 40-2-124(1)(f)(IV), C.R.S., and Rule 3660(i);
6) Approval of a baseline and calculation methods for potential future use by the Company to earn an "extra profit" on the project pursuant to § 40-2-124(1)(f)(II), C.R.S., and Rule 3660(g); and
7) Approval of four supporting studies, including the Coal Cycling Cost Study, Flex Reserve Adequacy Study, Wind Effective Load Carrying Capacity Study, and Wind Integration Study.

9. In its Procedural Motion, Public Service states that it is necessary for the Commission to issue a final decision on the proposed Rush Creek Wind Project by November 10, 2016 in order for the Company to meet the safe harbor requirements of the maximum PTC to apply.

C. Pawnee-Daniels Park Project Variance Petition

10. On April 29, 2016, in Proceeding No. 16V-0314E, Public Service filed a Petition for Variance of Commission Decision for Accelerated Construction Schedules (Pawnee-Daniels Park Project Variance Petition). Through its Petition, Public Service seeks a variance to the Pawnee-Daniels Park Project construction schedule ordered in Decision Nos. R14-1405 issued November 25, 2014, and C15-0316 issued April 9, 2015.[1]

11. The Pawnee-Daniels Park Project includes a new 345 kV transmission line between the Pawnee Generating Station and the Daniels Park Substation, a new Harvest Mile Substation, and a new 345 kV circuit from Smoky Hills to Daniels Park.

12. Decision No. R14-1405 established, and Decision No. C15-0316 affirmed, a construction schedule allowing Public Service to begin work on the Pawnee-Daniels Park Project no earlier than May 1, 2020. In its Petition, Public Service seeks to begin the project in 2017, with an in-service date of October 30, 2019.

13. Public Service states that there is a need for an expedited construction schedule, as evidenced by eight interconnection study requests for interconnection at the Missile Site Substation. The Company states that four of the study requests were withdrawn after the need for the Pawnee-Daniels Park Project was identified by studies. Additionally, Public Service

[1] Proceeding No. 14A-0287E.

asserts that the expedited construction schedule will allow the Company, and its rate payers, to take advantage of the PTC available for wind renewable energy resources.

D. Procedural Background

14. On May 2, 2016, we issued a Notice of Petition Filed requiring pleadings to become a party in Proceeding No. 16V-0314E to be filed no later than June 1, 2016.

15. On May 18, 2016, the Colorado Office of Consumer Counsel (OCC) filed a Notice of Intervention of Right and Request for Hearing in Proceeding No. 16V-0314E. The OCC also filed a Motion to Consolidate, requesting that the Commission combine Proceeding Nos. 16A-0117E and 16V-0314E.

16. On May 19, 2016, we set the Rush Creek Wind Project Application for hearing before the Commission *en banc* and scheduled the evidentiary hearing for September 7 through September 9, 2016.[2] We agreed with Public Service that expedited procedures are necessary given the potential benefit to the Company's customers from capturing the full federal PTC for wind resources should the Commission approve the acquisition of the Rush Creek Wind Project and issue CPCNs for Rush Creek I, Rush Creek II, and the interconnecting transmission tie line. We also shortened the notice and intervention period for Proceeding No. 16A-0117E. Intervention filings were due on June 1, 2016. Persons seeking intervention were allowed to respond to Public Service's Procedural Motion in their requests for intervention or other pleadings due on June 1, 2016.

[2] Decision No. C16-0423-I, issued May 19, 2016, Proceeding No. 16A-0117E.

17. On May 27, 2016, we set response time to the OCC's Motion to Consolidate to June 1, 2016, consistent with the intervention period for Proceeding No. 16V-0314E and the shortened intervention period for Proceeding No. 16A-0117E.[3]

18. We deemed the Rush Creek Wind Project Application complete on June 8, 2016.

E. Public Service Motion for Leave to Reply to Staff and WRA

19. Public Service seeks to reply to certain aspects of the responses to the Company's Procedural Motion submitted by Western Resource Advocates (WRA) and the Staff of the Colorado Public Utilities Commission (Staff). Specifically, Public Service requests an opportunity to reply to WRA's proposals for discovery and to WRA's recommendations for the severing from this proceeding the issues surrounding the calculation of net economic benefits and "extra profits" pursuant to § 40-2-124(1)(f)(II), C.R.S., and Rule 4 CCR 723-3-3660(g). Public Service also seeks leave to respond to Staff's request that the Commission strike the portions of the Company's Rush Creek Wind Project Application and Direct Testimony related to the "extra profit" matter.

20. Public Service states that it has reached an accommodation with WRA on the discovery issue and argues that the suggestion of WRA and Staff that the "extra profit" issue be severed from this proceeding is, in effect, a motion. Public Service argues that it is appropriate for the Commission to grant leave for it to reply to "this newly raised procedure."

21. We agree that Public Service should have an opportunity to respond to WRA and Staff on these points and grant Public Service's Motion for Leave to Reply.

[3] Decision Nos. C16-0458-I and C16-0459-I, issued May 27, 2016, Proceeding Nos. 16V-0314E and 16A-0117E, respectively.

F. Interventions

1. Rush Creek Wind Project Application

a. Discussion

22. Staff, the OCC, and the Colorado Energy Office (CEO) each filed notices of intervention by right.

23. Staff states that it will attempt to independently verify Public Service's assertions that the Rush Creek Wind Project, if built, will provide significant cost savings to customers. Staff intends to review the assumptions used by the Company in both its Strategist modeling work and worksheet calculations. Staff does not, through its intervention filing, state whether it opposes or supports the Application.

24. The OCC states that it is concerned about certain issues presented by Public Service. Within its filing, the OCC states specific concerns, including whether the Rush Creek Wind Project Application meets statutory and rule requirement standards. Consistent with the standard required in § 40-2-124(1)(f), C.R.S., the OCC states it intervenes to review whether the costs associated with the project are reasonable compared to the cost of similar eligible energy resources available in the market.

25. CEO states that it is statutorily mandated to promote renewable energy resource development in Colorado. CEO claims that Public Service's Rush Creek Wind Project Application, if approved, will increase wind generation in the state, which CEO supports.

26. Invenergy requests to participate as an *amicus curiae*. Invenergy states that the projects that are the subject of the Rush Creek Wind Project Application are being developed by two of its wholly owned subsidiaries. Invenergy requests that it be permitted to provide legal analysis in this proceeding to assist the Commission, including whether the projects satisfy the

requirements of § 40-2-124(1)(f), C.R.S., and Rule 4 CCR 723-3-3660(h). No party filed response to Invenergy's request and it is therefore unopposed.

27. Several potential parties requested permissive intervention, including: Holy Cross Electric Association, Inc., Yampa Valley Electric Association, Inc., Intermountain Rural Electric Association, and Grand Valley Rural Power Lines, Inc. (jointly, Joint Cooperatives); the City of Boulder (Boulder); Tri-State Generation and Transmission Association, Inc. (Tri-State); Climax Molybdenum Company and CF&I Steel, L.P. (jointly, Climax/CF&I); Interwest Energy Alliance (Interwest); Colorado Energy Consumers (CEC); the City and County of Denver (Denver); Southwest Generation Operating Company, LLC (SWGen); WRA; Rocky Mountain Environmental Labor Coalition (RMELC) and Colorado Building and Construction Trades Council, and AFL-CIA (CBCTC) (jointly, RMELC/CBCTC); Colorado Independent Energy Association (CIEA); Sustainable Power Group, Inc. (sPower or Sustainable Power); and a coalition of ratepayers (Ratepayer Coalition). Each has argued that its interests would not otherwise be adequately represented without intervention in this matter.

28. The Joint Cooperatives are each a cooperative electric association. The Joint Cooperatives state that each purchases a substantial portion of its wholesale electric power and energy from Public Service through a purchase power contract that may be affected by the outcome of Proceeding No. 16A-0117E. They expect that the proposed Rush Creek Wind Project will have an impact on the generating resource allocations of each cooperative, which will create a rate impact for its member-customers.

29. Boulder states that it is a large customer of Public Service that has historically participated in most of the Company's resource acquisition proceedings. Boulder states that it "applauds" Public Service's efforts to shift from fossil fuels. Nevertheless, Boulder states that,

because it has created a municipal electric utility, it has an interest in ensuring its departure from the Company's system is taken into account when the acquisition of new generation facilities are being considered.

30. Tri-State states that Public Service's proposed transmission line will tie into the interconnected transmission system that includes Tri-State assets. Tri-State argues that the proposal therefore may affect Tri-State operations of its transmission system and its plans for use of the interconnected transmission system.

31. As Public Service's largest retail electric customers, Climax/CF&I claim that the Rush Creek Wind Project Application, if approved, may affect retail rates substantially, including their electricity costs, and "possibly the reliability" of the service necessary to provide mining and steel production.

32. Interwest is a Colorado nonprofit corporation and a trade association of wind, utility-scale solar, and other renewable energy project developers and equipment manufacturers. Because the project is the largest renewable energy project in Colorado to date, Interwest states that Proceeding No. 16A-0117E, including the vetting of the wind and reserve studies, will affect its members' businesses through purchase power agreements (PPAs) and engineering, planning, and construction contracts.

33. CEC is an association of large industrial and commercial customers. CEC states that its "members are generally supportive of the purported economic and environmental benefits that the Project may provide."[4] However, CEC states that the Rush Creek Wind Project

[4] CEC Motion to Intervene at ¶ 4.

Application, if approved, will have a direct and substantial impact on CEC's interests and the electricity charges made by its members.

34. Denver notes that it routinely participates in Public Service proceedings and "supports [Public Service's] effort to develop, own, and operate clean energy resources."[5] Denver purchases electricity from Public Service through a franchise agreement and states that, because it and its citizens will be affected by the proposal, the city intends to address ratepayer impacts and compliance with renewable energy requirements.

35. SWGen is an independent power producer (IPP) with generation facilities in Colorado and its corporate office in Denver. SWGen states that it has a direct interest in securing and renewing PPAs and bidding for new generation development opportunities. SWGen states that Proceeding No. 16A-0117E will affect those interests in particular because the flexible resource and wind integration studies included in the study will be used to inform economic analysis of bids in the Company's Electric Resource Plan (ERP).

36. WRA is a nonprofit conservation organization "dedicated to protecting the land, air and water of the West."[6] WRA claims that the wind generation facilities proposed would deliver significant zero-carbon electricity to the grid in Colorado. WRA states that it supports Public Service's Rush Creek Wind Project Application and that Proceeding No. 16A-0117E will have a direct impact on its tangible interest in reducing the environmental effects of electricity generation.

37. RMELC/CBCTC notes that it was recently granted intervention status in Proceeding No. 16D-0168E, a precursor to Proceeding No. 16A-0117E. RMELC/CBCTC claims

[5] Denver Motion to Intervene at ¶ 5.

[6] WRA Petition for Leave to Intervene at 1.

that Proceeding No. 16A-0117E will have an impact on future resource planning proceedings where it intends to participate to advocate for its interest in labor and the environment.

38. CIEA is a non-profit corporation and trade association of IPPs with a mission to foster the competitive acquisition of cost-effective resources for the benefit of its members and Colorado ratepayers. CIEA states that it intends to understand and confirm the transmission line proposals made in the Rush Creek Wind Project Application and to ensure the propriety and effectiveness of the studies being reviewed in this proceeding that it expects will be integral to the ERP. CIEA further states that it intends to advocate for Commission decisions that safeguard competitive bidding of renewable resources and market participation of IPPs.

39. The Ratepayer Coalition is an unincorporated association of electricity consumers served by Public Service, comprised of individuals, businesses, and nonprofit associations.[7] The Ratepayer Coalition seeks intervention "to obtain the most economical, reliable electricity that complies with state and federal law…."[8] The Ratepayer Coalition also states that the project threatens multiple species of birds and bats. The Ratepayer Coalition states that its interests are not adequately represented in Proceeding No. 16A-0117E, specifically because it claims that Staff is statutorily charged with exploring and promoting alternative energy development and that the OCC "is charged by statute primarily with promoting an undefined 'public interest' and only secondarily with promoting the security and economic interest of ratepayers…."[9]

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[7] The Motion to Intervene filed by the Ratepayer Coalition on June 1, 2016 identifies the following members: Wells Trucking, Wells Ranch, Westlake Wine and Spirits, Auto Collision Specialists, Leanin' Tree Cards, 88 Drive in Theater, Independence Real Estate Network, Kelsey Alexander, Lou Schroeder, Peg Brady, and Mary Dabman. An amended Motion to Intervene was filed by the Ratepayer Coalition on June 6, 2016 to include the Independence Institute and to remove Peg Brady as members.

[8] Ratepayer Coalition Motion to Intervene at ¶ 4.

[9] *Id. at* ¶ 1.

40. Sustainable Power opposes the Rush Creek Wind Project Application and requests intervention. Sustainable Power states that it is an IPP that owns or operates more than 150 utility and distributed electrical generation systems across the United States and the United Kingdom, and that it focuses on utility scale renewable energy projects. Sustainable Power argues that the Rush Creek Wind Project will reduce the opportunities that IPPs, including developers of qualifying facilities (QFs) such as sPower, will have to sell power to the Company. Sustainable Power further states that the Rush Creek Wind Project Application is a "significant issue" because it may detrimentally impact sPower's ability to exercise its right under the federal Public Utilities Regulatory Policies Act (PURPA) to sell QF energy and capacity to the Company.

41. Within its Motion for Leave to Reply, Public Service states that it does not object to any of the petitions for intervention. However, the Company states that sPower raises issues beyond the scope of this proceeding. Specifically, Public Service claims that sPower's objections regarding Commission rules implementing PURPA are beyond the scope of this proceeding.

b. Findings and Conclusions

42. Public Service, the applicant, is a party to Proceeding No. 16A-0117E.

43. Staff, the OCC, and CEO are each intervenors as of right and are each a party to Proceeding No. 16A-0117E.

44. We grant Invenergy leave to participate as *amicus curiae*, consistent with Rule 4 CCR 723-1-1200(c) of the Commission's Rules of Practice and Procedure. Invenergy may provide legal argument within this proceeding; however, it is not a party and no arguments presented by Invenergy shall be considered evidence or included as part of the evidentiary record.

45. Rule 4 CCR 723-1-1401(c) states in relevant part:

> A motion to permissively intervene shall state the specific grounds relied upon for intervention; the claim or defense within the scope of the Commission's jurisdiction on which the requested intervention is based, including the specific interest that justifies intervention; and why the filer is positioned to represent that interest in a manner that will advance the just resolution of the proceeding. The motion must demonstrate that the subject proceeding may substantially affect the pecuniary or tangible interests of the movant (or those it may represent) and that the movant's interests would not otherwise be adequately represented. … The Commission will consider these factors in determining whether permissive intervention should be granted. Subjective, policy, or academic interest in a proceeding is not a sufficient basis to intervene.

46. In addition, Rule 4 CCR 723-1-1401(c) requires additional discussion for certain motions representing ratepayer interests:

> If a motion to permissively intervene is filed in a natural gas or electric proceeding by a residential consumer, agricultural consumer, or small business consumer, the motion must discuss whether the distinct interest of the consumer is either not adequately represented by the OCC or inconsistent with other classes of consumers represented by the OCC.

47. As set forth in §§ 40-6.5-104(1) and (2), C.R.S., the OCC has a statutory mandate to represent the "public interest," and "to the extent consistent" with the public interest, interests of certain ratepayers. The Colorado Supreme Court stated that "if there is a party charged by law with representing his interest, then a compelling showing should be required to demonstrate why this representation is not adequate." *Feigen v. Alexa Group, Ltd.*, 19 P.3d 23, 26 (Colo. 2001).

48. Pursuant to Rule 4 CCR 723-1-1500, the person seeking leave to intervene by permission bears the burden of proof with respect to the relief sought.

49. Each of the entities seeking to intervene that does not represent residential consumer, agricultural consumer, or small business consumer interests has demonstrated that Proceeding No. 16A-0117E may substantially affect its pecuniary or tangible interests pursuant

to Rule 1401(c). Each also has demonstrated that its interests would not otherwise be adequately represented. Accordingly, we grant intervenor status to the Joint Cooperatives, Boulder, Tri-State, Climax/CF&I, Interwest, CEC, Denver, SWGen, WRA, RMELC/CBCTC, CIEA, and sPower.

50. With respect to the Ratepayer Coalition, we permit permissive intervention. While in this instance the OCC's stated reasons for its intervention as of right include many of same interests stated by the Ratepayer Coalition, it is within our discretion to allow the Ratepayer Coalition to intervene and to participate as a party. Ratepayer Coalition's motion meets the minimum requirements of Rule 1401(c). Among our considerations for granting the request, we note that no objection was filed to the Ratepayer Coalition's intervention. Ratepayer Coalition's inclusion in the proceeding as a party representing certain ratepayer interests will not unduly prejudice any other party to the proceeding or expand the scope of this proceeding. In this instance, we grant the Ratepayers Coalition's permissive intervention.

51. The Joint Cooperatives, Boulder, Tri-State, Climax/CF&I, Interwest, CEC, Denver, SWGen, WRA, RMELC/CBCTC, CIEA, sPower, and the Ratepayer Coalition are parties to Proceeding No. 16A-0117E.

52. We expect all participating parties to focus their arguments, as relevant, on the Rush Creek Wind Project Application at issue in Proceeding No. 16A-0117E. The parties are advised that we will not permit extraneous arguments beyond the scope of this proceeding. Parties also shall not use this proceeding to challenge final Commission decisions. *See* §§ 40-6-112(2), C.R.S. ("[i]n all collateral actions or proceedings, the decisions of the commission which have become final shall be conclusive.").

53. We also find it prudent to balance the interests of multiple-party participation with administrative efficiency. Due to the expedited schedule anticipated in this proceeding and the number of parties permitted to intervene, parties should coordinate efforts, when feasible. We request parties make joint filings or indicate concurrence rather than making duplicative filings, when, for example, the Ratepayer Coalition's interests are aligned with those of the OCC.

2. Pawnee-Daniels Park Project Variance Petition

a. Discussion

54. The OCC filed an intervention of right in Proceeding No. 16V-0314E and requests a hearing. The OCC argues that the request to approve the Pawnee-Daniels Park Project Variance Petition is premature and is largely dependent on approval the Rush Creek Wind Project Application. The OCC also states that it is concerned with Public Service's statement that the Company has had multiple requests for interconnection for renewable energy generation that would require the use of the Pawnee-Daniels Park Project's facilities. The OCC claims that the Company has provided very little information about these multiple requests received for interconnection since 2013.

55. Staff also filed an intervention of right in Proceeding No. 16V-0314E and requests a hearing. Staff states that, on May 6, 2016, it requested that Public Service provide a construction schedule in support of the requested variance. Staff also expressed to the Company the need to understand the impact of the Rush Creek Wind Project and the associated generation tie transmission line to the Pawnee-Daniels Park transmission line. Staff alleges that the Company failed to produce the requested information requested and that the relationship between the Rush Creek Wind Project and associated generation tie transmission line to the Pawnee-Daniels Park still needs to be demonstrated by the Company.

56. CEC seeks to intervene in Proceeding No. 16V-0314E and requests a hearing. CEC argues that Public Service is asking the Commission "to depart from its thoughtful and balanced decision in Proceeding No. 14A-0287E by waiving the primary ratepayer protection embedded in the CPCN for the Project: namely, a construction date beginning not before 2020."[10] CEC contends that it has significant concerns with the Pawnee-Daniels Park Project Variance Petition, including the fact that the "need" described by the Company now is vastly different from the evidence of need that was provided in Proceeding No. 14A-0287E. CEC states that the Company's "reliance on the incentive-driven Rush Creek Wind Project, which is not needed to serve load, as the basis to unwind the ratepayer protections embedded in the CPCN for the [Pawnee-Daniels Park] Project is particularly troubling for the Company's captive customers, including CEC's members."[11]

57. Interwest supports the petition and requests intervention for the opportunity to participate as a party in the event a hearing is scheduled.

b. Findings and Conclusions

58. Public Service, the petitioner, is a party to Proceeding No. 16V-0314E.

59. Staff and the OCC are each intervenors as of right and are each a party to Proceeding No. 16V-0314E.

60. We find that CEC and Interwest have each demonstrated that the Pawnee-Daniels Park Variance Petition may substantially affect its pecuniary or tangible interests pursuant to Rule 4 CCR 723-1-1401(c). Each also has demonstrated that its interests would not otherwise be adequately represented. We therefore grant intervenor status to Interwest and CEC.

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[10] CEC Petition to Intervene ¶10.

[11] *Id.* at ¶ 11.

61. Interwest and CEC are parties to Proceeding No. 16V-0314E.

G. OCC Motion to Consolidate Proceedings

62. The OCC argues that the consolidation of proceedings for the Rush Creek Wind Project Application and the Pawnee-Daniels Park Variance Petition is warranted, because the implementation of the Rush Creek Wind Project depends on the proposed modified construction schedule of the Pawnee-Daniels Park Project. The OCC also contends that consolidation will allow judicial economy and the elimination of potentially duplicative activity by the Commission and parties to the proceedings.

63. The OCC states that it conferred with Public Service regarding the consolidation of the two proceedings and that Public Service indicated that it would not oppose the OCC's Motion to Consolidate if, in the case of consolidation, supplemental testimony could be filed in Proceeding No. 16A-0117E.

64. Staff supports the Motion to Consolidate.

65. We find good cause the grant the Motion to Consolidate under Rule 4 CCR 723-1-1402. The issues in Proceeding Nos. 16A-0117E and 16V-0314E are substantially similar and the rights of the parties to both cases will not be prejudiced by consolidation. We agree with the OCC that the combination of the proceedings for a single hearing is more efficient for the Commission and the intervening parties. We also find that consolidation of the two cases will not impair our ability to render a decision on the Rush Creek Wind Project Application in accordance with the expedited procedures requested by Public Service.

66. Public Service, Staff, the OCC, CEO, the Joint Cooperatives, Boulder, Tri-State, Climax/CF&I, Interwest, CEC, Denver, SWGen, WRA, RMELC/CBCTC, CIEA, sPower, and

the Ratepayer Coalition are parties to this consolidated matter. Invenergy may participate as an *amicus curiae* in the consolidated cases.

H. Public Service Motion for Waivers from Certain ERP Rules

67. Public Service requests waivers from certain ERP Rules found at 4 CCR 723-3-3600, *et seq*. Public Service argues that it is necessary for the Commission to reconcile various inconsistencies between Rules 4 CCR 723-3-3611(e), 3612(e), and 3615(a)(II) and the filing requirements, procedures, and considerations for an application filed pursuant to Rule 4 CCR 723-3-3660(h) of the Commission's Renewable Energy Standard (RES) Rules.

68. Public Service explains that Rule 4 CCR 723-3-3611(e) requires a utility to file a CPCN application when it proposes within an ERP an "alternative method of resource acquisition" other than competitive bidding. Public Service states that it wanted to file the Rush Creek Wind Application as soon as possible and therefore the Company's requests for CPCNs for the Rush Creek Wind Project were not filed simultaneously with the Company's ERP.[12] Public Service further states that, given the time constraints and nature of the alternatives analysis the Company conducted for the requested CPCN for Rush Creek I and II, it was not feasible to quantify and to present the costs of alternatives in the form described in Rule 4 CCR 723-3-3611(e).

69. Public Service states that both Rules 4 CCR 723-3-3660(h)(V) and 3612(e) require an Independent Evaluator (IE) when a utility proposes a method of resource acquisition other than competitive bidding. Public Service states that the requirement of Rule 4 CCR 723-3-3612(e) is duplicative and unnecessary.

[12] Public Service filed its ERP on May 27, 2016 in Proceeding No. 16A-0396E.

70. With respect to Rule 3615(a)(II), Public Service argues that there is a timing issue, because the Company's ERP will not be decided until after the Commission renders a decision on the Rush Creek Wind Project Application.

71. Public Service states that, while the Commission generally has authority to waive its rules, § 40-2-124(1)(f)(I), C.R.S., and Rule 4 CCR 723-3-3660(h)(VI) expressly acknowledge the Commission's authority to waive any Commission rule, providing that nothing "shall prevent the Commission from waiving, repealing, or revising any Commission rule in a manner otherwise consistent with applicable law."

72. Staff, WRA, and the Joint Cooperatives do not object to the request.

73. The OCC filed no statement either supporting or opposing the requested waivers. However, in its intervention filing in Proceeding No. 16A-0117E, the OCC indicated that it wanted to investigate through discovery whether the waivers from the ERP Rules requested by Public Service should be approved.

74. Boulder states that it understands the benefit of resolving the Rush Creek Wind Application proceeding quickly. Nevertheless, Boulder states it is concerned that the project is being considered outside the parameters of an ERP.

75. CEC urges the Commission to reject the Company's requested waiver of Rule 4 CCR 723-3-3611(e) and instead require the Company to provide detailed estimates of the cost of the proposed facility and information on alternatives studied, costs for those alternatives, and explanation of the criteria used to rank or eliminate those alternatives. CEC argues that this detailed information as required by the rule is a necessary ratepayer protection, both because it would support the Company's position that the project "can be constructed at a reasonable cost

compared to the cost of similar eligible energy resources available in the market"[13] and because it would provide additional basis for concluding that the rates that may ultimately result from the project are just and reasonable. CEC acknowledges the Public Service does not need to subject the project to competitive bidding; nevertheless, according to CEC, neither ratepayers nor the Commission can assess the merits of the project without a meaningful comparison of the available alternatives.

76. Sustainable Power also opposes the Company's request for a waiver of Rule 4 CCR 723-3-3611(e). Sustainable Power argues that Public Service's rule waiver requests disregard for Commission decisions implementing its ERP Rules, which, sPower contends, require a utility application filed pursuant to Rule 4 CCR 723-3-3660(h) to be filed in conjunction with an ERP. Sustainable Power further recommends that the Commission withhold ruling on the Company's rule waiver requests at this time; according to sPower, the requested waivers "raise significant issues that should not be decided on the basis of comments provided in motions to intervene alone."[14]

77. Sustainable Power agrees with CEC that, although such utility-owned generation may be exempt from competitive bidding requirements, the Commission needs reference points to understand whether the cost of a proposed resource is "reasonable," taking into account how the proposed resource compares to other resources "available in the market." Sustainable Power warns that the Commission will be ill equipped to evaluate the reasonableness of the Rush Creek Wind Project if it does so without a meaningful understanding of the cost of alternatives that are available in the market.

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[13] CEC Response at 3 (underscoring omitted).
[14] Sustainable Power Motion to Intervene at ¶ 13.

78. We would have preferred that Public Service had proposed to develop and to own the Rush Creek Wind Project as part of its ERP in Proceeding No. 16A-0396E. However, as explained above, the circumstances surrounding the federal PTC support our consideration of the Rush Creek Wind Project in a separate proceeding on an expedited basis. Moreover, Public Service is permitted to file a separate application under Rule 4 CCR 723-3-3660(h).

79. CPCNs are required for Public Service to move forward with the Rush Creek Wind Project. However, we disagree with CEC and sPower that the same showings required for a CPCN submitted with an ERP pursuant to Rule 4 CCR 723-3-3611(e) are necessary pursuant to, and consistent with, Rule 4 CCR 723-3-3660(h). The standard Public Service must meet for the CPCNs requested in the Rush Creek Wind Project Application is whether the project "can be constructed at reasonable cost compared to the cost of similar eligible energy resources available in the market." § 40-2-124(f)(1), C.R.S.; *see also* Rule 4 CCR 723-3-3660(h).

80. We grant Public Service a waiver from Rule 4 CCR 723-3-3611(e) and advise the Company that this waiver in no way reduces its burden to demonstrate that the costs of the Rush Creek Wind Project are reasonable as compared to alternative projects that are obtainable in the market.

81. No parties responded specifically to the request for waivers from Rules 4 CCR 723-3-3612(e) and 3615(a)(II). We agree with Staff that the ERP Rules and the RES Rules do not fit together perfectly and find good cause to grant these waivers as well.

I. Public Service Motion to Adopt Procedural Schedule

82. In its Procedural Motion, Public Service proposes filing deadlines that lead to an evidentiary hearing for September 7 through 9, 2016. The Company's proposed filing deadlines include July 15, 2016, for Answer Testimony and August 15, 2016, for Rebuttal Testimony.[15] Final statements of position (SOPs) would be filed no later than September 19, 2016, to accommodate a final decision no later than November 10, 2016.

83. Boulder and the Joint Cooperatives state that they accept the procedural schedule proposed by Public Service.

84. Staff recommends that the deadline for filing Answer Testimony be revised to July 22, 2016, a week later than proposed by the Company. Staff argues that Public Service chose to file its application on May 13, 2016, while requesting an expedited review and Commission decision by November 10, 2016. The Company only proposes to provide Staff and other intervening parties until July 15, 2016, to conduct discovery, perform analysis, and prepare testimony. In light of the expedited nature of the proceeding, Staff recommends the Commission keep August 15, 2016, as the filing date for the Company's Rebuttal Testimony.

85. WRA argues that the procedural schedule proposed by Public Service will present significant hardship to it and likely many other parties due to multiple conflicts with the established procedural schedule in Proceeding No. 16AL-0048E, the Company's Phase II Electric Rate Case. WRA states, for example, that intervenors would be required to submit Answer Testimony in this proceeding on the same day that Cross-Answer Testimony is due in the rate case and that Cross-Answer Testimony and Rebuttal Testimony would be filed in the midst

[15] Cross-Answer Testimony filed by intervening parties is typically due the same day as an applicant files Rebuttal Testimony.

of the rate case's evidentiary hearing. WRA states that, had Public Service allowed discovery to commence in early June, the Answer Testimony deadline would have to be moved up from July 15, 2016, to July 11, 2016, and the Cross-Answer Testimony and Rebuttal Testimony deadlines could have been changed from August 15, 2016, to August 8, 2016.

86. Sustainable Power opposes the Company's request to expedite this proceeding alleging that it would inflict prejudice to it and other competitive IPPs. Sustainable Power recommends that the Commission order Public Service to confer with the parties on a procedural schedule that is acceptable to all parties.

87. Sustainable Power also argues that Public Service's case for expediency, *i.e.*, to take advantage of the full value of the federal PTC for wind, is misleading and distracting. For instance, sPower argues that Public Service could meet the safe harbor for PTC qualification even if a final Commission decision is not issued by November 10, 2016, by purchasing substation equipment that the Company will need regardless of whether the Rush Creek Wind Project is eventually approved.

88. With respect to discovery, Public Service proposes a seven-day turnaround on discovery requests directed at the Rush Creek Wind Project Application filing and a five-day turnaround for discovery directed at Answer Testimony and Rebuttal Testimony. A cutoff on discovery service would fall on August 29, 2016, and responses would be provided to all requests no later than September 1, 2016.

89. Staff does not oppose the Company's proposals for discovery response times and cut-offs.

90. WRA also does not oppose the accelerated discovery deadlines proposed by Public Service. However, WRA requests the Commission provide additional guidance

concerning discovery procedures. Specifically, WRA requests the Commission require the following: (1) if a party will be unable to respond to a discovery response by the Commission-established deadline, counsel for the responding party shall confer with counsel for the requesting party, in writing, no later than the due date; (2) as part of this conferral, counsel for the responding party shall state the reason for the delay in responding to the discovery request and the anticipated date of production; and (3) if a discovery response is more than three days late, the responding party must file a Motion with the Commission seeking leave to deviate from the Commission's established procedural schedule. (This requirement may be waived upon consent of the requesting party.)

91. In response to WRA's suggestions regarding discovery, Public Service proposes that the Commission adopt an expedited process to address motions to compel. Specifically, the Company proposes that the Commission require responses to any motions to compel to be filed within five business days. Public Service also states that, in this proceeding, the Company is willing to respond to any motions to compel within three business days. Public Service states that, upon conferral, WRA has agreed to this proposal in lieu of its recommendations described above, so long as the Company agrees to confer with a party if an extension of time to respond to discovery request(s) is necessary.

92. We agree that additional time should be afforded to the intervening parties in light of the start date of discovery in this matter and that the deadline for the filing of Answer Testimony should be extended by at least a week from the date proposed by Public Service. We also seek to modify filing deadlines as to avoid filing deadlines in other ongoing proceedings. Therefore, we adopt the following filing deadlines and discovery procedures.

1) Discovery shall be conducted in accordance with Rule 4 CCR 723-1-1405 unless modified by this Decision.

2) Discovery shall commence for all parties no later than the effective date of this Decision.

3) Responses to discovery directed at Public Service shall be provided within seven days.

4) Answer Testimony shall be filed no later than July 27, 2016.

5) Responses to discovery requests directed at Answer Testimony shall be provided within five days.

6) Rebuttal Testimony and Cross-Answer Testimony shall be filed no later than August 22, 2016.

7) Responses to discovery requests directed at Answer Testimony shall be provided within three days.

8) Discovery service shall terminate on August 29, 2016.

9) Responses shall be provided to all outstanding discovery requests no later than September 1, 2016.

Final SOPs shall be filed no later than September 19, 2016.

93. We will adopt the expedited procedures for motions to compel offered by Public Service and accepted by WRA. Responses from an intervening party to any motion to compel directed at the intervening party shall be filed within five business days. Responses from Public Service to any motion to compel directed at the Company shall be filed within three business days. We are concerned about the alleged delays in discovery responses in other proceedings and advise Public Service that motions to compel directed at the Company may put the September hearing dates in jeopardy and could cause a delay in our rendering of a final decision.

94. We scheduled the three-day evidentiary hearing from September 7, 2016, through September 9, 2016, prior to the filing of most of the requests for intervention, the filing of OCC's Motion to Consolidate, and the filing of the responses to Public Service's Procedural Motion. In light of the large number of parties to these consolidated cases and the potential amount of testimony that may be provided with respect to both the Rush Creek Wind Application and the Pawnee-Daniels Park Variance Petition, it is necessary to schedule a prehearing conference prior

to the first day of hearings to ensure an efficient and fair process. For the same reasons, we also find it necessary to set a deadline for the filing of prehearing motions, such as dispositive motions, motions to strike testimony, and motions to approve stipulations and settlement agreements.

95. All prehearing motions shall be filed no later than August 29, 2016. Responses to prehearing motions shall be filed no later than September 1, 2016.[16]

96. A prehearing conference shall be scheduled for September 2, 2016. Public Service shall confer with the parties to develop an exhibit list and an order of witnesses with estimated cross-examination times for presentation at the prehearing conference.

J. Public Service Motion for Protective Order

97. Public Service requests restricted access to certain documents and information, including: (1) commercial contracts and terms, including but not limited to pricing, that is highly sensitive to both Public Service and the vendors that Public Service is transacting with to develop the Rush Creek Wind Project; (2) the Company's Balance of Plant estimates for work used to obtain future bids; and (3) any land rights acquisition costs and estimates. Public Service requests that the Commission provide extraordinary protection for this information, and order that it be treated as highly confidential.

98. Public Service proposes limiting access to the information claimed to be highly confidential to the Commission, Commission Staff, the OCC, and their counsel, as well as counsel and certain subject matter experts (SMEs) for intervenors, with the exception of intervenors that are "developers of energy resources, including potential bidders into Public

[16] Due to these tight deadlines, we recognize that it may be necessary to afford parties an opportunity to provide oral argument on prehearing motions at the prehearing conference.

Service's upcoming ERP proceeding, and any competitive power producers, existing or potential wholesale customers of developers of energy resources, and any trade organization or other association representing any of the foregoing entities would not have access to the highly confidential information."[17] Counsel and the SMEs for eligible intervenors would be required to execute the highly confidential non-disclosure agreements (NDAs) in the form of the attachment to the Company's Motion for Protective Order.

99. Public Service states that the level of highly confidential protection sought here, *i.e.*, denying access to competitors and their trade associations, was previously ordered in the Company's Clean Air – Clean Jobs Act (CACJA) proceeding, Proceeding No. 10M-245E. Public Service states that, in the CACJA proceeding, the Commission entered a protective order denying competitors and their trade organizations—including CIEA—access to competitively sensitive bids provided to Public Service in response to a competitive solicitation.

100. In response, CIEA argues that, as a trade organization, it "nearly exclusively, is to be excluded from reviewing the highly confidential information"[18] and that this preclusion is not appropriate. CIEA states that its counsel and SMEs do not share highly confidential information received among its members. CIEA claims that the Commission's confidentiality rules adequately protect this type of information from public disclosure, similar to ERP proceedings, competitive solicitations, and other proceedings with commercially sensitive information. CIEA requests that its counsel and SMEs who sign appropriate NDAs be allowed the same access as all other parties to the case who are not themselves competitors of Public Service.

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[17] Public Service Motion for Protective Order at ¶ 5c.

[18] CIEA Motion to Intervene at ¶ 14.

101. We grant the Motion for Protective Order, in part. The information Public Service claims to be highly confidential will be protected as such. However, access to this information will be governed by the same disclosure procedures used for ERP proceedings pursuant to Rule 4 CCR 723-3-3614. The information claimed to be highly confidential will be restricted to parties' counsel and SMEs who have signed the necessary NDAs, attesting that they must not only follow the Commission's protective provisions and that the information shall not be used or disclosed for purposes of business or competition, or for any purposes other than for purposes of this proceeding. The Commission, Commission Staff, the OCC, and their counsel also will have access to the information, consistent with Public Service's request.

102. We will follow the established provisions in the ERP Rules because they will serve to provide us with potentially better information and argument with respect to whether the Rush Creek Wind Project "can be constructed at reasonable cost compared to the cost of similar eligible energy resources available in the market." § 40-2-124(f)(1), C.R.S. At that same time, these provisions will maintain the necessary protections of the information, consistent with legislative changes and ERP Rules enacted after the CACJA. Competitive use of the information will be prohibited just as in an ERP proceeding.

K. Staff Motion to Strike the "Extra Profit" Issue from Proceeding

103. In its Notice of Intervention of Right and Request for Hearing filed on May 17, 2016, in Proceeding No. 16A-0117E, Staff included a preliminary response to the Company's Procedural Motion, suggesting that some of Public Service's requested approvals are more expansive than necessary or appropriate for the Commission to consider in an expedited proceeding. For example, Staff stated that it is concerned that the Company is requesting the Commission to establish a baseline of how the net economic benefits (NEBs) from the proposed

Rush Creek Wind Project will be calculated for future filings pursuant to § 40-2-124(1)(f)(II), C.R.S., and Rule 4 CCR 723-3-3660(g).

104. In its full response to Public Service's Procedural Motion, Staff requests that the Commission summarily reject Public Service's request that the Commission establish a baseline and methodology to be used in the future to determine the potential level of NEBs. Staff argues that the Company's proposal is untenable, because it is contrary to the clear and straightforward definition of NEBs set forth in Rule 4 CCR 723-3-3660(g). Staff requests that the Commission state that the Company's proposal is outside the scope of this proceeding and, for clarity of the record, and to order all portions of the application and testimony that pertain to this NEB proposal be stricken.

105. WRA agrees with Staff's suggestion, arguing that the establishment of an NEB baseline in this proceeding is beyond the necessary scope of the expedited proceeding. WRA suggests that reserving this issue for a future proceeding will streamline this proceeding and ensure the Commission can meet the Company's requested expedited schedule. WRA argues that this "extra profit" issue is nonetheless important, because it could have a significant impact on the Company's Renewable Energy Standard Adjustment (RESA) and hence the availability of RESA funds to support future additional renewable resource acquisitions. According to WRA, a future proceeding on this issue will ensure the Commission and stakeholders have sufficient time, attention, and resources to give the issue.

106. More generally, CEC suggests that the Commission should narrowly tailor the scope of this proceeding to enable as thorough and focused a review, investigation, and analysis of the Rush Creek Wind Project in the timeframe allotted.

107. In its reply to WRA and Staff, Public Service states that it has no objection to the suggestions of Staff and WRA that the NEBs issue be considered separately in order to streamline this proceeding. However, the Company states that it does not waive its statutory right to pursue "extra profits" and will file a follow-on application immediately after this proceeding and request that the Commission take administrative notice of the record in this proceeding, assuming the Commission approves the Rush Creek Wind Project. Public Service argues that the use of a follow-on application to adjudicate the "extra profit" issue is consistent with Rule 4 CCR 723-3-3660(g)(I).

108. We accept Public Service's offer to remove the consideration of a baseline and methodology for determining NEBs in this proceeding. We agree with Staff and WRA that this action will help streamline this proceeding given its expedited timeline. We direct Public Service to file an amended application and modified Direct Testimony that conforms to the Company's offer to withdraw the "extra profit" issue from this proceeding. The amended application and modified testimony shall be filed no later than 21 days following the effective date of this Decision.

L. Extension of Decision Deadline

109. Pursuant to § 40-6-109.5, C.R.S., a final decision in this matter must issue no later than October 6, 2016, or 120 days following the date the Rush Creek Wind Project Application was deemed complete, unless that deadline is extended by a separate decision.

110. The procedural schedule we have adopted will enable us to enter a final decision before November 10, 2016, as requested by the Company. However, the October 6, 2016 statutory deadline will not likely be met, since the evidentiary hearings will be held in September.

111. Accordingly, we find good cause to extend the deadline for a final decision another 90 days pursuant to § 40-6-109.5, C.R.S. The 210-day statutory deadline is January 4, 2017.

II. ORDER

A. It Is Ordered That:

1. The Petition for a Variance of the Construction Schedule for the Pawnee to Daniels Park 345 kV Transmission Project (Pawnee-Daniels Park Project) filed by Public Service Company of Colorado (Public Service) on April 29, 2016 in Proceeding No. 16V-0314E is set for hearing before the Commission *en banc*.

2. The Motion to Consolidate filed by the Colorado Office of Consumer Counsel (OCC) on May 18, 2016 in Proceeding Nos. 16V-0314E and 16A-0117E is granted, consistent with the discussion above.

3. Proceeding No. 16A-0117E with respect to the Application for Approval of the Rush Creek Wind Project Pursuant to Rule 3660(h) and a Certificate of Public Convenience and Necessity for the 345 kV Rush Creek to Missile Site Generation Tie Transmission Line filed by Public Service on May 13, 2016 is consolidated with Proceeding No. 16V-0314E. Proceeding No. 16A-0117E shall serve as the primary proceeding.

4. Public Service shall file supplemental Direct Testimony addressing the Pawnee-Daniels Park Project no later than 21 days following the effective date of this Decision, consistent with the discussion above.

5. Staff of the Colorado Public Utilities Commission is a party in this consolidated matter.

6. The OCC is a party in this consolidated matter.

7. The Colorado Energy Office is a party in this consolidated matter.

8. The Petition to Intervene filed by the Colorado Energy Consumers (CEC) on May 20, 2016 in Proceeding No. 16V-0314E is granted.

9. The Motion to Intervene filed by CEC on June 1, 2016 in Proceeding No. 16A-0117E is granted.

10. CEC is a party in this consolidated matter.

11. The Petition to Intervene filed by the Interwest Energy Alliance (Interwest) on May 31, 2016 in Proceeding No. 16A-0117E is granted.

12. The Petition to Intervene filed by Interwest on May 31, 2016 in Proceeding No. 16V-0314E is granted.

13. Interwest is a party in this consolidated matter.

14. The Motion to Intervene filed jointly by Holy Cross Electric Association, Inc.; Yampa Valley Electric Association, Inc.; Intermountain Rural Electric Association; and Grand Valley Rural Power Lines, Inc. (the Joint Cooperatives) on May 23, 2016 in Proceeding No. 16A-0117E is granted. The Joint Cooperatives are a party in this consolidated matter.

15. The Motion for Leave to Intervene filed by the City of Boulder (Boulder) on May 27, 2016 in Proceeding No. 16A-0117E is granted. Boulder is a party in this consolidated matter.

16. The Motion to Intervene filed by Tri-State Generation and Transmission Association, Inc. (Tri-State) on May 27, 2016 in Proceeding No. 16A-0117E is granted. Tri-State is a party in this consolidated matter.

17. The Petition to Intervene filed by Climax Molybdenum Company (Climax) and CF&I Steel L.P. (CF&I) on May 31, 2016 in Proceeding No. 16A-0117E is granted. Climax and CF&I are parties in this consolidated matter.

18. The Motion to Intervene filed by the Colorado Independent Energy Association (CIEA) on June 1, 2016 in Proceeding No. 16A-0117E is granted. CIEA is a party in this consolidated matter.

19. The Motion to Intervene filed by Wells Trucking, Wells Ranch, Westlake Wine and Spirits, Auto Collision Specialists, Leanin' Tree Cards, 88 Drive in Theater, Independence Real Estate Network, Kelsey Alexander, Lou Schroeder, Peg Brady, and Mary Dabman (Ratepayer Coalition) on June 1, 2016, as amended on June 6, 2016 to include the Independence Institute and to remove Peg Brady, is granted, consistent with the discussion above. The Ratepayer Coalition is a party in this consolidated matter.

20. The Motion to Intervene filed by the City and County of Denver (Denver) on June 1, 2016 in Proceeding No. 16A-0117E is granted. Denver is a party in this consolidated matter.

21. The Petition for Leave to Intervene filed jointly by the Rocky Mountain Environmental Labor Coalition (RMELC) and Colorado Building and Construction Trades Council, and ALF-CIO (CBCTC) on June 1, 2016 in Proceeding No. 16A-0117E is granted. RMELC and CBCTC are parties in this consolidated matter.

22. The Motion to Intervene filed by Sustainable Power Group, Inc. (Sustainable Power) on June 1, 2016, in Proceeding No. 16A-0117E is granted, consistent with the discussion above. Sustainable Power is a party in this consolidated matter.

23. The Petition for Leave to Intervene filed by Southwest Generation Operating Company, LLC (SWGen) on June 1, 2016 in Proceeding No. 16A-0117E is granted. SWGen is a party in this consolidated matter.

24. The Petition for Leave to Intervene filed by Western Resource Advocates (WRA) on June 1, 2016 in Proceeding No. 16A-0117E is granted. WRA is a party in this consolidated matter.

25. The Petition to Participate as *Amicus Curiae* filed by Invenergy Wind Development North America LLC (Invenergy) on June 1, 2016 in Proceeding No. 16A-0117E is granted. Invenergy may participate as *amicus curiae* in the consolidated cases.

26. The Motions to Adopt Procedural Schedule, to Expedite Review of the Application, and Requesting Waivers filed by Public Service on May 13, 2016 in Proceeding No. 16A-0117E are granted, with modifications, consistent with the discussion above.

27. Answer Testimony shall be filed no later than July 27, 2016.

28. Rebuttal Testimony and Cross-Answer Testimony shall be filed no later than August 22, 2016.

29. All prehearing motions, including, but not limited to, dispositive motions, motions to strike testimony, and motions to approve stipulations and settlement agreements, shall be filed no later than August 29, 2016.

30. Responses to prehearing motions shall be filed no later than September 1, 2016, consistent with the discussion above.

31. A prehearing conference is scheduled in this matter as follows:

DATE: September 2, 2016

TIME: 10:00 a.m. to 12:00 p.m.

PLACE: Hearing Room
Colorado Public Utilities Commission
1560 Broadway, Suite 250
Denver, Colorado

32. Hearings in this matter shall be scheduled on September 7 through 9, 2016, consistent with Decision No. C16-0423-I, issued May 19, 2016 in Proceeding No. 16A-0117E.

33. Final post-hearing statements of position shall be filed no later than September 19, 2016.

34. Discovery shall commence for all parties no later than the effective date of this Decision. Discovery shall be conducted in accordance with 4 *Code of Colorado Regulations* (CCR) 723-1-1405 unless modified by this Decision, consistent with the discussion above. Responses to discovery directed at the Application and Direct Testimony shall be provided within seven days. Responses to discovery directed at Answer Testimony shall be provided within five days. Responses to discovery directed at Rebuttal Testimony and Cross-Answer Testimony shall be provided within three days. The cutoff date for discovery service shall be August 29, 2016, and responses to all outstanding discovery requests shall be provided no later September 1, 2016.

35. Consistent with the discussion above, responses from an intervening party to any motion to compel directed at the intervening party shall be filed within five business days. Responses from Public Service to any motion to compel directed at Public Service shall be filed within three business days.

36. Public Service shall file an amended application and amended Direct Testimony to remove its request for the Commission to establish a baseline and methodology to determine the potential level of net economic benefits for a potential future request under 4 CCR 723-3-3660(g), consistent with the discussion above. The amended application and revised testimony shall be filed no later than 21 days following the effective date of this Decision.

37. The Motion for Protective Order filed by Public Service on May 13, 2016 in Proceeding No. 16A-0117E is granted, in part, consistent with the discussion above. Public Service shall file a modified Non-Disclosure Agreement consistent with this Decision no later than five days following the effective date of this Decision.

38. The Motion for Leave to Reply to Response Pleadings of WRA and Staff filed by Public Service on June 8, 2016 in Proceeding No. 16A-0117E is granted.

39. Notwithstanding the adoption of a procedural schedule to allow for the issuance of a final decision in this matter no later than November 10, 2016, the deadline for a Commission decision on the application filed in Proceeding No. 16A-0117E is extended by an additional 90 days pursuant to § 40-6-109.5, C.R.S., to January 4, 2017.

40. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING June 15, 2016.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

JOSHUA B. EPEL

GLENN A. VAAD

FRANCES A. KONCILJA

Commissioners