BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR A POWER PURCHASE AGREEMENT WITH AURORA DISTRIBUTED SOLAR, LLC FOR UP TO 100 MW OF SOLAR GENERATION

Case No. PU-15-________

APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE

I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, respectfully submits this Application to the North Dakota Public Service Commission for an Advance Determination of Prudence (ADP) pursuant to North Dakota Century Code § 49-05-16, for up to 100 MW of nameplate solar generation to be added to the NSP System[1] through a 20-year power purchase agreement (PPA) with Aurora Distributed Solar, LLC, an affiliate of Geronimo Energy, LLC (Geronimo Solar PPA).

The capacity and energy acquired under the Geronimo Solar PPA will be provided by distributed solar generation facilities to be located at up to 24 sites in Minnesota that interconnect to various Xcel Energy distribution substations. This application is made pursuant to N.D.C.C. § 49-05-16, the Settlement Agreement in Case No. PU-07-776, the Company's commitments in Case No. PU-12-59, and the Settlement Agreement in Case No. PU-12-813, *et. al.*

Our proposed resource addition to the NSP System will help (1) meet an identified capacity need of 150-500 MW on our system in the 2017-2019 time period that was identified in our 2010 Resource Plan, and (2) support our long-term solar energy commitments as described in our January 5, 2015 Resource Plan filing in Case No. PU-15-019.[2] To meet the need, we are proposing to add three new resources: (1) the

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[1] The NSP System is comprised of generation, transmission, distribution and associated assets, designed to serve our approximately 1.8 million customers across five states: North Dakota, South Dakota, Minnesota, Wisconsin and Michigan. The Company plans, implements and operates the NSP System on an integrated basis, taking into account the needs of all of our customers and addressing the legal and policy requirements of all of our jurisdictions.

[2] Related filings that ultimately resulted in the resource presented in this application include: filings with the North Dakota Public Service Commission (Case Nos. PU-10-580, PU-13-194, PU-13-195) and Minnesota Public Utilities Commission (MPUC Docket Nos. E002/RP-10-825 and E002/CN-12-1240).

Geronimo Solar PPA, which is the subject of this Application; (2) Black Dog Unit 6, a 215 MW (nameplate) combustion turbine for which we have already received an ADP from the Commission in Case No. PU-13-194; and (3) the output from the 345 MW (nameplate) combined-cycle PPA with Mankato Energy Center, LLC, an affiliate of Calpine Corporation (the Calpine Project PPA).

We have determined that this portfolio of projects is a reasonable and prudent set of resources to meet the capacity need. As the Commission is aware, the Company initially proposed that our need be met with the addition of up to three new 215 MW natural gas combustion turbine units, with one of the combustion turbines (CT) located at our existing Black Dog plant (Black Dog Unit 6), in Burnsville, Minnesota, and the other two CTs (Red River Valley Units 1 and 2) located at a new plant to be constructed near Hankinson, North Dakota, in the Red River Valley.[3] The Commission found these additions to be prudent and an ADP was granted for each of these resources.[4]

We acknowledged in Case No. PU-13-194, however, that it was not certain that the three proposed units reviewed in that Case would actually be constructed as we were also evaluating capacity proposals that were submitted in the Minnesota Public Utilities Commission's (MPUC) Competitive Acquisition Process (CAP) proceedings.[5] In the CAP Docket (which is a mandatory process for Xcel Energy in Minnesota) the Company evaluated: (1) Black Dog Unit 6; (2) the Red River Valley Units; (3) the Calpine Project; (4) the Geronimo Solar Project; (5) a 150 MW combustion turbine project proposed by Invenergy to expand its existing Cannon Falls, Minnesota facility (Invenergy Project); and (6) a system purchase from Great River Energy.

In evaluating these resource options, our analysis showed that Black Dog Unit 6 in conjunction with either the Calpine Project or the Invenergy Project were least-cost

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[3] *In the Matter of the Application of Northern States Power Company for an Advance Determination of Prudence for Three Natural Gas Combustion Turbine Generators*, Case No. PU-13-194 (Gas CT Case), Application for Advance Determination of Prudence (Gas CT ADP) at 1-2.

[4] The Commission granted the ADPs in its February 26, 2014 *Order Adopting Settlement* that resolved issues in a number of matters, including the Gas CT Case.

[5] *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 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, and *In the Matter of Draft Power Purchase Agreements with Calpine Corporation and Invenergy Thermal Development, and Proposed Price Terms for Black Dog Unit 6*, Docket No. E-002/M-14-789, ORDER APPROVING POWER PURCHASE AGREEMENT WITH CALPINE, APPROVING POWER PURCHASE AGREEMENT WITH GERONIMO AND APPROVING PRICE TERMS WITH XCEL, (Feb. 5, 2015)(February 2015 CAP Order). The CAP Docket is discussed in the Gas CT Case, Supplemental Testimony of James R. Alders (Alders Supp. Testimony) (Nov. 12, 2013) at 12.

options to fill the identified capacity need.[6] With respect to our evaluation in the CAP Docket, which utilizes externality values required under Minnesota's resource evaluation process, our analysis demonstrated that the combination of Black Dog Unit 6 with the Calpine Project PPA, or the combination of Black Dog Unit 6 with the Invenergy Project PPA had less societal costs.[7] However, evaluation of other resource options presented in the CAP Docket suggested other benefits could be derived with a larger resource portfolio consisting of the Geronimo Solar PPA in addition to Black Dog Unit 6 and the Calpine Project PPA.

Ultimately, we concluded that the Geronimo Solar PPA is a prudent resource to add capacity to the system and to further our renewable energy goals and obligations. It also provides fuel diversity and added flexibility to further reduce CO_2 and fossil-fuel emissions. When paired with the other resources we have selected – Black Dog Unit 6 and the Calpine Project PPA – the Geronimo Solar PPA provides additional diversity of resources on our system to meet our customers' needs at an overall reasonable cost.

Purchasing this solar capacity at this time provides several strategic benefits, including:

- Adding new capacity on the system at this time enhances flexibility for future decisions relating to potential retirements of older existing thermal resources on our system. This timing provides benefits by maximizing flexibility depending upon future circumstances.
- Adding carbon-free solar generation at this time provides a hedge against future natural gas price volatility and emerging environmental regulations that, if enacted, would make it increasingly likely that the Company's older coal resources may need to be replaced.
- Adding solar generation at this time allows the project to capture the benefit of a 30 percent investment tax credit (ITC) that is set to step down to 10 percent at the end of 2016.

The Company recognizes that this ADP is for a resource that is not least-cost on a Present Value of Revenue Requirements (PVRR) basis. We also recognize that this resource was chosen, in part, as a result of Minnesota's resource selection process that included consideration of that State's energy policies. This Application and supporting testimony will demonstrate the prudence of this resource addition under the present circumstances within the Company's integrated NSP System.

[6] Case CT Case, Alders Supp. Testimony at 10-11.
[7] Case CT Case, Alders Supp. Testimony at 23, and Table 5 at 26.

In support of this Application, the Company provides the Direct Testimony of Company Witnesses Ms. Laura McCarten, Mr. Paul B. Johnson, and Mr. Kurtis J. Haeger. Ms. McCarten's Direct Testimony provides additional information with respect to the CAP process, the selected resource, and the benefits of adding capacity at this time. Ms. McCarten also describes the issues raised in the Company's last rate case regarding the divergent energy policies among some of the states in which the Company provides electric service. Mr. Johnson provides information regarding the Strategist modeling supporting this filing. Mr. Haeger discusses the factors that affect the Company's forecasting of its need, as well as the considerations that impacted the Company's determination that the Calpine Project PPA, as well as the Geronimo Solar PPA and Black Dog Unit 6, are the appropriate resources to add to our system in light of the Company's down-stream capacity needs. Mr. Haeger also discusses the "Restack concept" embodied in our recent rate case Settlement Agreement, and how the Restack could be utilized in this proceeding.

The remainder of this Application will provide:

- Description of the Applicant;
- Communications and Service;
- Standard of Review;
- Determination of Need;
- Resource Selection Processes;
- Geronimo Solar PPA;
- Prudence of Geronimo Solar PPA; and
- Conclusion.

II. DESCRIPTION OF APPLICANT

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

Northern States Power (NSP) Company,
a Minnesota corporation
414 Nicollet Mall
Minneapolis, Minnesota 55401

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

Northern States Power (NSP) Company,
a Minnesota corporation
2302 Great Northern Drive
Fargo, North Dakota 58102

The Company's Certificate of Incorporation with amendments and Certificate of Authority were filed with the Commission on September 30, 2009 and October 12, 2009, respectively, in Case No. PU-09-664. Current Certificates of Good Standing issued by the North Dakota and Minnesota Secretaries of State were filed in the same docket on January 13, 2014, and are incorporated herein by reference.

Xcel Energy has service territory in five upper Midwest states including North Dakota. We presently serve over 112,000 retail electric customers in and around Fargo, Grand Forks, and Minot, North Dakota. We own approximately 304 miles of transmission lines and 19 substations in North Dakota.

III. COMMUNICATIONS AND SERVICE

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

David H. Sederquist	Tiffany Hughes
Senior Consultant, Regulation and Finance	Records Specialist
Xcel Energy Services Inc.	Xcel Energy Services Inc.
2302 Great Northern Drive	414 Nicollet Mall, 7th Floor
Fargo, ND 58102	Minneapolis, MN 55401

IV. STANDARD OF REVIEW

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

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

N.D.C.C. § 49-05-16 (1), the Commission may issue an order approving the prudence of a proposed project if four conditions are met:

1. The public utility files with its application a projection of costs to the date of the anticipated commercial operation of the resource addition;
2. The public utility files with its application a fee in the amount of one hundred seventy-five thousand dollars;
3. The commission provides notice and holds a hearing, if appropriate, in accordance with section 49-02-02; and
4. The commission determine that the resource addition is prudent. For facilities located or to be located in this state the commission, in determining whether the resource addition is prudent, shall consider the benefits of having the resource addition located in this state.

V. DETERMINATION OF NEED

A. Forecasting Need

The assessment of whether there is a resource need is based on three primary factors: the Company's peak demand forecast; its reserve margins; and the maximum generation capability of its existing resources. In addition, in assessing need, the Company must look to the energy policies of its various jurisdictions and assess whether certain types of generation are needed to satisfy the legal and policy requirements in one or more of our jurisdictions. For example, the Company may need additional capacity of a particular type to meet relevant requirements, such as additional renewable energy to reduce green house gas and fossil fuel emissions to meet evolving federal and state limitations. In other words, we determine the need to add generation to our system based on a variety of requirements, including the requirement that we at all times (1) meet our customers' demand for electricity (peak demand); (2) ensure an adequate margin of excess capacity to reliably do so (reserve margins); and (3) have adequate capacity from the resources we have available to meet customer demand while maintaining our reserve margin.

In addition to analyzing peak demand in our forecasts, we also forecast our total annual energy requirements (sales plus transmission losses), including the impacts of Demand-Side Management. By doing so, we can assess not only our capacity needs but also the type of resource that will best address our energy needs. This analysis is necessary to determine if a baseload, intermediate, or peaking resource addition will be the most appropriate type of resource to add to the system to address energy as well as capacity needs.

As part of our resource planning efforts, we develop forecasts of these variables to determine if there is a need to add more resources to our system in the future as well as what types of resources to add. As time goes on, forecasts can and do change and changing economic conditions impact the level and timing of the need. Accordingly, it is important to recognize that forecasts are essentially predictions of potential future circumstances based on a specific set of assumptions at a particular point in time.

Building electric generation is an expensive and time-consuming endeavor that must be planned well in advance in order to complete construction to match the anticipated need. Consequently, we must rely on our forecasts to determine if we have a need to add capacity to our system, recognizing that our forecasts may change over the long lead times inherent in generation development. To avoid the "analysis paralysis" that can be inherent in trying to forecast an uncertain and ever-changing future, we must at some point establish a need and then begin the long-lead-time process of selecting resources, obtaining regulatory approvals, permitting, developing, and constructing the generation resources.

In general, we first determine if there is a system capacity need as part of the forecasting process utilized in our resource planning efforts. We then update that forecast to provide the best available information to our regulators as we begin the process to obtain regulatory input regarding which resources to select to meet that need. These forecasts, taken together, form the basis for our subsequent decisions on how to proceed rather than become stuck due to the "analysis paralysis" described above. As regulatory processes are ongoing, we may update our forecasts several times to determine if our initial analyses continue to demonstrate the appropriateness to add resources to our system based on the updated information.

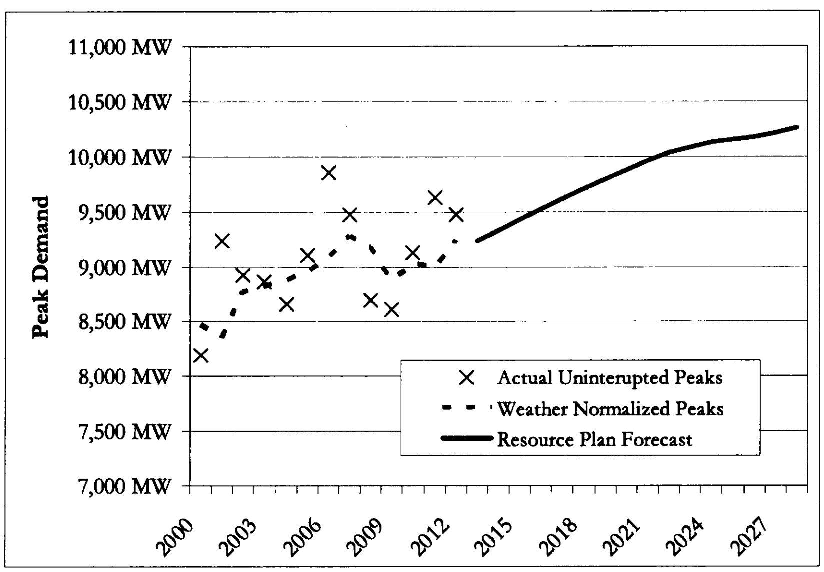
1. Fall 2011 Forecast

In this Case, the forecast used to establish the capacity need of 150-500 MW was the Company's updated Fall 2011 Forecast. The Fall 2011 Forecast updated the forecasting analysis in our 2010 Resource Plan, which first identified our capacity need. Mr. Haeger further describes in his Direct Testimony the forecast needs identified in our 2010 Resource Plan proceedings, the updates we made to that forecast, and the effects of the economic circumstances in that timeframe on our forecast.

The Fall 2011 Forecast (augmented with information through our Spring 2013 forecast) was the most up-to-date information available when the Company began the regulatory approval processes in North Dakota and Minnesota for the selection of appropriate resources to meet the identified need. This is the forecast underlying our analysis in the Gas CT Case, as well as the resource selection proceedings in the MPUC's CAP Docket, and we advised that it was prudent to plan to meet the identified need in the Fall 2011 Forecast because "this ensures adequate generating capacity under all reasonable circumstances."[8] While subsequent forecasts have indicated a lower need in 2017-2019, we concluded it was appropriate to rely upon the Fall 2011 Forecast in our analysis and subsequent applications to provide consistency through the many reviews of our resource selections.

Figure 1 provides the Fall 2011 Forecast's peak demands. As shown in Figure 1, from 2013 through 2020, the average rate of growth in our peak demand forecast is 1.0 percent.

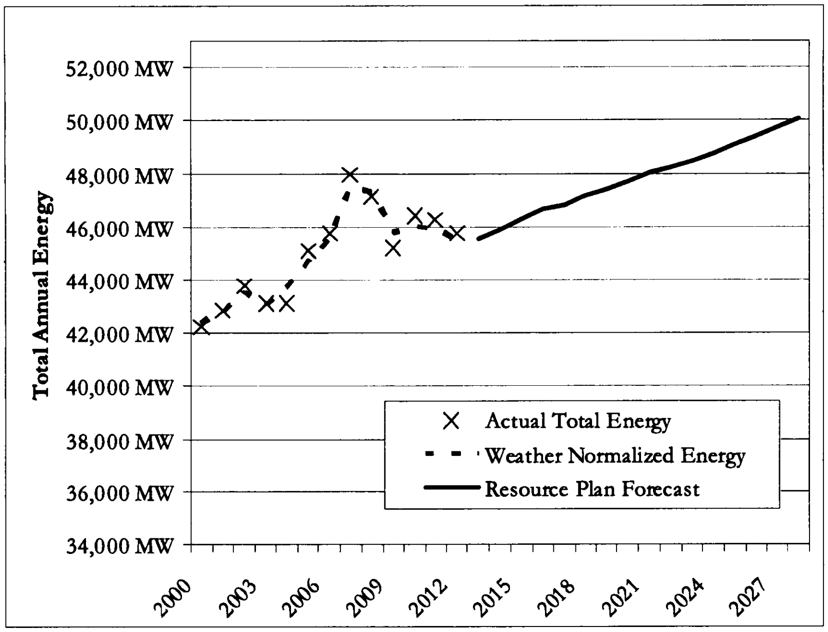
Figure 1:
NSP Historic and Forecasted Peak Demand



Our total annual energy forecast is shown in Figure 2. The Fall 2011 Forecast assumed an average growth rate from 2013 to 2020 of 0.7 percent.

[8] Gas CT ADP at 18.

Figure 2:
NSP Historic and Forecasts Total Annual Energy



Our Fall 2011 Forecast also took into consideration the reserve margin calculations specified by Midcontinent Independent System Operator, Inc., (MISO) using the criteria applicable at the time. 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 10 years. Comparing the load forecast plus reserve margin to the capacity ratings of Xcel Energy-owned resources plus purchased power, our system's forecasted capacity need is approximately 500 MW by 2019-2020 as shown in Table 1.

Table 1:
System Capacity Need
(Fall 2011 Forecast)

	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

Our Fall 2011 Forecast identified a capacity need of 154 MW in 2017, growing to 532 MW in 2020.

2. Subsequent Forecast Updates

Since developing our Fall 2011 Forecast, we have updated our demand forecast several times: in the Spring of 2012, in the Fall of 2012, in the Spring of 2013, and in 2014 as depicted in Figure 3 below. As described in Mr. Haeger's Direct Testimony, this is a normal part of planning, but as a result, it is necessary to decide which forecast is the most prudent to use to make a resource addition to avoid the risk that "analysis paralysis" prevents the Company from timely meeting need as it materializes.

Most recently, the Company prepared a new forecast to support our recently-filed 2015 Resource Plan.[9] The most recent forecast suggests weakening demand and the possibility that the Company will not need to add additional capacity to its system until approximately 2024. This suggests the Company could delay adding resources to its system at this time. However, in light of the various reviews and applications of

[9] Case No. PU-15-019.

our Fall 2011 Forecast with respect to resource options and related timing, we are not relying on the forecast in the 2015 Resource Plan filing to support the need in this Case.

B. Forecast Uncertainty

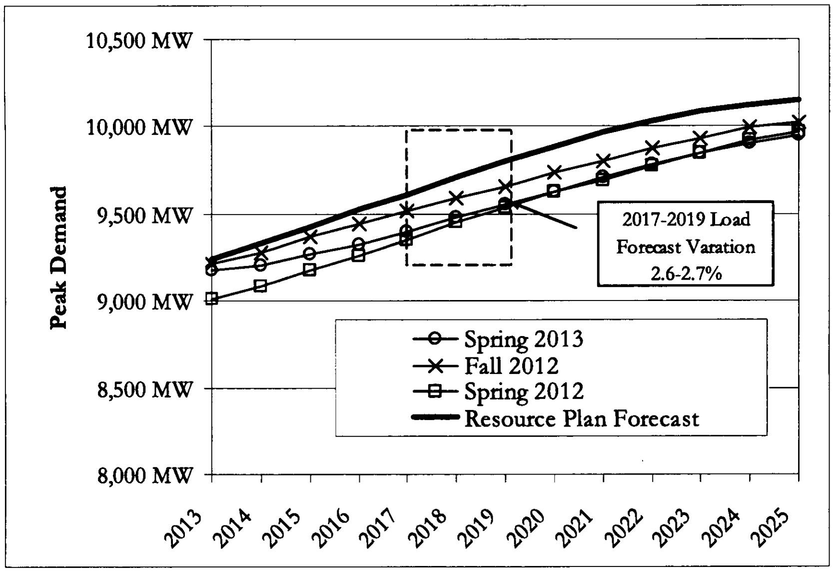
As described in greater detail in Mr. Haeger's Direct Testimony, peak demand forecasts are dependent on underlying assumptions regarding economic growth. If the assumptions change, the forecast will change. And if actual circumstances do not match the assumptions used, actual results will be different than the forecast results.

These assumptions can change dramatically with the ups and downs of the economy. For example, it has been difficult to predict what kind of economic conditions will result from the uneven recovery across the region from the 2008 recession. And it continues to be difficult to predict what impact current circumstances, such as the recent drop in oil prices, may have on our load growth. The Company's varying forecasts over the course of its resource planning process supports taking a conservative approach to ensure sufficient available generation to serve our customers' requirements under all reasonable circumstances.

Relatively small changes in economic growth rate assumptions can have a significant impact on the amount of needed resources. With a nearly 10,000 MW integrated system, a demand forecast change of only a few percent result in estimates varying by several hundred MWs. The variation in our load forecast occurs within a relatively tight range, however, and the amount of the variation is relatively small in the context of our total system peak demand.

As noted above, since the Fall of 2011 when our 2010 Resource Plan analysis was completed, the Company has updated its forecast several times. The total variation in forecasts has been about 250 MW, or 2.6 percent, in the 2017–2019 timeframe. Figure 3 shows the peak demand forecast changes.

Figure 3:
Variation in Peak Demand Forecasts



These relatively small variations in our forecasts 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.

Figure 4 below, which includes a series of recent demand forecasts arising during our 2010 Resource Plan proceedings, illustrates the forecasting uncertainty and the potential that very small changes could result in a material swing in the required amount of capacity.

Figure 4:
Impact of Coincident and Non-Coincident Peak Methodologies on Resource Plan Need Forecasts

Source: Department of Commerce, Docket No. E002/CN-12-1240 (December 10, 2014)

C. Implications of Forecast Variability

Xcel Energy generally takes a conservative approach to evaluating resource needs to ensure the Company has adequate resources to satisfy our obligation to serve under all reasonable circumstances. Forecast demand fluctuates over time, and sometimes significantly, based on small changes in economic indicators. Because resource decisions are made in the midst of this type of fluctuation, we must balance the cost of new generation against the risk of falling short or exposing our customers to too much market risk. In reaching that balance, we believe it is appropriate to plan for a range of 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.

The variability in our forecasts since the Fall 2011 Forecast, which established our baseline resource need, indicates that the NSP System could be in deficit between 2017 and 2024. Even our current forecast (used in the 2015 Resource Plan) shows that our capacity position in 2019 and 2020 is very near a deficit and any uptick in demand would put us in the position of needing to acquire market capacity. In addition, this variability is impacted by the public policy choices that we are called upon to implement within our integrated NSP System.

The variability in our forecasts also indicates some uncertainty with respect to the size and timing of our capacity need. Consequently, the question is not if but when to make resource additions, and of what size and type. Answering these questions must also take into account known changes to our system in the out-years of our planning horizon to ensure we have sufficient capacity to address retiring generation, expiring PPAs, and other known issues that will affect our generation fleet.

While delaying making any resource decision until the actual timing and size of a capacity need is certain would limit the rate impacts of adding resources to our system, the drawback of this course of action is that it could require us to make the ultimate decision to add resources very near to the time they are needed. This would limit the opportunity to examine different options, since the urgency to meet an imminent capacity deficit will likely outweigh cost considerations in deciding which resource to select. Thus, we would likely be price takers in the marketplace as a result of the decision to add resources being made close to the timing of the need. Delaying a decision for more certainty may put us in a position where we cannot construct the needed resources in time to meet the need. This could lead to us being short on capacity and subject us to uncertain and volatile short term capacity market prices to obtain the significant amounts of capacity necessary to meet the needs of the large, integrated, NSP System.

Another course of action is to act conservatively in the face of uncertainty and make resource additions as a need is forecasted and have those additions be of a size and type to address the need in a way that also positions us well for the future. This approach is premised on the assumption that it is better for a utility to be long than short on capacity, since the utility has the obligation to serve all of its customers' needs under all reasonable circumstances and must have resources available to meet those needs. The benefits to this approach are that it provides the time needed to make resource decisions through the use of competitive processes to help bring down the cost of these resources. Additionally, it avoids exposing the Company - and ultimately customers - to short-term capacity markets and the price uncertainty inherent with such markets. The drawbacks to this approach are that it could lead to a system that is overbuilt in the short term, with the consonant cost impacts to customers.

We recognize that these two paths sit on opposite ends of the resource planning spectrum and that the most prudent approach to adding capacity to the NSP System lies somewhere in the middle. Mr. Haeger provides additional discussion in his Direct

Testimony with respect to balancing uncertainty and reliability. This ADP Application presents the difficult question of where along this spectrum is the appropriate point at which to make a resource decision. We believe our Application demonstrates the prudence of making resource additions now in spite of forecast uncertainty, which includes a recent forecast update that shows a slacking of demand.

VI. RESOURCE SELECTION PROCESS

Xcel Energy recognizes that that the Geronimo Solar PPA was selected in the Minnesota CAP Docket and that its selection is, in part, an outcome of energy policies in Minnesota. To put this ADP request in context, we begin with a description of the processes we undertook to select this resource.

A. Overview

The Company, along with its affiliate Northern States Power Company, a Wisconsin corporation, jointly plan for and operate the integrated NSP System. The NSP System serves over 1.8 million retail electric customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. Because customers in these five states are served by the same system, we have been able to achieve significant economies of scale that provide benefits to all of our customers in all of the states we serve.[10] We have been successfully planning for and managing the integrated NSP System to meet all of our customers' needs for almost 100 years.

The operation of the NSP System is subject to the regulatory oversight of five State utility commissions, as well as various stakeholders within each State. Each of the States in which we provide electric service has different regulatory constructs and oversight regimes. Two of the States in which we provide service – North Dakota and Minnesota – require a form of preapproval for the resources we select. The other states we serve generally determine the prudence of a resource addition when we seek to include those costs in rates through a rate case.[11]

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[10] Our integrated system provides significant benefits to our customers and offers economies of scale benefits that could not be available from a smaller or single-jurisdiction utility. Our customers benefit from a *pro rata* share of our almost 1,800 MW of nuclear generation and associated carbon-free energy, over 3,000 MW of coal generation and 900 MW of advantageous Canadian hydro capacity and carbon-free energy.

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

We are required to balance the energy policies of all of the States in which we provide service. The Company appreciates the input and feedback from all of our regulators on appropriate resource choices and that we are constrained to follow the regulatory processes prescribed by lawmakers and regulators in each State.

In making resource choices we take into account existing and evolving environmental regulations; State public policy choices from each of our jurisdictions; changing customer expectations; the condition of our existing generation fleet, which is aging and will require significant change in the coming years; and emerging technologies that change the way energy is generated and delivered. This multifaceted set of issues sometimes means that we may choose a resource to meet state policy goals in an amount greater than what our forecast might suggest, particularly in a circumstance where we have experienced forecast volatility.

We have provided a robust discussion of all of these competing interests in our recent 2015 Resource Plan filing. However, we provide additional discussion of some of these critical issues here as they had an impact on our decision to seek an ADP for the Geronimo Solar PPA.

1. Evolving Environmental Regulations

New air, water, and waste regulations have been updated and adopted by the Environmental Protection Agency (EPA). Regulations for criteria pollutants - particularly oxides of nitrogen, sulfur dioxide, particulate matter, and ozone - continue to be updated and are likely to impose added constraints on operation of some power plants. The EPA has proposed its existing source Clean Power Plan, and has announced that it anticipates finalizing these new rules in mid-summer 2015. Further, Regional Haze Rules and other environmental regulations will also impact our generation fleet. Maintaining flexibility to comply with these requirements will be important over the coming years. These regulations inform our thinking as to (1) what will be necessary to maintain compliance at our generating facilities, and (2) what type of resource additions we may need in the future.

With that said, uncertainty surrounds some of the EPA's environmental regulations. The primary example is the EPA's existing source greenhouse gas (GHG) performance standard, known as the Clean Power Plan, or Section 111(d). The EPA has issued proposed rules, which are expected to be finalized in June 2015. The proposed 111(d) process will determine what compliance alternatives are available, whether each of our jurisdictions will implement unit-based or mass-based programs, whether they will collaborate with other states in multi-state plans, and how much of the CO_2 reduction burden they will assign to the Company versus other utilities. We will not definitively know our share of the responsibility for meeting the attainment requirements in any of the states we serve, or our compliance options, until the states submit and EPA approves a state implementation plan (SIP).

Any final rule is likely to face legal challenges, which depending on whether or not the rule is stayed during litigation, may affect the timeline for SIP development. If the rule is not stayed, each State will draft plans and submit them to the EPA by the 2016 to 2018 timeframe, for approval one year later with compliance beginning in 2020. If the rule is stayed, it is unknown what the compliance obligations will be or when compliance obligations will begin.

The uncertainties surrounding these new and emerging regulations suggest that it is reasonable for us to hedge our system-wide portfolio now to provide multiple ways to ensure compliance with final regulations as they emerge.

2. Evolving NSP System

As we describe more fully in our 2015 Resource Plan, our integrated NSP System is evolving and may change significantly over the next 20 years. From 2025-2035, we will experience a reduction in energy resources due to power contracts expiring, plant retirements, and the expiration of our nuclear licenses. Fully 75 percent of our supply portfolio will need to be addressed by 2035.

First, the future of Sherco Units 1 and 2 is of considerable importance to the Company and our stakeholders. We anticipate that without the installation of costly Selective Catalytic Reduction (SCR) equipment, these units could not operate beyond 2030 under anticipated environmental requirements. As described in more detail in our 2015 Resource Plan, some of our stakeholders would prefer that these units be retired earlier while others may desire that the needed investments be made to preserve the potential for extended operations.

No decision on the future of Sherco Units 1 and 2 has been made. Indeed, we anticipate the future resolution of Sherco Units 1 and 2 will result in a significant policy debate among all of our stakeholders. Nevertheless, it will be important for the Company to have options in place to address the eventual outcome of that debate. Adding carbon-free generation to the system now provides flexibility as the policy debates on our supply mix play out.

Second, in 2023 we are planning to cease operation of the 153 MW Blue Lake Units 1-4 as these older oil-fired peaking units reach the end of their useful life. In 2025, our 825 MW Manitoba Hydro contracts expire. In 2026 and 2027, our contracts for the output of the 262 MW Cottage Grove Combined Cycle Energy Center and existing 375 MW Combined Cycle unit at the Mankato Combined Cycle Energy Center expire. This is generation that will need to be replaced and having supply choices available to us provides additional flexibility in designing the optimal future supply mix.

Third, in 2030 our license to operate our 671 MW Monticello nuclear plant expires, and in 2033/34 our licenses for our 1,100 MW Prairie Island nuclear plant expires. At this time we only have authority to operate these units to the end of their existing licenses. Since nuclear is a crucial carbon-free, baseload resource, federal and state carbon goals will become more difficult to meet when these nuclear plants retire.

The potential turnover of all of this generation during the next 20 years (whether or not Sherco Units 1 and 2 are retired), suggests that a significant proportion of our baseload and intermediate generation resources may be in flux. It will be important for the Company to maintain plans to meet the capacity and energy needs of all of our customers while retaining flexibility and avoiding over-reliance on any one fuel source, specifically natural gas, given that most proposed thermal generation additions are fueled by natural gas.

3. Balancing State Energy Policies

One of the consequences of planning and running the system on an integrated basis is that we are required to address the energy policies of all of the states in which we serve. Sometimes this requires us to balance conflicting policy goals. While some states within our integrated system, such as Minnesota, have been active in pursuing state-specific energy-policy goals, other states, such as North Dakota, have chosen not to regulate as actively and have focused more on cost-of-service goals. In the last five years it has become increasingly challenging for the Company to maintain a workable balance as the energy policies of some of the states we serve diverge.

One important balance that has been increasingly prominent over the past few years is the balance between environmental policy goals on the one hand and least-cost planning principles on the other. For example, the Company has been a leader in advancing renewable energy in the upper Midwest and, for the most part, has been able to do so at reasonable costs. However, some of the requirements and targets imposed in Minnesota are higher than comparable requirements and targets in North Dakota, where the focus is more on least-cost resource planning principles. This dynamic creates both opportunities and challenges as we try to plan for an integrated system that meets the requirements of all of our customers.

B. Applicable Preapproval Processes

We provide a brief description of the relevant pre-approval processes that resulted in this Application. Ms. McCarten provides further discussion of these processes in her Direct Testimony.

1. North Dakota ADP Process

In North Dakota, when the Company seeks to acquire a resource for our system it will file an ADP Application to obtain the Commission's approval before the acquisition is made.[12]

In the Settlement Agreement of our 2007 North Dakota rate case,[13] the Company agreed to a series of process changes that, among other things, require Xcel Energy to apply for an ADP from the Commission for any resource addition to the NSP System of 50 MW and larger. Prior to this time, the Company had no obligation in North Dakota to seek pre-approval of its resource additions. And, before the ADP process became law, the prudence of the Company's resource additions was subject to an after-the-fact prudence review in a rate case or a Fuel Cost Recovery (FCR) proceeding.

Our ADP filing obligation for larger additions was further refined in Case No. PU-12-59 to address Commission concerns about the timing of ADP filings. In that case we committed to coordinating our ADP applications with the timing of the Minnesota process. In Case No. PU-12-813, our most recent rate case, we again refined our ADP obligations through a settlement that provides that the Company may not recover the costs of any PPAs through the FCR rider without an ADP being granted by the Commission for any resource addition over 50 MW.[14]

Taken together, the Company views these obligations as creating a required resource pre-approval process in North Dakota that (1) defines the timing requirements for filing for Commission approval, and (2) results in a Commission prudence determination that is binding for the resource as if it were reviewed in a rate case.

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[12] In her Direct Testimony accompanying this ADP application, Ms. McCarten discusses in more detail the history of the Company's obligations and practices with respect to seeking Commission approval for the addition of resources to the NSP System.

[13] Case No. PU-07-776.

[14] The Company notes that the Geronimo Solar PPA is structured in such a way that the Company makes a bundled capacity and energy payment. This bundled payment would be included in our FCR calculations.

2. Minnesota

In Minnesota, resource acquisitions are reviewed in a two-step process. First, resource needs are determined through Minnesota's resource planning proceedings before the MPUC.[15] Second, the Company undergoes a MPUC designed acquisition process to obtain approval of adding the resource to meet the need.

Pursuant to Minn. Stat. § 216B.2422, subd. 5, the MPUC is empowered to establish a competitive bidding process under which a utility acquires a resource to meet a need identified in the 2010 Resource Plan process. Xcel Energy is subject to the MPUC's competitive process.[16] The competitive bidding process that the MPUC has established for Xcel Energy is composed of two separate methodologies: "Track 1" and "Track 2."

The "Track 1" process is used in the circumstance where Xcel Energy is not seeking to construct the resource itself. That process provides that we use a competitive Request for Proposals (RFP) process. This is intended to ensure that the Company probes the market for the most cost-effective and appropriate proposals available. Since its implementation, the Track 1 process has been the primary method we have used to procure new resources, and we have entered into numerous PPAs with third-party vendors for generation selected through RFPs.

The "Track 2" process applies when the Company seeks to meet its identified resource need with a Company-owned, self-build project. The Track 2 process involves soliciting and evaluating alternative competitive proposals to the resource proposed by the Company. This is intended to ensure that the Company probes the market for resource proposals from independent power producers that may be more cost effective than the Company's self-build proposal.[17]

The Track 2 CAP consists of the following steps:

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[15] Minn. Stat. § 216B.2422. Resource review in South Dakota is handled through a prudence review when the utility files a rate case that proposes adding the resource to rate base.

[16] *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) (2006 CAP Order).

[17] While the Track 2 process for a self-build resource proposal by the Company has been in place since the Commission's 2006 CAP Order, the process has not been used prior to the current CAP Docket. The Company therefore had no previous experience with the complexities of selecting a resource pursuant to the Track 2 process before the current CAP docket was initiated by the MPUC.

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

C. Outcomes of the North Dakota and Minnesota Approval Processes

We provide a brief description of the outcomes of the pre-approval processes that resulted in this Application. Mr. Haeger provides a further discussion of the results of the Minnesota process with respect to the Calpine Project PPA, the Geronimo PPA, and Black Dog Unit 6 in his Direct Testimony.

1. North Dakota

In the Gas CT Case, the Company sought an ADP from the Commission for our proposal to meet a capacity need of 150-500 MW by adding Black Dog Unit 6 and Red River Valley Units 1 and 2 to our system. As we described in our in our Gas CT ADP, the Company was simultaneously seeking approval from the MPUC for Black Dog Unit 6 and the Red River Valley Units under the CAP proceedings, which Xcel Energy was required to do under the Minnesota Track 2 process. We made our application at that time consistent with our commitment in Case No. PU-12-59 that we would apply for an ADP from the Commission at the same time we sought approval for a resource from the MPUC.

In the course of the Commission's consideration of whether to grant our ADP request, we explained that whether or when the Black Dog and Red River Valley

Units might be constructed was not clear due to potential fluctuations in forecast demand, and to the Minnesota Track 2 process which might identify other competitive proposals from independent power producers as more appropriate than our proposed units.

After discovery and a hearing before the Commission, a settlement was reached between the Company and Advocacy Staff that the Commission adopted. The settlement summarizes the substantive and procedural factors that led to the Commission granting ADPs for Black Dog Unit 6 and the Red River Valley Units:

> As part of the Gas CT Cases, the Company proposed to construct two gas combustion turbines (CT) near Hankinson, North Dakota known as Red River Valley Unit 1 and Red River Valley Unit 2 to meet an identified capacity resource need in the 2017-2019 time frame. <u>The record in the Gas CT Cases also reflects the fact that the Company may choose some alternative resource to meet that need instead of one or both of the proposed North Dakota based CTs.</u> In light of the record in the Gas Cases, the Parties acknowledge that the Gas Cases identified the interest of the Commission in ensuring that the Company develops generation closer to its loads in North Dakota. The Parties further acknowledge that the record in the Gas CT Cases reflects the fact that diversifying the location of the Company's generation mix and locating generation closer to the Company's North Dakota loads provides some benefits to the Company's North Dakota customers as well as all of the other customers served by the Company.
>
> <u>In recognition of the fact that the Company's proposal to construct and own North Dakota based generation to meet its 2017-2019 resource need may not be implemented, but to obtain the benefits of North Dakota based generation identified in the Gas CT Cases, the Company hereby commits to develop up to 400 MW of thermal generation resources in North Dakota no later than 2036,</u> consistent with the principles of orderly development of resources, the principle of least-cost development as provided in N.D. Admin. Code § 69-09-02-33, and general concepts of prudent resource planning to meet incremental additional resource needs that may arise in that time frame. In furtherance of the foregoing sentence, and not in limitation thereof, development of North Dakota based generation must be cost effective taking into account the benefits of locating generation nearer to North

Dakota loads and the benefits of geographic diversity of generation when compared to other alternatives.[18]

2. Minnesota

The Company's proposal to build Black Dog Unit 6 and the Red River Valley Units to meet its capacity need triggered the Track 2 process used in the MPUC's CAP docket. Proposals from Calpine , Invenergy, Geronimo Energy, and Great River Energy were also submitted in the CAP docket to compete with the Company's Gas CT proposals.

The MPUC selected three capacity resources to meet the up to 500 MW of capacity need identified in our Fall 2011 Forecast:

Resource (Nameplate)	**Accredited Capacity**	**In-Service Date**	**Technology**
Geronimo Solar Project (up to 100 MW)	Up to 71 MW	2016	Distributed Solar
Calpine Project (345 MW)	278 MW	2018 or 2019	Combined-Cycle Thermal
Black Dog Unit 6 (215 MW)	207 MW	2019	Combustion Turbine Thermal

In its May 23, 2014 Order explaining its resource selections, the MPUC focused on the importance of ensuring that adequate capacity is in place for the Company to meet all of its customers' requirements. Recognizing that the record contained a variety of forecasts and predictions of evolving MISO capacity requirements the Company must meet, the MPUC concluded that the resulting uncertainty warranted selecting resources that delivered enough capacity to avoid a potential shortfall in its ability to meet customer demand. The MPUC determined in these circumstances it was most appropriate to rely upon the Fall 2011 Forecast that had been fully analyzed in the resource planning proceeding, which showed the Company needed up to 500 MW of new capacity by 2019.[19]

The MPUC found that Geronimo's distributed solar generation proposal not only met a portion of the Company's capacity need, but had the added benefit of promoting

[18] Revised Second Amended Comprehensive Settlement, Section II.B (pages 17-18, emphasis added), which is attached to the Commission's Order Adopting Settlement granting the ADPs sought in the Gas CT Case.

[19] The MPUC also noted that various laws and policies that influence resource planning further supported its finding that we should add generation to our system in the 2017-19 timeframe. These policies include state and federal environmental requirements, Minnesota's solar and wind energy requirements, and MISO's reserve margin requirements.

beneficial environmental and socioeconomic policies set forth in state statute. The Commission also concluded that the record demonstrated that Black Dog Unit 6, Calpine proposed combined cycle unit, and Invenergy's proposed combustion turbine unit had comparable merits, and that one or more of these three gas units was needed to meet the Company's capacity need. The MPUC ordered the Company to refine its estimate of the costs for Black Dog Unit 6, and negotiate PPAs for both the Calpine and Invenergy projects, so that the Commission could then determine which of these resources should be selected to meet the Company's need. Based on its review of the PPAs the Company negotiated with Calpine and Invenergy, the MPUC selected Black Dog Unit 6 and the Calpine Project PPA to meet our need.

In its February 5, 2015 CAP Order, the MPUC reaffirmed these selections and ordered Xcel Energy to execute the Geronimo Solar PPA. It also approved the Calpine Project PPA that is being considered in a separate Case.

D. Implications of North Dakota and Minnesota Outcomes

The North Dakota and Minnesota pre-approval processes have resulted in divergent outcomes that require the Company to make difficult choices as to its next steps.

- The North Dakota process resulted in Commission approval of the Company's proposal to add up to three gas CTs (about 625 MW accredited capacity) to our system, with the flexibility to implement that proposal consistent with our need materializing.

- The Minnesota process resulted in the selection of only one of our proposed gas CTs in combination with the Calpine Project's combined-cycle capacity and the Geronimo Solar Project (about 586 MW accredited capacity), which provides different types of benefits to our system given a conservative assessment of our need.

While the two States' processes result in around 600 MW of new capacity, the profile and potential timing of the added generation differs. The benefits of the Geronimo Solar PPA are such that we respectfully request that the Commission conclude that it is a prudent resource selection. The Company believes that adding this resource provides a prudent path forward in light of our need to balance all of the requirements attendant to operating the integrated NSP System. Evolving environmental regulations and our goal to significantly reduce CO_2 and other fossil-fuel emissions suggest that this is an appropriate acquisition at this time.

We recognize, however, that the Commission may disagree with our choice to select a resource addition based primarily on the capacity benefits it provides, as well as compliance with Minnesota energy policies prescribing a certain amount of solar generation. The Commission may determine that the decision to add additional solar to the system at this time is not a choice that comports with its least-cost resource planning approach.

As the Commission knows, the Restack is being developed to address just such a situation. At a high-level, adding a resource to the Restack will ensure that the Company's North Dakota customers pay a reasonable cost for the used and useful capacity and energy of any resource addition that the Company makes. As the Commission is aware, we are currently negotiating a Restack agreement with Staff consistent with the Settlement Agreement in Case No. PU-12-813. Should the Commission not deem the Geronimo Solar PPA prudent, we believe that this resource could be included in that agreement. Of course, the drawback of such an approach is that the Company is unable to recover its full cost of the resource. Mr. Haeger discusses in his Direct Testimony the implications of Commission denial of an ADP for this resource on our Restack efforts.

VII. THE GERONIMO SOLAR PPA

This section provides information on the Geronimo Solar Project and the terms of the PPA with the Company. We provide the Geronimo Solar PPA as Trade Secret Exhibit___(KJH-1), Schedule 2, and discuss its terms below.

A. General Description

The Geronimo Solar PPA has a 20-year term and provides for up to 100 MW of nameplate capacity from distributed solar facilities, ranging in size from 2 MW to 10 MW and located at up to 24 sites in Minnesota. Each of the solar facilities will interconnect to one of the Company's distribution substations, and utilizing excess available transfer capability will inject power into the system at distribution voltage.

The PPA is based upon the Company's Model Solar PPA, which has been used in several of the Company's jurisdictions where we have procured solar energy. This allowed the Company to utilize standardized terms and conditions that it has used with other projects and enhanced certainty and consistency with other contracts.

The pricing structure in the Geronimo Solar PPA provides for a single bundled per MWh capacity/energy price payment structure. This means that all payments are made on a per-MWh basis, and that there is no separate payment for capacity.

Geronimo has contractually committed that the solar generation will achieve approximately 71 percent capacity accreditation through the MISO resource adequacy protocols. This means that if the nameplate capacity of the project is 100 MW, the Company will receive about 71 MW of reliable MISO-accredited capacity. The PPA contains a mechanism to compensate the Company if the capacity level is less than committed in the PPA.

To accommodate Geronimo's tax equity financing of the project, the parties negotiated a single PPA structure covering all sites (each site referred to as a "phase"), with the possibility of the PPA being split into a maximum of three separate PPAs as needed post-COD for tax equity financing purposes. As a result of this structure, each phase is treated as a separate project pre-COD and the Company cannot terminate the single PPA because of any action or inaction of a particular phase that occurs prior to COD. The Company retains, however, pre-COD global default and termination rights for bad acts and defaults by the developer. This structure also provides the developer with flexibility to reduce the aggregate size of the facility if circumstances warrant. The maximum nameplate capacity that may be delivered under the PPA is capped at 100 MW.

In addition to the revenue provided under the PPA, the developer is entitled to a 30 percent ITC for all project phases that achieve commercial operation by the end of 2016. The 30 percent ITC will automatically reduce to 10 percent absent Congressional action for projects in-service beginning in 2017. This means that the decisions necessary for the development and construction of the solar generation to be in service by the end of 2016 are time sensitive.

B. Risk Allocation

The PPA addresses areas of risk in the following ways:

Delay/Termination of PPA. Geronimo's pricing depends in part on its phases qualifying for the ITC. There is no mechanism to increase the price if phases go into service after expiration or reduction of the ITC (currently scheduled to reduce from 30 to 10 percent at the end of 2016). However, the PPA allows Geronimo to stop development of phases and effectively reduce the size of the project if they are unable to complete them in time to qualify for the tax credit..

Transmission Interconnection Costs. None of the Project's phases require interconnection to the transmission grid; they are all connected to the Company's system at the distribution level. Geronimo bears all distribution interconnection costs.

Capacity and Capacity Accreditation Risk. The PPA can be up to 100 MW of nameplate capacity. The PPA includes a scale of damage payments that escalates the further the aggregate MW level of the PPA falls short of the 100 MW. In addition, failure to obtain 71 percent accreditation of the nameplate capacity it delivers results in damages for the period of the accredited capacity shortfall.

Curtailment Costs. The PPA provides a mechanism to determine whether and under what circumstances the facility's output is curtailed. These provisions are similar to what we normally include in our wind and other solar PPAs, modified only to account for the technical differences due to the distributed nature of the solar generation. We note that, unlike wind, solar is an "on-peak" resource and likely will experience fewer curtailments due to negative LMPs or system balancing issues. This is true for both distribution and transmission interconnected resources.

Environmental Risk. The Company will own all environmental and renewable energy credits.

Financial Risk. The Company negotiated pre-COD and post-COD security fund amounts to protect the Company generally from the range of financial risks associated with the Geronimo Solar Project PPA. In addition, Geronimo takes all ITC qualification risks.

Construction/Operational Risk. The Company accepted Geronimo's proposal that completed phases can be recognized as having achieved COD in a 120-day window that begins September 1, 2016 and ends December 31, 2016. For each phase that fails to achieve COD by December 31, 2016, Geronimo will have the option to complete additional project phases but will be required to pay liquidated damages until the phase achieves COD. The PPA also includes protective measures such as specific performance, step-in rights, actual damages, and termination.

Phase-In Approach. As previously discussed, the PPA provides flexibility both as to the timing of completing phases and the ultimate size of the completed project. In order to stage construction and to maximize the potential for project phases to qualify for the ITC, we anticipate that some number of phases may be completed before September 1, 2016, when the PPA authorizes the project to commence commercial operation at the contract price. The PPA provides that the Company will take pre-COD energy produced by a phase before that date. However, the pricing for this pre-COD energy is based on the prevailing market rate. Conversely, as mentioned before, if circumstances warrant, the developer can reduce the aggregate nameplate capacity of the facility by eliminating phases and paying the agreed-upon amount of capacity buy-down payment.

The Company pays the Solar Energy Payment Rate for the output of the project after the Commercial Operation Date. The amounts of that price are set forth in Trade Secret Exhibit___(KJH-1), Schedule 2, Exhibit J, of the PPA, which is attached to Mr. Haeger's Direct Testimony.

C. Conditions Precedent

The Geronimo Solar PPA contains a number of conditions to the parties' performance under the contract. These conditions precedent are important to ensure that the parties appropriately manage their risks under the contract. There are certain risks that are beyond a party's reasonable control and which must be addressed for the project to go forward. Such risks include obtaining required governmental permits and approvals, obtaining required third-party contracts that are necessary for the project to be completed, and obtaining internal approvals of regulatory revisions of the PPA's terms. The PPA provides a mechanism for terminating the PPA if a required condition precedent fails to be obtained.

Geronimo must satisfy two primary conditions in order to be obligated to perform under the PPA. These conditions require obtaining by a specified date: (1) a master site permit for the project or individual site permits for each phase; and (2) satisfactory arrangements for the interconnection of the project phases. In the Company's experience, these conditions and the timelines presented for their completion are typical of the types of conditions we would expect.

The Company has one important condition precedent. Within 10 days after receipt of an order of the MPUC approving the PPA, the Company must request approval of the PPA from this Commission. The MPUC Order approving the Geronimo Solar PPA was issued on February 5, 2015. The present filing was made on February 13, 2015, within the 10 day window.

The Company's obligation under the PPA is to seek an order from the Commission making the affirmative determination that the Company's execution of the PPA is prudent and/or in the public interest, and that all costs incurred under the PPA are recoverable from our customers subject to ongoing prudency review of Company's performance and administration of the PPA. The Company retains the right to terminate the PPA if the Commission does not approve the PPA, or denies the Company recovery of the costs incurred under the PPA as currently allocated to North Dakota customers by ratemaking mechanisms currently in effect.

We note that this issue touches on a significant policy issue with respect to the impacts of divergent state energy policies on our integrated NSP System in the Upper Midwest. Pursuant to the Settlement Agreement in Case No. PU-12-813, *et. al*, we are currently examining ways that our integrated system can be restructured to avoid the policies of one state having unwanted impacts on the ratepayers of another state.

VIII. PRUDENCE OF THE GERONIMO SOLAR PPA

The Company respectfully requests that the Commission find our proposed acquisition of the up-to-100 MW (nameplate) Geronimo Solar PPA to be prudent under the circumstances. The PPA provides up to 71 MW of MISO accreditable capacity that helps meet the capacity need identified in our 2010 Resource Plan. It provides a carbon-free resource that will help us meet emerging federal and state environmental and renewable energy requirements. It also is consistent with the Company's goal of substantially expanding our solar portfolio during the current planning horizon as described in our 2015 Resource Plan filing. While the Company recognizes that the Geronimo Solar Project is not a least-cost resource on a PVRR basis, we respectfully request approval based on the capacity and environmental compliance benefits that it provides.

We recognize that the timing and staging of new renewable resources such as the Geronimo Solar PPA overlaps with other renewable resource matters currently before the Commission.[20] Xcel Energy acknowledges that our recent 2015 Resource Plan filing shows a modest capacity surplus in the 2017-2019 timeframe. Nevertheless, we believe the selection of this resource at this time is prudent and in the best interest of all of our customers on our integrated system. We also acknowledge that we propose in our 2015 Resource Plan that additional utility-scale solar resources be added to our system in later years.[21] Nevertheless, in this section we explain why we believe the deployment of the Geronimo Solar PPA by 2016 is a prudent choice for our integrated system and, therefore, in the best interests of our customers in North Dakota.

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[20] For example, our recent Resource Plan filing proposes adding 187 MW (nameplate) portfolio of solar PPAs arising from our recent solar RFP, and the Company is currently seeking an ADP for that resource portfolio in Case No. PU-14-810.

[21] We explained in our Resource Plan (which was required to be filed on January 2, 2015) that it does not take into account the Geronimo Solar PPA and the other resources arising out of the MPUC's CAP Docket. The MPUC's December 15, 2014 oral decision and February 5, 2015 written order in the CAP Docket did not permit us to include those resources in the plan.

A. Costs of the Geronimo Solar Project

To evaluate the costs of the up to 100 MW Geronimo Solar Project, we used the Strategist resource planning model, and present the results in terms of Present Value Revenue Requirements (PVRR).[22] Strategist simulates the operation of the NSP System and estimates the total cost of energy over the life of the project on a present value basis. We also use the model to test results under a range of input assumptions. To assess the impact on customer costs, we simulated the operation of the NSP System with and without the addition of the Geronimo Solar PPA. For purposes of this analysis we considered the PPA in isolation and not in combination with the other proposed new generation. In the next section, we provide a similar analysis on various combinations of the three generation resources we propose to be added to the system: the Geronimo Solar PPA, the Calpine Project PPA, and Black Dog Unit 6.

MISO generally dispatches solar production ahead of other generation such as gas and coal-based generation. Consequently, the more solar energy produced, the less fossil generation is operated. Therefore, when the energy from solar resources is produced, it displaces a similar amount of energy that would have been produced by the Company or otherwise purchased elsewhere. The Strategist analysis identifies a displacement of approximately 200,000 MWh of fossil generation, which accounts for the differences in cost of system operation with and without the solar resource addition.

1. Strategist Analysis of Geronimo Solar Project Using North Dakota Resource Planning Assumptions

We used the Strategist resource planning model again to evaluate our resource selection consistent with the requirements of this Commission. We used the same assumptions and forecast information as we did in the CAP Docket but express our modeling results as Present Value of Revenue Requirements (PVRR), consistent with North Dakota law. Our analysis estimates that system costs associated with the addition of the Geronimo Solar PPA are $62 million higher than if the PPA was not added to the system. Table 2 provides the results of this analysis and various sensitivity tests.

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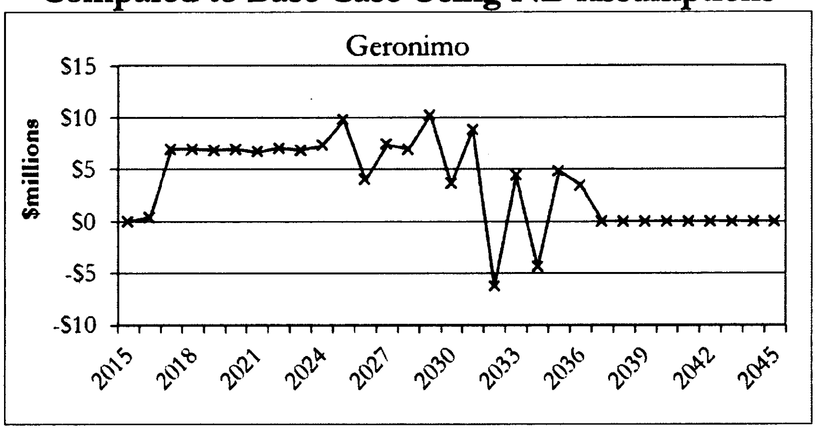
[22] PVRR excludes any assumptions regarding the future cost of CO2 or externalities.

Table 2:
Net PVRR Cost/Savings of Geronimo PPA for Key Sensitivities

Sensitivities =>	Base	2012 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions (PVSC)
Geronimo PPA vs Base Case with ND Assumptions	$62	$71	$76	$44	$49	$35

Figure 5 below illustrates annual net costs or savings over the 20-year life of the Geronimo Solar PPA that lead to the $62 million PVRR impact. As shown over the term, the Geronimo Solar Project moves from net cost to net savings on an annual basis in the out years due to the displacement of thermal resources.

Figure 5:
Annual Net Costs (Savings)
Compared to Base Case Using ND Assumptions



As mentioned, the Geronimo Solar PPA will displace other generation sources that serve the NSP System. Through this displacement of generation, the Geronimo Solar PPA provides the qualitative benefit of hedging our risk with respect to increases in fuel costs by displacing fossil based generation. The displacement of fossil based generation also provides a hedge against future environmental regulation, such as new carbon rules.

Figure 6 below illustrates the results of the Strategist dispatch simulations using the Base Case under North Dakota assumptions (i.e., a "Markets On" scenario with no additional renewable generation and no externalities or carbon cost). In this scenario Strategist may choose to purchase market energy to meet system need. Approximately 60 percent of the solar generation displaces natural gas-based generation, 10 percent displaces coal, and 30 percent displaces market energy.

Figure 6:
Strategist Simulations – Displaced Energy
Base Case Using ND Assumptions

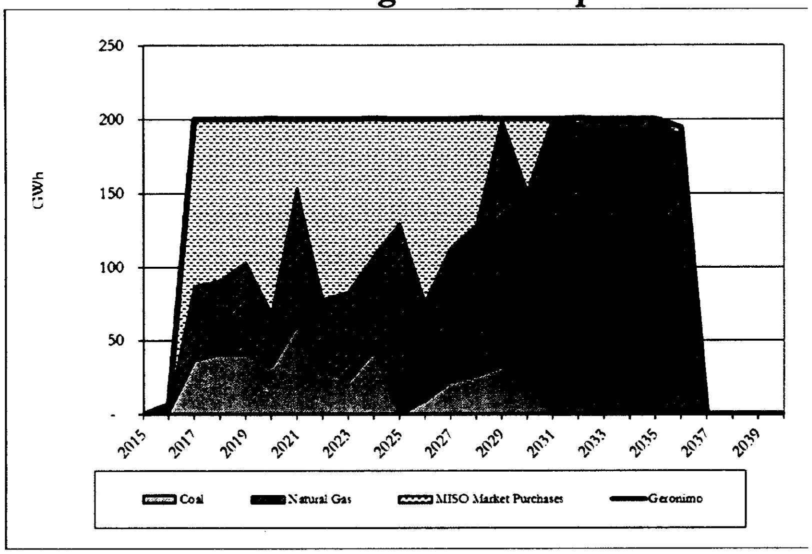
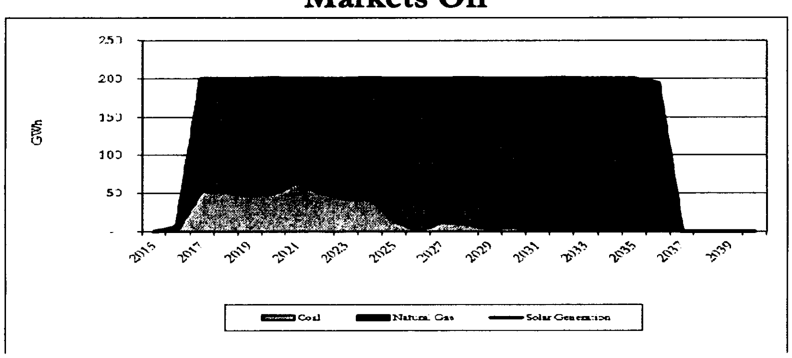


Figure 7 below illustrates the results of the Strategist dispatch simulations under the Markets Off scenario, when just the NSP System is analyzed and only the Company's native generation is displaced by the Geronimo Solar PPA. In this scenario, the majority of the solar generation (approximately 89 percent) displaces natural gas-based generation, with the remaining 11 percent expected to displace coal generation.

Figure 7:
Strategist Simulations – Displaced Energy
Markets Off



As shown, the primary impact of the Geronimo Solar PPA on the operation of the NSP System is displaced generation from fossil fuel resources. This impact provides a qualitative hedge against both future environmental regulations and increases in natural gas prices. We also obtain additional benefits from the Geronimo Solar PPA through the accreditable capacity value of the PPA, which Geronimo has committed will be 71 percent of the nameplate capacity of the PPA, or up to 71 MW.

To further illustrate the hedge value impact of these projects, Table 3 below shows the levels of natural gas consumption and market purchases for the Base Case using North Dakota assumptions (i.e. a view of the NSP System without the Geronimo Solar PPA), and the reduction that would occur in those levels due to the addition of the Geronimo Solar PPA to the system. As shown, the Geronimo Solar PPA is projected to displace 20 Bcf of natural gas and offset over 1.1 million MWhs of market purchases during the PPA's 20-year term. This provides the Company a hedge against increases in the costs of natural gas and market energy.

Table 3:
Hedge Value

Total System 2017-2036	**Natural Gas** *bcf*	**Market Purchases** *GWh*
Base Case Using ND Assumptions	1,466	104,074
Geronimo	(20)	(1,138)

2. Estimated Customer Rate Impacts

While the Geronimo Solar PPA represents a large utility scale solar energy acquisition, we estimate that the customer rate impacts will be mitigated when spread across the entire system because the NSP System is so large in comparison. As shown in Table 4 below, our Strategist dispatch simulation forecasts that for most years, the rate impact of the Geronimo Solar Project will be nearly offset by decreases in the cost of fossil fuel and other purchased energy.

Table 4:
Geronimo Solar PPA Impacts
(¢/kWh)

GERONIMO	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Base Rates	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh
Fuel Clause	0.000¢/kWh	0.001¢/kWh	0.045¢/kWh	0.045¢/kWh	0.046¢/kWh	0.048¢/kWh	0.049¢/kWh	0.050¢/kWh	0.051¢/kWh	0.052¢/kWh	0.053¢/kWh
Avoided Fuel & Purchased Power	0.000¢/kWh	0.000¢/kWh	-0.028¢/kWh	-0.029¢/kWh	-0.030¢/kWh	-0.031¢/kWh	-0.033¢/kWh	-0.033¢/kWh	-0.035¢/kWh	-0.035¢/kWh	-0.030¢/kWh

Table 5 below estimates how average rates will be affected by the proposed solar projects. The initial rate impact of the Geronimo Solar PPA in 2017 is expected to be approximately 0.016¢ per kWh, or about 12¢ per month for a customer using 750 kWh, and stay at that level until 2025 when an expected decreased in the avoided fuel and purchased power benefit increases the net rate impact somewhat.

Table 5:
Geronimo Solar Net Rate Impacts (10 Years)

2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
0.000¢/ kWh	0.001¢/ kWh	0.016¢/ kWh	0.016¢/ kWh	0.016¢/ kWh	0.016¢/ kWh	0.016¢/ kWh	0.016¢/ kWh	0.016¢/ kWh	0.017¢/ kWh	0.023¢/ kWh

B. Other Benefits

In making resource selections, the Company considers factors in addition to cost. A number of those considerations are relevant to the selection of the Geronimo Solar PPA.

1. Capacity Hedge Benefit

Solar generation provides accreditable capacity under MISO's rules, which can be counted toward our load and capability requirements. In the current circumstance, this creates a capacity hedge in the event that our forecast demand rebounds as the economy improves.

Our recent 2015 Resource Plan filing shows a modest capacity surplus in the 2017-2019 timeframe. But as previously described, even small changes in forecast demand can have a significant impact on our supply requirements. If forecast demand changes by even one or two percent, it could wipe out any excess capacity and expose us to the MISO capacity market at a time when a number of baseload capacity resources are being retired, raising the potential for higher prices or even a capacity shortfall.

The Company's current supply portfolio shows a modest amount of excess capacity (between 1 and 2.5%) from 2015 through 2018 and virtually no excess capacity on a system-wide basis in 2019 and 2020. In 2021, the system then regains excess capacity by increasing our current Manitoba Hydro purchase with anticipated new capacity that is under development. In 2024, however, we again show a system deficit of 234 MW. This load balance profile suggests that we are at risk of capacity deficits beginning in 2019 and 2020 if our projected loads change by even a very small amount. Indeed, even the 0.5 to 2.5 percent excess capacity shown on our assumed supply portfolio is modest given the normal forecast variability which can result in demand swings of 200 MW (2 percent) or more.

The 2015 Resource Plan data suggests that we are at risk of capacity shortfalls (both on a system-wide and North Dakota allocated share basis) in 2019-2020 due to small changes in customer loads. The normal variability we have experienced between load projections and actual results in recent years indicates it is appropriate to acquire additional generation as a hedge. While we could potentially purchase short-term capacity from the MISO voluntary capacity market at then-prevailing rates for any capacity shortfall, we must also consider that existing and proposed retirements of baseload units in the MISO footprint may result in a shortfall of capacity, leading to higher capacity prices in the MISO voluntary short-term capacity market. Prudent planning includes balancing the risk of exposure to the capacity market in the next five years against the cost of building additional capacity in the 2019/2020 time-frame, which will be necessary by 2024 in any event.

We also included a scenario in our 2015 Resource Plan analysis which reflects all of our currently contemplated resources. This includes: (1) the 98 MW accreditable capacity (187 MW nameplate) of the solar portfolio which is the subject of Case No. PU-14-810; (2) the 278 MW accreditable capacity (345 MW nameplate) of the Calpine Project PPA; (3) the up-to 71 MW accreditable capacity (up to 100 MW nameplate) of the Geronimo Solar PPA; (4) the 207 MW accreditable capacity (215 MW nameplate) of Black Dog Unit 6; (5) a new short-term (four-year) 75 MW capacity exchange with Manitoba Hydro; and (6) additional resources contemplated by our 2015 Resource Plan.[23] If all of this contemplated new generation is deployed, it will result in a system surplus in the 2019-2020 timeframe of about 6 to 7 percent (550 MW in 2019 and 685 MW in 2020) and address our resource need in 2024.

The following Table 6 provides a summary of the analysis on a system-wide basis:

[2323] Please note, we expect to file for approval for the Manitoba Hydro contract from the Commission in the next several months. Because it is a short-term purchase, approval by the MPUC is not required.

Table 6:
System Capacity Forecast (MW)
(2015 Forecast)

Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Long/(Short) (existing system)	177	142	242	91	8	0	231	182	163	(234)
Resources Approved by the MPUC	-	-	-	71[3]	278[4] 71[3]	207[5] 278[4] 71[3]	556[6]	556[6]	556[6]	556[6]
Proposed Additional Resources	-	73[1]	73[1]	98[2] 73[1]	98[2] 73[1]	98[2]	98[2]	98[2]	98[2]	98[2]
Resources in the 2016 IRP Preferred Plan	-	-	-	-	-	-	89	89	118	171
Aggregate Additional Resources	-	73	73	243	551	684	773	773	803	855
Long/(Short) Position (assumes all additions)	**177**	**216**	**315**	**334**	**559**	**685**	**1,004**	**956**	**965**	**621**
Notes	1- Manitoba Hydro 75 MW additional capacity exchange (four years). 2- 187 MW Solar portfolio (98 MW accreditation) 3- Geronimo Solar Project PPA (2016 in-service; 2018 MISO accreditation) 4- Calpine Project PPA 5- Black Dog Unit 6 6- Geronimo PPA + Calpine Project PPA + Black Dog Unit 6									

We prepared a similar analysis showing the same information on a North Dakota load-allocated basis. The following Table 7 provides the output of that analysis:

Table 7:
North Dakota Allocated System Capacity Forecast (MW)
(2015 Forecast)

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ND as a Percentage of NSP System	4.94	4.99	5.01	5.05	5.08	5.13	5.19	5.22	5.34	5.38
Long/(Short) (existing system)	9	7	7	5	0	0	12	10	9	(13)
ND Allocation of Additional Resources	-	4	4	12	28	35	40	40	43	46
Long/(Short) (assumes all additions)	9	11	11	17	28	35	52	50	52	33

This shows that on a North Dakota allocated basis, there is no excess capacity in 2019 and 2020. While the number increases again in 2021 due to the addition of new capacity from Manitoba Hydro, it is appropriate to plan the system to include additional capacity that addresses the 2019 and 2020 'pinch point' and remains available in 2024 when we begin to experience forecasted capacity deficits.

2. Environmental Hedge Benefits

Solar generation provides an emissions-free energy source that can work well in combination with other capacity resources, such as natural gas facilities. As described above, environmental requirements that impact our integrated system are in a period of significant change. Increasing carbon-free generation will further our goals of early compliance with new and emerging emissions requirements and targets.

This resource addition will also position us to address issues identified in our 2015 Resource Plan beyond 2024. This includes the impacts of pending environmental regulation such as NOx regulations that may impact the continued use of our Sherco Units 1 and 2, as well as EPA's proposed Clean Power Plan. Furthermore, the Geronimo Solar PPA positions us to address known long-term changes to the NSP System that will result in the Company needing to replace or extend the operating lives of nearly 75 percent of the energy producing resources on the NSP System over the next 20 years.

We note that the Company has been a leader in advancing renewable energy in the upper Midwest and has been able to do so at reasonable costs for the most part.

Making choices to increase our renewable energy portfolio provides us with strategic flexibility to continue that leadership as well as ensure compliance with evolving requirements.[24] The Geronimo Solar PPA would be part of that deployment, fitting within our plans for the overall build-out of the integrated system.

3. ITC Qualification Benefit

The Geronimo Solar Project is dependent upon obtaining the 30% ITC to offset a significant proportion of the costs of the project. This tax credit applies to any project that goes into service by the end of 2016. The ITC automatically reduces to 10% for projects that go into service after 2016. We are not assuming that the existing higher ITC rate will be extended past its current expiration date. Further, solar economics are improving as solar installations increase, state and federal incentives continue, and solar technology design and manufacturing improvements advance. Customers are also increasingly interested in new energy choices. And state and federal policies are promoting solar as a way to reduce GHG emissions and support local economic development. Thus, pursuing additional solar generation at this time allows Geronimo to capture the higher ITC rate now and promote these other benefits of solar generation on our integrated system.

C. Analysis of Full Resource Portfolio (Calpine, Geronimo, Black Dog)

To provide context for the Commission's evaluation of our ADP request, we conducted additional analysis for the Commission's consideration. In this Section we provide modeling results that identify the costs of various combinations of the three resources we propose to acquire: Black Dog Unit 6, the Calpine Project PPA, and the Geronimo Solar PPA.[25] These three facilities are all part of the Company's selections to meet our identified capacity need. In the aggregate, these three projects reflect our proposed construction initiative of new generation in the 2016-2019 timeframe.

Tables 8 and 9 below presents the PVRR results of the specified combination of resources and the same sensitivity tests used above for the single facility under consideration in this Case.

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[24] As part of our 2015 Resource Plan, the Company is proposing to add approximately 2,400 MW of utility-scale and customer-driven small solar resources over the next 15 years. This additional solar generation along with other resource choices should position us well for long-term compliance with greenhouse gas reductions. While our Resource Plan contemplates additional utility-scale solar being deployed in 2024 and beyond, we believe it is a reasonable policy choice to advance 100 MW of that target and deploy the Geronimo Solar PPA at this time.

[25] Since the Commission has already granted an ADP for Black Dog Unit 6, the analysis provided here is only intended to inform the Commission's consideration of this ADP application.

Table 8:
PVRR Results ($millions)

Scenarios	Base	2011 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions (PVSC)
Base case using ND Assumptions	$44,949	$49,279	$41,260	$50,050	$45,957	$51,971
Add Geronimo Solar PPA	$45,011	$49,350	$41,336	$50,094	$46,006	$52,005
Add Calpine Mankato CC PPA	$44,937	$49,257	$41,271	$50,010	$45,883	$51,944
Add Black Dog 6	$44,836	$49,162	$41,159	$49,923	$45,825	$51,868
Add Geronimo & Calpine	$45,012	$49,328	$41,358	$50,070	$45,947	$51,992
Add Calpine & BD6	$44,842	$49,155	$41,186	$49,902	$45,767	$51,849
Add Geronimo & Calpine & Black Dog 6	$44,929	$49,219	$41,286	$49,974	$45,842	$51,908

Table 9:
Incremental PVRR from Base Case ($millions)

Scenarios	Base	2011 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions
Base case using ND Assumptions	$0	$0	$0	$0	$0	$0
Add Geronimo Solar PPA	$62	$71	$76	$44	$49	$35
Add Calpine Mankato CC PPA	($11)	($22)	$10	($40)	($74)	($27)
Add Black Dog 6 CT	($112)	($118)	($101)	($127)	($132)	($103)
Add Geronimo & Calpine	$63	$48	$98	$20	($10)	$21
Add Calpine & Black Dog 6	($107)	($124)	($74)	($147)	($190)	($122)
Add Geronimo & Calpine & Black Dog 6	($20)	($60)	$26	($76)	($115)	($63)

Notably, the addition of the Black Dog Unit 6 followed by the combination of Black Dog 6 and Calpine provide the highest PVRR savings. Further, the Geronimo Solar PPA in combination with the Calpine Project PPA and Black Dog Unit 6 provides a net reduction in the PVRR in all scenarios except the low gas case.

Figure 8 below shows the aggregate impact of the Geronimo Solar PPA, the Calpine Project PPA, and Black Dog Unit 6.

Figure 8:
Annual Net Costs (Savings) (without CO2)
Compared to Base Case using ND Assumptions

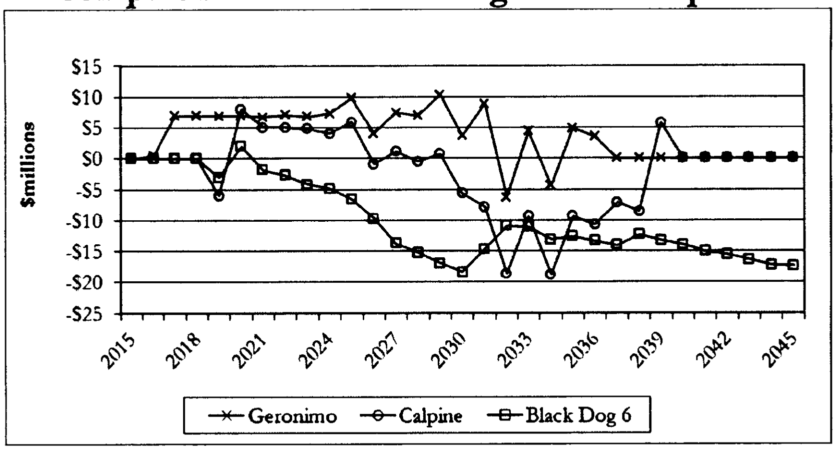

Figure 9 below illustrates the results of the Strategist dispatch simulations using the Base Case under North Dakota assumptions (i.e., a "Markets On" scenario with no additional renewable generation). In this scenario Strategist may choose to purchase market energy to meet system need. Approximately 85 percent of the aggregate generation displaces natural gas-based generation, 16 percent displaces market energy, with coal generation output having a net increase of 1 percent.

Figure 9:
Strategist Simulations – Displaced Energy Base Case Using ND Assumptions for Combination of Geronimo, Calpine, and Black Dog 6 Projects

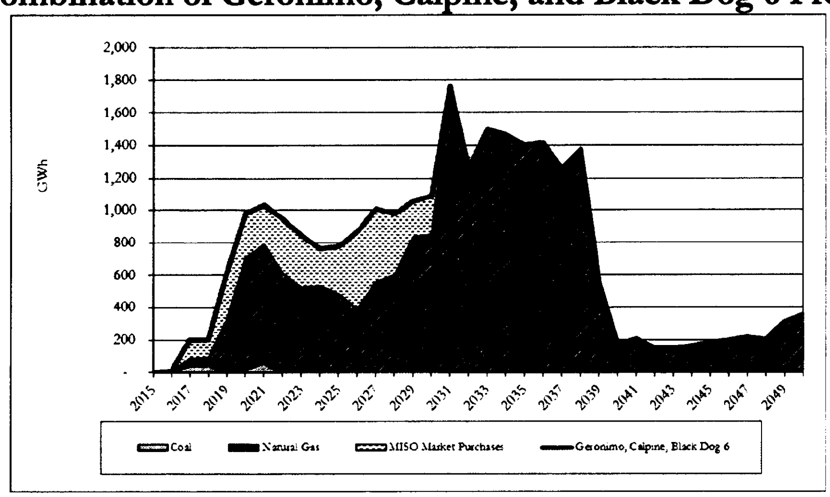

Table 10 below shows the rate impact of the various combinations.

Table 10:
Annual Rate Impact Analysis

GERONIMO	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.017¢/kWh	0.023¢/kWh
CALPINE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.014¢/kWh)	0.019¢/kWh	0.012¢/kWh	0.012¢/kWh	0.011¢/kWh	0.009¢/kWh	0.014¢/kWh
BLACK DOG 6	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.007¢/kWh)	0.005¢/kWh	(0.004¢/kWh)	(0.006¢/kWh)	(0.010¢/kWh)	(0.011¢/kWh)	(0.015¢/kWh)
GERONIMO + CALPINE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.003¢/kWh	0.035¢/kWh	0.027¢/kWh	0.028¢/kWh	0.026¢/kWh	0.032¢/kWh	0.023¢/kWh
CALPINE + BLACK DOG 6	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.021¢/kWh)	0.018¢/kWh	0.029¢/kWh	0.019¢/kWh	0.009¢/kWh	0.006¢/kWh	0.003¢/kWh
GERONIMO + CALPINE + BLACK DOG 6	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.006¢/kWh	0.034¢/kWh	0.055¢/kWh	0.046¢/kWh	0.036¢/kWh	0.021¢/kWh	0.016¢/kWh

IX. CONCLUSION

In conclusion, the Company respectfully requests that the Commission grant an advance determination of prudence for the Company's acquisition of the capacity and energy of the 20-year Geronimo Solar PPA as an appropriate resource for the Company's integrated system. In the alternative, and if the Commission finds that purchasing this capacity is not in our North Dakota customers' best interest, the Company requests that this purchase be found to be appropriate and eligible for inclusion and proxy pricing in the Restack.