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February 13, 2015

- Via Email and Federal Express -

Darrell Nitschke, Executive Director
North Dakota Public Service Commission
State Capitol Building, Dept 408
600 East Boulevard
Bismarck, ND 59505-0480

RE: REQUEST FOR APPROVAL OF AN ADVANCE DETERMINATION OF PRUDENCE
FOR A POWER PURCHASE AGREEMENT WITH MANKATO ENERGY CENTER,
LLC FOR APPROXIMATELY 345 MW OF COMBINED-CYCLE NATURAL GAS
GENERATION
CASE NO. PU-15-_____

Dear Mr. Nitschke:

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 for 345 MW of capacity and associated energy to be added to the NSP System through a 20-year power purchase agreement with Mankato Energy Center, LLC, an affiliate of Calpine Corporation.

The Company's Application contains trade secret information. In accordance with Section 69-02-09-02 of the North Dakota Administrative Code, an Application for Trade Secret Protection is being provided along with a single copy of the trade secret version of the Application and supporting testimony in a sealed envelope marked **TRADE SECRET-PRIVATE**.

An original and nine copies of the public version of our Application are also being provided, along with the following:

- Direct testimonies of Company Witnesses Laura McCarten, Kurtis Haeger and Paul Johnson, supporting the Company's Application;

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- Verifications for the testimonies of Ms. McCarten, Mr. Haeger and Mr. Johnson;
- CD containing the public version of the Application, testimonies and verifications, and Application for Trade Secret Protection; and
- A filing fee of \$175,000.

The Company is providing the \$175,000 filing fee as required by N.D.C.C. § 49-05-16(1)(b).

We look forward to working with the Commission in the review of this filing.

Sincerely,

A handwritten signature in blue ink that reads "David H. Sederquist". The signature is written in a cursive, flowing style.

DAVID H. SEDERQUIST
Sr. Consultant, Regulation & Finance
Enclosures

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**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
MANKATO ENERGY CENTER, LLC FOR
APPROXIMATELY 345 MW OF
COMBINED-CYCLE NATURAL GAS
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) for 345 MW of capacity and associated energy to be added to the NSP System¹ through a 20-year power purchase agreement with Mankato Energy Center, LLC, an affiliate of Calpine Corporation (the Calpine Project PPA).

The Calpine Project's capacity and associated energy will be acquired from a new combined-cycle, natural-gas unit added to Calpine's existing 375 MW Mankato Energy Center located in Mankato, Minnesota, from which the Company purchases capacity and associated energy through an existing 20-year PPA. 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 meet a potential need of 150-500 MW on our system in the 2017-2019 time period that was identified in our 2010 Resource Plan. To meet the need, we are proposing to add three new resources:

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.

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(1) the Calpine Project 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; (3) and the up-to-100 MW (nameplate) distributed solar generation PPA proposed by an affiliate of Geronimo Energy (Geronimo Solar PPA).

As discussed in this Application, 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 (CT) units, with one of the CTs 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.² The Commission found these additions to be prudent and an ADP was granted for each of these resources.³

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.⁴ 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 in the CAP Docket, our analysis showed that Black Dog Unit 6 in conjunction with either the Calpine Project or the Invenergy

² *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.

³ 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.

⁴ *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.

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Project were least-cost options to fill the identified need.⁵ 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.⁶ 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 Calpine Project PPA is a prudent and cost-effective resource to add to our system to meet our identified potential need because it provides the flexibility of a combined cycle unit at a reasonable cost. And when it is paired with the other resources we have selected – Black Dog Unit 6 and the Geronimo Solar PPA – it provides additional diversity of resources on our system to meet our customers’ needs at an overall reasonable cost.

Specifically, the addition of the combined-cycle natural gas capacity and associated energy of the Calpine Project PPA at this time provides the following strategic benefits:

- Competitive pricing that adds capacity to an existing site and provides strategic benefits to the overall system.
- Additional flexible capacity and lower priced energy that will help to ensure our supply portfolio does not fall short in the event that we experience a rebound in load growth in the coming years.
- Intermediate capacity to support and balance the significant and growing levels of intermittent renewable generation on the system.
- Enhanced flexibility to address the known retirements of existing intermediate and baseload generation during the planning horizon.
- Hedging against emerging environmental regulations that make it increasingly likely the Company’s older coal resources will need to be replaced in part with natural gas generation.

The Company recognizes that this ADP replaces the Red River Valley Units - which were found to be a prudent investment by the Commission - with a resource that is, in part, the result of Minnesota’s resource selection process. This Application and

⁵ Gas CT Case, Alders Supp. Testimony at 10-11.

⁶ Gas CT Case, Alders Supp. Testimony, Schedule 2 (Wishart Direct) at 23, and Table 5 at 26.

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supporting testimony will demonstrate the prudence of this resource addition in lieu of moving forward with the Red River Valley Units.

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;
- Calpine Project PPA;
- Prudence of Calpine Project 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

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

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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 other words, we determine the need to add capacity to our system based on 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

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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.

Consequently, 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, and permitting and developing 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

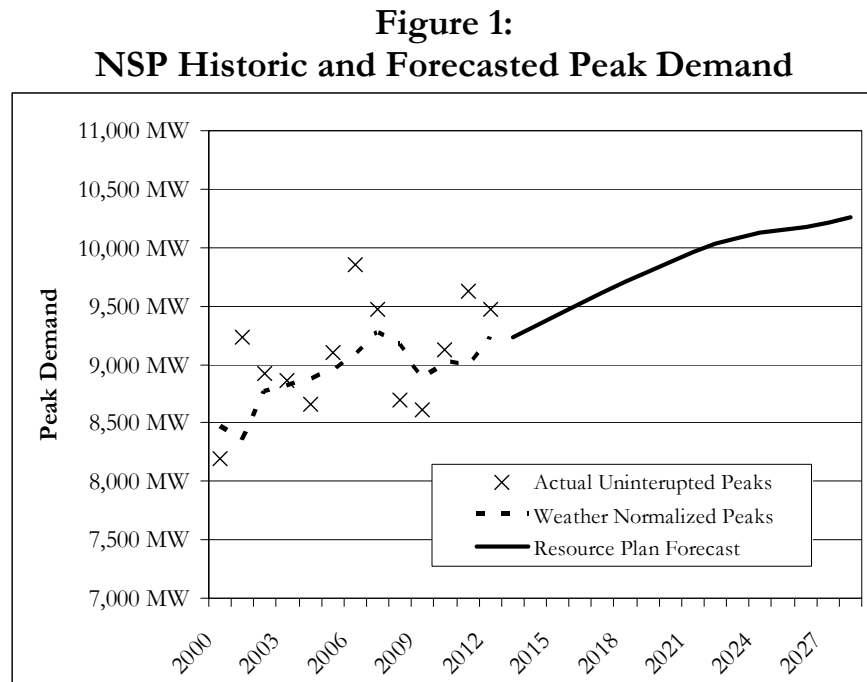
In this Case, the forecast used to establish the capacity need of 150-500 MW was the Company’s updated Fall 2011 Forecast. The Fall 2011 Forecast updated the forecasting analysis in our 2010 resource plan, which first identified our capacity need. Mr. Haeger further describes in his Direct Testimony 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, and we advised that it was prudent to plan to meet the

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identified need in the Fall 2011 Forecast because “this ensures adequate generating capacity under all reasonable circumstances,” while also pointing out that “[a]t the same time, our proposal provides flexibility to adjust the timing of the CT generator additions.”⁷ 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.

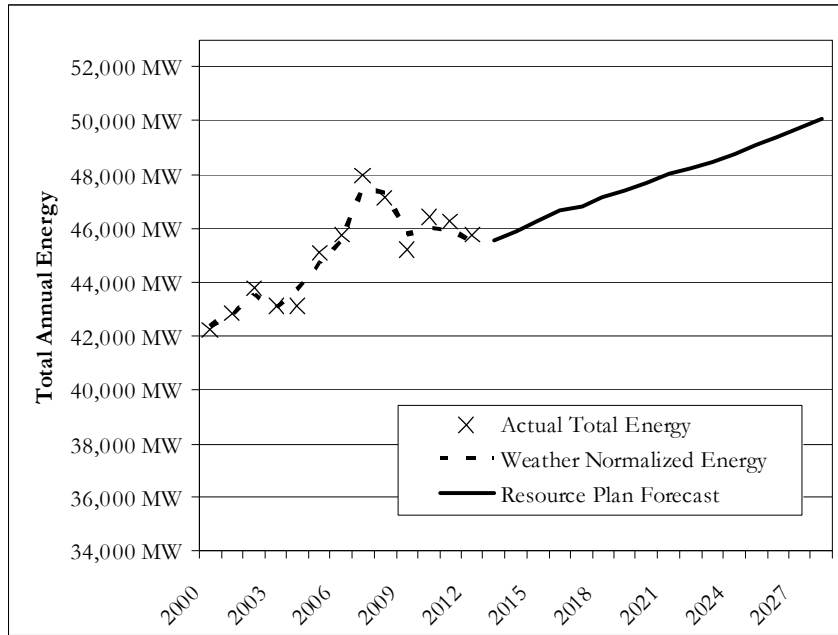


Our total annual energy forecast is shown in Figure 2. The Fall 2011 Forecast assumed an average growth rate from 2013 to 2020 of 0.7 percent.

⁷ Gas CT ADP at 18.

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**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 around 500 MW by 2019-2020 as shown in Table 1 below.

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**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
<u>x 1+RM%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>
= Total Obligation	9,786	9,885	9,977	10,076	10,170	10,255
<u>Resources</u>	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	-	-	-	-	-
<u>Load Management*</u>	<u>1,145</u>	<u>1,153</u>	<u>1,157</u>	<u>1,153</u>	<u>1,149</u>	<u>1,145</u>
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.⁸ 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

⁸ Case No. PU-15-019.

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its system at this time. However, in light of the various reviews and applications of 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.

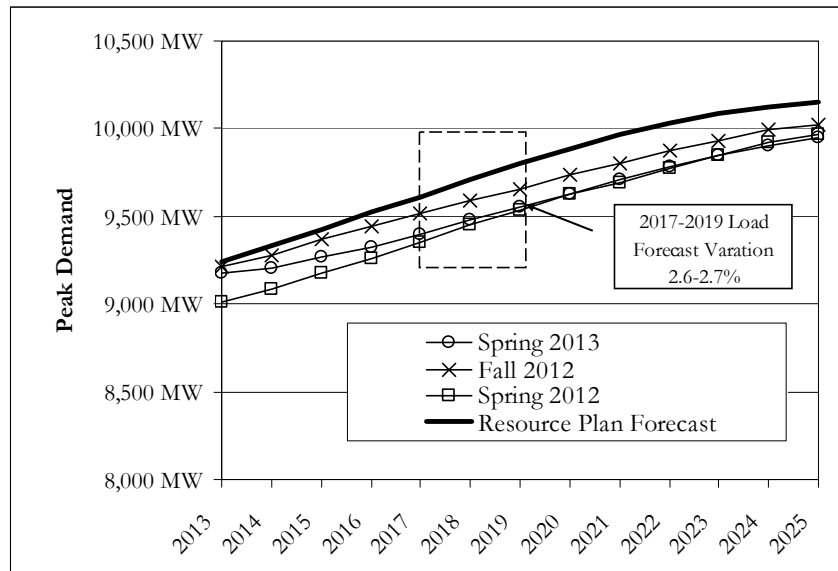
These assumptions can change dramatically with the ups and downs of the economy. It has been difficult to predict what kind of economic conditions will result from the uneven recovery across the region from the 2008 recession. And it continues to be difficult to predict what impact current circumstances, 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 last 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.

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

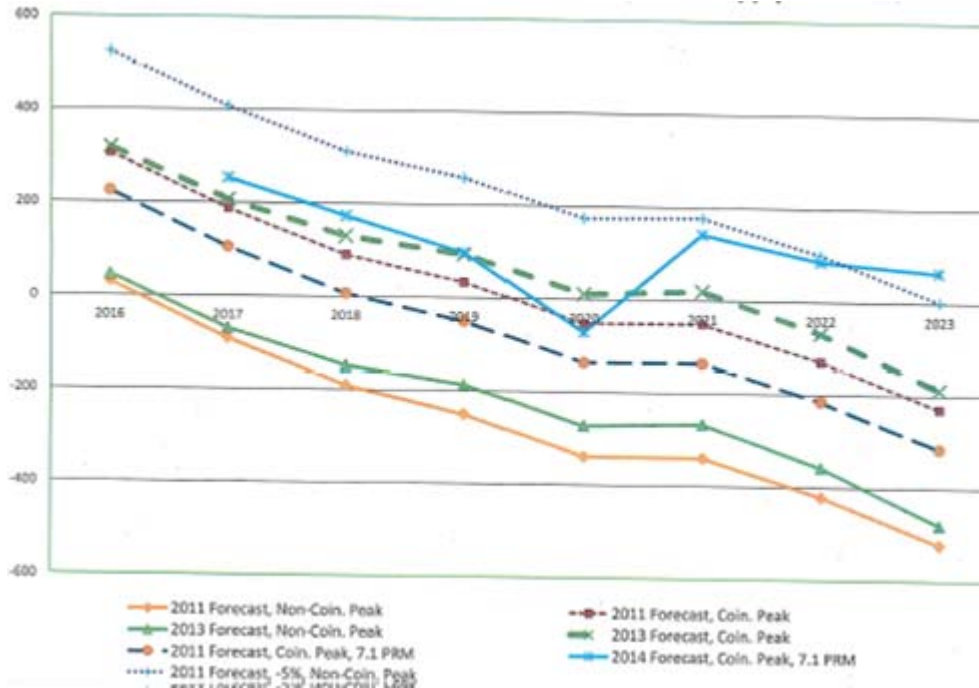


These relatively small variations in our forecasts are primarily a reflection of the inherent uncertainty in forecasting, and we do not believe there is currently any indication of a definitive change in the future peak demand of our customers.

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.

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**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 (Dec. 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

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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.

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 could 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 could 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 even 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

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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 PROCESSES

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. We have been able successfully planning for and managing the integrated NSP System to meet all of our customers' needs for almost 100 years.

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.⁹ This Application is a result of the input provided by the Commission and MPUC through their respective pre-approval processes.

A. 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.

⁹ 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.

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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.¹⁰

In the Settlement Agreement of our 2007 North Dakota rate case,¹¹ the Company agreed to a series of process changes that, among other things, requires 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.¹²

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

¹⁰ In her Direct Testimony accompanying this 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.

¹¹ Case No. PU-07-776.

¹² The Company notes that the Calpine Project PPA is structured in such a way that the Company makes separate payments for both capacity and energy. As a result, this PPA will be somewhat different than other recent PPAs we have brought to the Commission. Traditionally, capacity payments are included in base rates as part of a rate case and the energy payments would be included in our FCR calculations. As described in Ms. McCarten’s Direct Testimony, if this rate treatment is implemented, any base rate impact will occur in 2018 or 2019, which is after the expiration of the rate plan that was agreed to as part of our last rate case.

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2. Minnesota CAP Process

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.¹³ Second, the Company initiates 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 resource planning process. Xcel Energy is subject to the MPUC’s competitive process.¹⁴ 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.¹⁵

The Track 2 CAP consists of the following steps:

¹³ 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.

¹⁴ *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).

¹⁵ 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.

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- 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.

B. 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.

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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. 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. 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.

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, 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

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Dakota loads and the benefits of geographic diversity of generation when compared to other alternatives.¹⁶

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 Capacity)	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 2019.¹⁷

¹⁶ 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.

¹⁷ 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.

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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 beneficial environmental and socioeconomic policies set forth in state statute. The Commission also concluded that the record clearly demonstrated that Black Dog Unit 6, Calpine’s proposed combined cycle unit, and Invenergy’s proposed combustion turbine unit had comparable merits, and that one or more of these three proposed 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 approved the Calpine Project PPA. It also ordered the Company to execute the Calpine Project PPA that is being considered in a separate Case.

C. 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 three gas CTs (about 620 MW accredited capacity) to our system, with the flexibility to implement that proposal consistent with our need materializing.
- The Minnesota process resulted in a 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 556 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 MWs of new capacity, the profile and potential timing of the added generation differs. The benefits of the Calpine Project 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 to the integrated system provides a prudent path forward in light of forecast variability; the need for flexibility in responding to upcoming retirements of intermediate and baseload resources from our system; the significant uncertainty of the impacts of potential environmental regulations on our generation fleet; the overall cost of

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acquiring new resources in the future; evolving market conditions; and our commitment to construct up to 400 MW of thermal generation near our eastern North Dakota loads by 2036 to increase reliability in the region.

We recognize, however, that the Commission may disagree with our concurrence with the MPUC's policy choice to conservatively assess our need, and with its selection of resource additions based on this conservative assessment and Minnesota energy policies. The Commission may determine that the decision to avoid the risk of a shortfall due to the inherent uncertainty in forecasting demand 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 Calpine Project 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. CALPINE PROJECT PPA

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

A. General Description

The Mankato Energy Center is located in Mankato, Minnesota. Calpine's 345 MW combined cycle unit will add approximately 278 MW of accredited capacity to the existing 375 MW (nameplate) Mankato Energy Center. The new CC unit will be located on the same site and incorporated into the existing footprint of Mankato Energy Center's existing CC unit.

Calpine's affiliate and the Company entered into a 20-year PPA with a kW-month price for capacity and MWh price for energy. The proposed capacity and energy

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prices escalate annually after the first year of operation. We anticipate that the new CC will achieve commercial operation in 2018 or 2019.

The payment and other terms in the PPA generally mirror the same terms in the Company's existing Mankato Energy Center PPA with Calpine. By using the existing Mankato Energy Center PPA payment provisions in the new Calpine Project PPA, the administrative burden associated with using two different payment calculations and billing processes for the two PPAs was avoided. It also avoids the risk that unforeseen differences in the payments made and received under different calculation formulas for the two PPAs could have unintended consequences on how the parties choose to schedule, operate, and properly calculate payments for each facility.

We expect that, unless this resource addition is subject to the Restack, we would seek to include the capacity costs of the Calpine Project PPA in base rates in the appropriate rate case, and collect the energy costs of the PPA through our FCR rider.

B. Risk Allocation

The new Calpine Project PPA addresses risks in the following areas:

Potential for Delay/Termination. The Company negotiated options to delay or terminate its PPA in the event future circumstances warrant exercising the options. The Company may delay the facility's COD from 2018 to 2019 subject to the increased capacity and energy prices associated with the new COD, and must also pay for Calpine's demobilization and re-mobilization costs. The Company may also terminate the PPA, paying Calpine for its unrecovered costs, as well as a breakage fee in addition to the unrecovered costs. Total termination fees could be substantial as shown in Trade Secret Exhibit____(KJH-1), Schedule 2.

Transmission Interconnection Costs. The PPA reflects Calpine's proposal that the Company pay for all transmission costs to interconnect the Calpine Project to the grid. Calpine estimated that these costs could run from \$650,000 to \$1.5 million, and the Company has agreed to accept the risk of such costs.

Capacity Accreditation Risk. It appears there are transmission network upgrades that must be made before MISO can accredit the expansion capacity as a Capacity Resource available to the Company, and the completion schedule for these upgrades is beyond Calpine's control. The Company agreed to Calpine's proposal that it may elect to delay COD by one year upon timely notice to the Company that Calpine cannot achieve accreditation by COD. This allows the Company to obtain the

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capacity credit it needs for the year the PPA is delayed from another source, although the cost of the capacity credit will be subject to the prevailing market conditions. Absent such timely notice, Calpine must achieve accreditation by COD, and failure to do so is an Event of Default subject to specific cure provisions designed to keep the Company whole in all events.

Environmental Risk. Calpine proposed that the Company be liable for all costs resulting from future regulation of all types of emissions. The Company strongly objected to its customers incurring these unknowable costs, and Calpine accepted the Company's position that it will only accept conditional risks from the regulation of carbon emissions, consistent with the carbon emissions provision in the Company's model PPA form used to guide negotiations.

Financial Risk. The Calpine Project PPA establishes a pre-COD and post-COD security fund to protect the Company generally from the range of financial risks associated with the PPA. The Company also negotiated a provision requiring Calpine to obtain a subordinated mortgage on the facility upon its completion for the benefit of the Company.

Construction/Operational Risk. The Company negotiated the payment of liquidated damages for each day that Calpine fails to meet COD for the new CC unit due to reasons other than its failure to achieve MISO accreditation of the unit as a Capacity Resource. In addition, the PPA includes other protective measures such as specific performance, step-in rights, actual damages, and termination. The Company also accepted Calpine's proposal that it be allowed to provide energy from an alternative generation source post COD in the event more than 50 MW of the capacity of the new CC unit becomes unavailable due to a forced outage. This holds the Company harmless from a shortfall in meeting its energy needs in the face of a significant outage of the unit

Adding the expansion capacity to the NSP System in June 2018 would result in the addition of approximately [TRADE SECRET BEGINS TRADE SECRET ENDS] of revenue requirements in 2018 and [TRADE SECRET BEGINS TRADE SECRET ENDS] in 2019.

C. Conditions Precedent

The Calpine Project 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 and implementation. There are certain risks

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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.

Calpine must satisfy a number of conditions in order to be obligated to perform under the PPA. These conditions include obtaining an air permit, a site permit and interconnection agreement, and approval of the final PPA by the Calpine Board of Directors after all regulatory approvals have been received, all by specified dates. In the Company's experience, these conditions and the timelines for their completion are typical of the conditions we would expect.

The Company has one important condition precedent. The Company must obtain timely approval of the PPA from this Commission. The Company's obligation is to seek an approval order from the Commission no later than 15 business days after the execution of the PPA, or the Company shall be deemed to have waived its right to seek such approval. The PPA provides that the Company may terminate the PPA if it has not received the requested approval from the Commission by April 1, 2015, but can delay the April 1 deadline to July 1, 2015 with the consequence that the PPA's commercial operation date is delayed until 2019.¹⁸

VIII. PRUDENCE OF THE CALPINE PROJECT PPA

The Company respectfully requests that the Commission find our proposed purchase of the 345 MW Calpine Project PPA to be prudent under the circumstances. The PPA (i) provides capacity that meets our identified need; (ii) is reasonably priced for the benefits provided; and (iii) provides qualitative benefits with respect to anticipated environmental regulation and the retirement of existing baseload and intermediate generation at the end of our current planning period that are not provided by a simple-cycle combustion turbine.

A. Calpine Project PPA Meets Capacity Need

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

¹⁸ Trade Secret Attachment A, Calpine Project PPA at Section 6.1.

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of this resource at this time is prudent and in the best interest of all of our customers on our integrated system.

As described above, even small changes in forecast demand can have a significant result 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 a small amount of 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 that normal forecast variability 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 recognize that 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 across the footprint 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 creditable capacity (187 MW nameplate) of the solar portfolio which is the subject of Case No. PU-14-810; (2) the 278 MW creditable capacity (345 MW nameplate) of the Calpine Project PPA; (3) the up-to 71 MW creditable capacity (100 MW nameplate) of the Geronimo Solar PPA; (4) the 207 creditable capacity of the Black Dog 6

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combustion turbine unit (215 MW nameplate); (5) a new short-term (four-year) 75 MW capacity exchange with Manitoba Hydro; and (6) additional resources contemplated in our 2015 Resource Plan.¹⁹ 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 2 provides a summary of the analysis on a system-wide basis:

**Table 2:
System Capacity Forecast (MW)
(2014 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	529	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 3 provides the output of that analysis:

¹⁹ 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.

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**Table 3:
North Dakota Allocated System Capacity Forecast (MW)
(2014 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.

B. Analysis of Costs and Customer Impacts of Calpine Project PPA

1. Strategist Analysis of Resource Proposals Submitted in CAP Docket

To ensure that sufficient resources were evaluated to cover the high end of potential capacity needs identified in our Fall 2011 Forecast and adopted by the MPUC, the Company modeled portfolios consisting of different combinations of the resource proposals submitted in the CAP docket that ranged from 358 MW to 636 MW.²⁰ The Company’s proposal was to add a single CT unit at its Black Dog plant in 2017, 2018, or 2019, and two CT units at a new Red River Valley plant site near Hankinson, North Dakota in 2018 and 2019.²¹

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

²⁰ Gas CT Case, Alders Supp. Testimony, Schedule 2 (Wishart Direct) at 10-11.

²¹ Gas CT ADP at 2.

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MW in the winter and 215 MW in the summer. The fuel costs were based on the forecasted costs of natural gas at the Ventura hub, with transportation cost adders included to reflect the expected cost at each of the sites. 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.

Based on our Strategist modeling, the Company determined Black Dog Unit 6 was the most cost-effective option as evidenced by the fact that it is included in each of the top 20 resource plans identified in the Company's Strategist analysis.²² We recognize that the Minnesota analysis includes consideration of societal costs that are not considered in the Commission's analysis. The most cost-effective plans identified by Strategist consisted of combinations that included Black Dog Unit 6 being deployed in conjunction with either the Calpine Project or the Invenergy Cannon Falls project.²³ Our modeling did not conclude that the Geronimo Solar Project was a least-cost resource.

As the Commission is aware, we held our proposed Red River Valley Unit 1 in reserve in case the PPAs negotiated with Calpine and Invenergy were not successful. The PPA negotiations were successful, however, and since our analysis showed that the Calpine Project PPA is more reasonable on a Present Value Societal Cost (PVSC) basis than the Red River Valley Units, we continue to believe it is a reasonable choice to hold development of the Red River Valley Units (or some other up-to-400 MW thermal plant(s) in North Dakota) to a future time, consistent with our commitment in the Rate Case Settlement.

2. Strategist Analysis of Calpine 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.²⁴ Table 4 provides the results of this analysis.

²² Gas CT Case, Alders Supp. Testimony, Schedule 2 (Wishart Direct) at 26, Table 5.

²³ Gas CT Case, Alders Supp. Testimony, Schedule 2 (Wishart Direct) at 23.

²⁴ PVRR excludes any assumptions regarding the future cost of CO2 or externalities.

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**Table 4:
Incremental PVRR from Base Case (\$millions)**

Scenarios	Base	2012 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions
Base Case using ND Assumptions	\$0	\$0	\$0	\$0	\$0	\$0
Add Calpine PPA	(\$11)	(\$22)	\$10	(\$40)	(\$74)	(\$27)

In addition, to provide a basis of comparison for the Commission’s consideration, we have evaluated the overall cost of the proposed thermal generation we now intend to add to our system against the cost of adding the three gas CTs to the system, as we originally proposed to the North Dakota and Minnesota Commissions. We provide below the cost of adding Black Dog Unit 6 and the Calpine Project PPA to our system versus the cost of adding Black Dog Unit 6 in combination with the Red River Valley Units using both the Minnesota PVSC and North Dakota assumptions. This provides the Commission with a comparison of the outcome of the Minnesota CAP Docket and the North Dakota Gas CT Case. Table 5 below provides this cost comparison:

**Table 5:
PVSC v. PVRR of Portfolios (\$millions)**

Resource Combination	2013-2050 PVSC (\$millions)	2013-2050 PVRR with ND Assumptions (\$millions)
Calpine PPA + Black Dog 6	\$45,368	\$39,180
Black Dog 6 + RRV 1&2	\$45,404	\$39,198
Cost/(Savings) of Calpine PPA + Black Dog 6	(\$36)	(\$18)

Our cost analysis shows that the acquisition of the 485 MW combination of Black Dog Unit 6 (207 MW accredited capacity) and Calpine Project PPA (278 MW accredited capacity) is less expensive on both a PVRR and PVSC basis than the 621 MW combination of Black Dog Unit 6 and the two Red River Valley Units (207 MW accredited capacity each). This raises the issue whether the additional \$18 million cost associated with the extra 136 MW provided by the combination of the Black Dog and Red River Valley CTs presents more value than the combination of Black Dog Unit 6 with the Calpine Project PPA. The Company believes it does not. As discussed in more detail below, the addition of 278 MW of combined cycle capacity to our system through the Calpine Project PPA provides the Company significant operational flexibility as it faces the loss of intermediate and baseload

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capacity over the next decade as a result of retiring generation units and expiring PPAs.

3. Cost Impact of Calpine Project PPA

As demonstrated above, the selection of Calpine Project PPA was a reasonable and prudent decision based on the alternatives available to us. However, we recognize that taking a conservative approach to the Company's resource needs also requires an analysis of the cost impact of the Calpine Project PPA on our customers so that the benefits and the burdens of undertaking this project can be appropriately evaluated by the Commission. To do this, we used the 2014 load forecast and resource availability assumptions included in our 2015 Resource Plan recently filed with the Commission, which is our most recent load forecast update.

As the Commission knows, 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 Calpine Project PPA. For purposes of this analysis we considered the PPA in isolation rather than in combination with the other proposed new generators. To provide context for our overall resource decisions, we provide in the next section a similar analysis of all the generation selected in the MPUC's CAP proceeding to meet our capacity need.

MISO generally dispatches combined cycle intermediate load units on an economic basis during peak to support and balance baseload units and intermittent resources. The energy produced by an economically dispatched CC unit generally displaces a similar amount of more expensive energy that would have been produced by the Company or otherwise purchased elsewhere. The Strategist analysis identifies a displacement of the approximately 18,300,000 MWh of more expensive generation, which accounts for the differences in the cost of system operations with and without the Calpine Project PPA.

Our analysis estimates that the overall system cost of energy with the Calpine Project PPA added to our system (on a PVRR basis without considering any costs associated with CO₂ emissions or externalities) is \$11 million lower than it would be without the this resource being on our system.

We also conducted various "sensitivity tests" to evaluate how the Calpine Project PPA will affect system costs under different circumstances. The sensitivities analyzed

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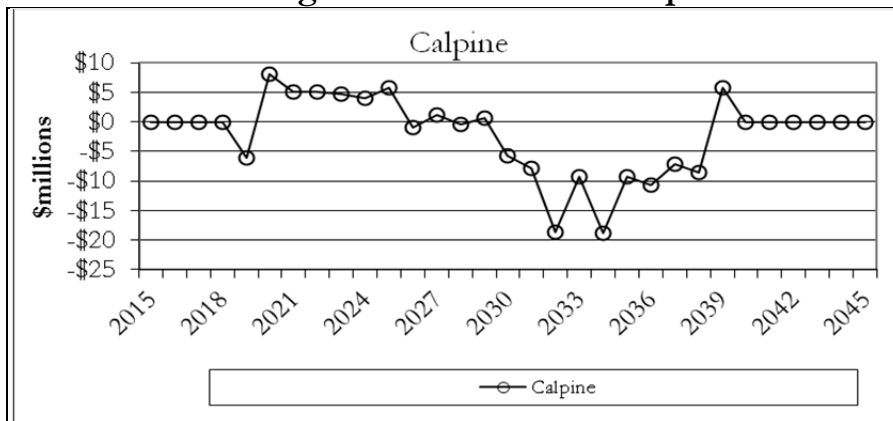
include the effect on system costs if one assumes (i) the Fall 2011 Forecast of capacity need (i.e., a need of 150-500 MWs in the 2017-2019 timeframe), (ii) no MISO market purchases available to supplement system resources (Markets Off), and (iii) higher and lower gas costs. As Table 6 below shows, our economic analysis indicates that the addition of the Calpine Project PPA reduces system costs for all sensitivities except when the price of gas is low.

**Table 6:
Total System Cost With/Without Calpine Project PPA**

Changes in PVRR Cost (\$millions)	Base Case Using ND Assumptions	2012 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions
Base Case Using ND Assumptions	\$44,949	\$49,279	\$41,260	\$50,050	\$45,957	\$51,971
Base Case Using ND Assumptions with Calpine Project PPA	\$44,937	\$49,257	41,271	\$50,010	\$45,883	\$51,944
Net Cost/(Savings)	(\$11)	(\$22)	\$10	(\$40)	(\$74)	(\$27)

Figure 5 below illustrates the year-over-year annual net costs or savings of the Calpine Project PPA during its 20-year life, which results in the net \$11 million savings identified in the table above. Except in 2019, the cost of energy over the first 10 years of the PPA does not offset its capacity cost, while energy savings in the second 10 years of the PPA more than offset its capacity cost to achieve the overall net savings of \$11 million over the PPA’s 20-year term.

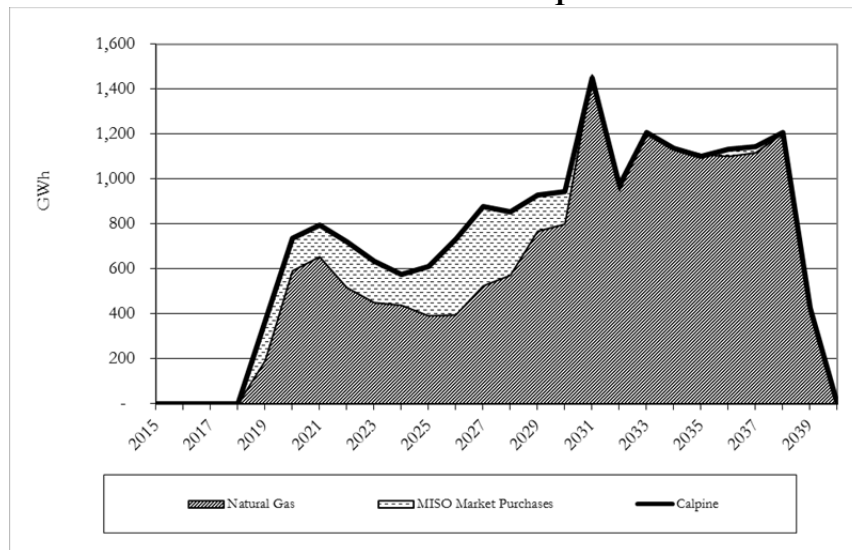
**Figure 5:
Annual Net System Costs (Savings) with Calpine Project PPA Compared to Base Case Using North Dakota Assumptions**



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Figure 6 below illustrates the results of the Strategist dispatch simulations for the Base Case using 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 needs. Over the 20-year term of the PPA, approximately 87 percent of the Calpine Project PPA’s generation displaces other natural gas generation, and 13 percent displaces market energy.

**Figure 6:
Calpine Project PPA – Displaced Energy for Base Case Using
North Dakota Assumptions**



While the Calpine Project PPA represents the addition of a CC unit to our system, the customer rate impacts of the addition will be mitigated when spread across the entire NSP System because the System is so large. As shown in Table 7 below, our Strategist dispatch simulation forecasts for most years shows the rate impact of the Calpine Project PPA (energy and capacity costs) is significantly offset by avoiding higher priced fossil fuel energy and market energy purchases.

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**Table 7:
Calpine Project PPA Impacts
(¢/kWh)**

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Base Rates	0.000	0.000	0.000	0.000¢	0.041	0.070	0.071	0.072	0.0730	0.0730	0.074
Fuel Clause	0.000	0.000	0.000	0.000	0.036	0.077	0.088	0.080	0.073	0.069	0.074
Avoided Fuel/Mkt Purchases	0.000	0.000	0.000	0.000	-0.091	-0.129	-0.148	-0.140	-0.134	-0.133	-0.135

As shown in Table 8 below, the initial net rate impact of the Calpine Project PPA is estimated to be 0.014¢ per kWh in 2019, rising to 0.019¢ per kWh in 2020, and then dropping to and staying at or below 0.012¢ per kWh through 2024 before rising back up to 0.014¢ per kWh again in 2025.

**Table 8:
Calpine Project PPA Net Rate Impacts (10 Years)**

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
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

4. Qualitative Analysis of Benefits of Calpine Project PPA

As mentioned, the Calpine Project PPA will displace other generation sources that serve the NSP System. Through this displacement of generation, the Calpine PPA provides qualitative benefits in the form of hedging against the early retirement of baseload and intermediate capacity from the Company’s system sooner than is currently anticipated. The PPA’s displacement of fossil based generation also provides a hedge against future environmental regulation, such as new carbon rules and any associated costs applied to generation with carbon emissions.

a. Retiring baseload and intermediate capacity

We are entering a period of significant evolution of the NSP System. Although we have built a strong foundation of a diverse and cost effective resource mix, our resource additions should be viewed through the lens of significant change to that mix in the out-years of the Calpine Project PPA and beyond.

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From 2015-2030, the NSP System will experience significant reductions in energy resources due to power contracts expiring without extension or renewal. Several potential key changes include:

- 2023-Blue Lake Units 1-4 cease operation (153 MW)
- 2025-Manitoba Hydro contracts expire (850 MW)
- 2026-Cottage Grove Combined Cycle Energy Center contract expires (262 MW)
- 2027-Mankato Combined Cycle Energy Center contract expires (357 MW)

Further, our resource additions should be viewed in the context of the potential retirement of our three baseload nuclear units, along with the potential end of Sherco Units 1 and 2, which suggest that a significant proportion of our baseload generation may be retired within 15 to 20 years. These five generating units have been the backbone of the NSP System for many years and have formed the foundation to provide low cost and highly reliable service to our customers.

With respect to Sherco, there is the possibility that Unit 1 may be retired as early as 2025, and we have included modeling in our 2015 Resource Plan to identify system requirements in the case that occurs. The addition of the Calpine PPA is a hedge against that possibility. Current technology suggests that natural gas combined cycle units, along with additional renewable energy, will be the likely candidates to replace the energy and capacity these units have provided. As a result of the large potential exposure to add natural gas to our system in the 2025 to 2035 timeframe, the Company must attempt to minimize this exposure going into that timeframe. The addition of the Calpine PPA in 2019 helps mitigate the Company's exposure to this risk, allowing for greater flexibility to respond when our backbone baseload plants are retired.

First, the Calpine PPA locks in very competitive pricing for natural gas combined cycle generation for the next twenty years. Second, this competitively priced capacity resource is capable of intermediate and baseload operation, offering a flexible option to conservatively address the uncertainty of our forecasted capacity need. In addition, the Calpine Project PPA is capable of significant energy production that enhances system flexibility for a variety of system outcomes. Having this operational flexibility and available capacity could become valuable if, for example, Sherco Unit 1 or 2 are retired during the next 20 years due increased environmental compliance costs.

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b. Emerging environmental regulation

We have pursued a strategy of shifting our resource portfolio toward lower-emission options while maintaining our focus on fuel diversity, affordability and reliability. However, we continue to experience significant uncertainty surrounding environmental regulation, which contributes to potential impacts to the NSP System beyond just the resource need that is being addressed by the Calpine Project PPA.

Probably the biggest – and most uncertain – factor is the EPA’s existing source green house gases (GHG) performance standard, known as the Clean Power Plan or Section 111(d) Rules, which Environmental Protection Agency (EPA) expects to finalize in mid-summer 2015. The final rule is likely to face legal challenges which, depending whether or not the rule is stayed during litigation, may affect the timeline for state plan development. If the Rule is not stayed, each state will draft plans and submit them to EPA by 2016 to 2018, for approval by EPA one year later. Compliance will begin in 2020.

While much remains unknown, it seems clear that the Rule will:

- Put increasing pressure on coal plants, possibly resulting in reduced utilization levels or additional retirements;
- Likely increase generation from existing and new natural gas plants; and
- Push us to continue adding renewable energy resources, and increasing energy efficiency efforts and associated investments.

The addition of the Calpine Project PPA hedges against these likely outcomes. It constitutes intermediate capacity that can step in to support the NSP System due to impacts any future environmental regulation may have on our key generating facilities, including our baseload coal units at the Sherburne County Generating Station and our Allen S. King Plant.

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

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.

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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 9 and 10 below present the PVRR results of the specified combinations of resources, and the results of the same sensitivity tests that we conducted for the Calpine Project PPA.

**Table 9:
PVRR Results (\$millions)**

<u>Scenarios</u>	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 10:
Incremental PVRR from Base Case (\$millions)**

<u>Scenarios</u>	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 Calpine Project PPA together with Black Dog Unit 6 provides the most PVRR savings of the combinations analyzed. 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 7 below shows the aggregate impact of the Geronimo Solar PPA, the Calpine Project PPA, and Black Dog Unit 6.

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**Figure 7:
Annual Net Costs (Savings) (without CO2)
Compared to Base Case using ND Assumptions**

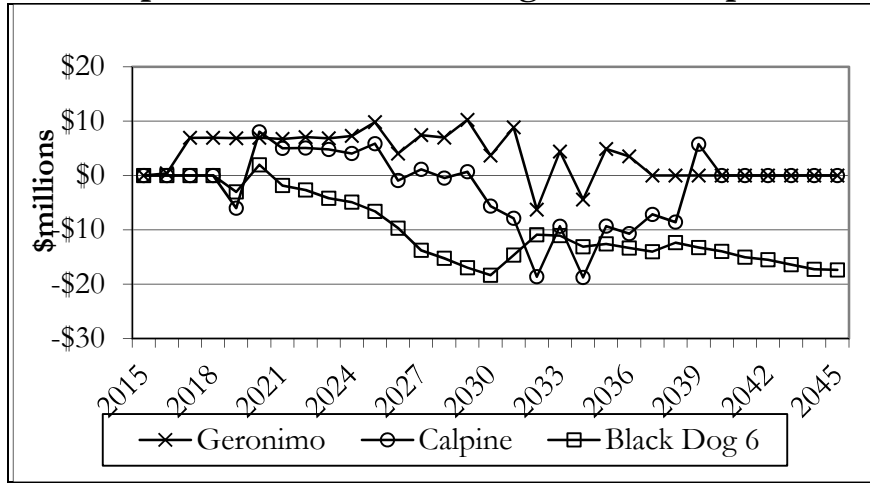
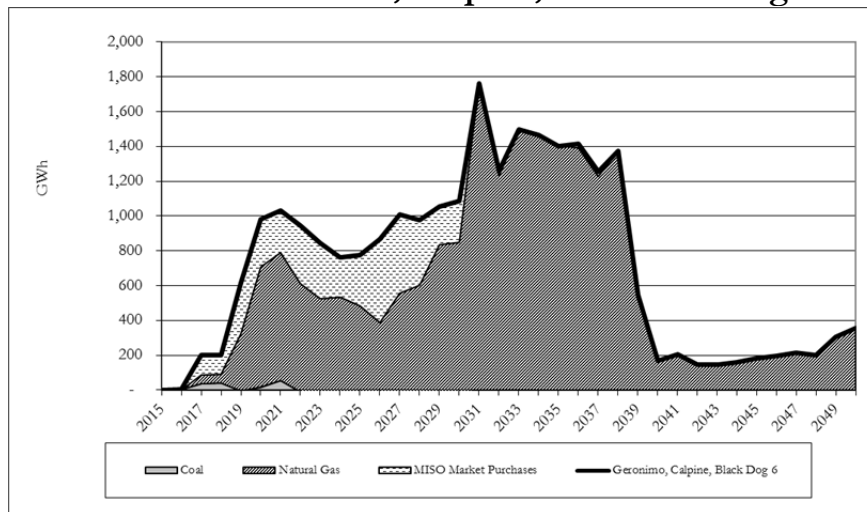


Figure 8 below illustrates the results of the Strategist dispatch simulations for the Base Case using North Dakota assumptions (i.e., a “Markets On” scenario with no additional renewable generation). In this scenario Strategist may choose to purchase market energy to meet system need. Approximately 85 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 8:
Strategist Simulations - Displaced Energy Base Case Using ND Assumptions
for combination of Geronimo, Calpine, and Black Dog 6 Projects**



As shown, the overall impact of adding all three resources on the operation of the NSP System is displaced natural gas generation.

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Table 11 below shows the rate impact of the various combinations.

**Table 11:
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 Calpine Project 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.

Direct Testimony and Schedules
Laura McCarten

Before the North Dakota Public Service Commission
State of North Dakota

Application of Northern States Power Company for an Advance Determination of
Prudence for a Power Purchase Agreement with Mankato Energy Center, LLC for
Approximately 345 MW of Combined-Cycle Natural Gas Generation

Case No. PU-15_____
Exhibit__ (LM-1)

Policy Testimony

February 13, 2015

Table of Contents

I.	Introduction and Qualifications	1
II.	Determination of Need	3
III.	Resource Selection Processes	3
IV.	Proposal to Meet Identified Need	12
V.	Prudence of the Calpine Project PPA	14
VI.	Conclusion	18

Schedules

Resume	Schedule 1
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1 **I. INTRODUCTION AND QUALIFICATIONS**

2

3 Q. PLEASE STATE YOUR NAME AND OCCUPATION.

4 A. My name is Laura McCarten. I am Regional Vice President for Northern
5 States Power Company, doing business as Xcel Energy (Xcel Energy or the
6 Company), operating in North Dakota.

7

8 Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

9 A. I am responsible for community, regulatory, and legislative, relations in
10 North Dakota and South Dakota, and also community relations in
11 Minnesota. I provide strategic leadership regarding the development and
12 implementation of our initiatives to most effectively serve our retail
13 customers and communities. My resume is included as Exhibit ____ (LM-1),
14 Schedule 1.

15

16 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

17 A. I provide support for our request for an Advance Determination of
18 Prudence (ADP) for the Company’s power purchase agreement (PPA) to
19 purchase the output from the 345 MW combine-cycle natural-gas expansion
20 project being developed by an affiliate of Calpine Corporation at the existing
21 Mankato Energy Center (the Calpine Project or the Calpine Project PPA).
22 In my testimony, I:

- 23 • Describe our identified future resource needs and how the Calpine
24 Project PPA addresses those needs;
- 25 • Discuss the multi-state review process for our selection of the Calpine
26 Project PPA and the Company’s commitment to timely file ADPs; and

- 1 • Discuss the rate, regulatory and resource planning impacts of this
2 purchase.

3
4 The Company respectfully requests that the Commission conclude that this
5 proposed resource addition is a prudent addition to the integrated NSP
6 System to help meet an identified capacity need of 150-500 MW on our
7 system in 2017-2019 that was identified in our 2010 Resource Plan.¹

8
9 Q. WHO ARE THE WITNESSES FOR THE COMPANY IN THIS PROCEEDING?

10 A. In addition to my Policy Testimony, the Company sponsors the following
11 witnesses:

- 12 • *Kurtis J. Haeger* – who provides more detailed information with respect
13 to our resource planning efforts and proposed additions; and
14 • *Paul B. Johnson* – who provides information about the Company’s
15 Strategist model used for resource planning.

16
17 Q. IS THE CALPINE PROJECT THE ONLY RESOURCE THE COMPANY IS PROPOSING
18 TO PURSUE AT THIS TIME?

19 A. No. To meet the overall 150-500 MW need identified in our 2010 Resource
20 Plan (Case No. PU-10-580), we are proposing to add three new resources:
21 (1) the Calpine Project PPA that is the subject of this Application; (2) Black
22 Dog Unit 6, a 208 MW combustion turbine that will be owned by the
23 Company and for which we have already received an ADP from the

¹ Subsequent and 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).

1 Commission,² and (3) the output from the up to 100 MW solar project being
2 developed by an affiliate of Geronimo Energy (the Geronimo Solar PPA),
3 that is the subject of an ADP application that is being filed separately.
4

5 **II. DETERMINATION OF NEED**

6
7 Q. WHAT CAPACITY NEEDS HAS THE COMPANY IDENTIFIED IN THE 2017-2019
8 TIME FRAME?

9 A. As described in more detail in Company Witnesses Mr. Kurtis J. Haeger's
10 and Mr. Paul B. Johnson's Direct Testimonies, we have identified a capacity
11 need of up to 500 MW in 2019 for our five-state, integrated system.
12

13 **III. RESOURCE SELECTION PROCESSES**

14
15 Q. HOW DOES XCEL ENERGY PLAN AND MANAGE ITS INTEGRATED SYSTEM?

16 A. The integrated NSP System serves over 1.8 million retail electric customers
17 in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. We
18 plan, operate and generally manage the system on an integrated basis to
19 provide service in all of these states. Because our customers in these five
20 states are served by the same system, we are able to achieve significant
21 economies of scale that provide benefits to all of our customers in all of the
22 states we serve. In fact, we've been able to successfully plan for and manage
23 the integrated NSP System to meet all of our customers' needs for almost
24 100 years.
25

² The Company applied for ADPs for Black Dog Unit 6 along with two other CTs that the Company proposed to meet its capacity need: Red River Valley Units 1 and 2. The Commission granted the ADPs in its February 26, 2014 *Order Adopting Settlement* in Case Nos. PU-13-194 and PU-13-195 (Gas CT Cases).

1 Q. IS THE COMPANY SUBJECT TO ANY SPECIFIC REGULATORY PROCESSES TO
2 PROCURE RESOURCES TO MEET A FORECAST NEED?

3 A. Yes. Each of the states in which we provide electric service has different
4 regulatory constructs and oversight regimes. Three of our states – South
5 Dakota, Wisconsin and Michigan – do not put any preconditions on our
6 resource selection but rather rely on after-the-fact review in rate cases or
7 other after-the-fact review proceedings.

8
9 Minnesota requires a form of preapproval of the resources we select, and in
10 North Dakota we have agreed in a previous rate Settlement Agreements to
11 file our Resource Plans and to request advanced determinations of prudence
12 for significant investments, as allowed under state law.

13
14 Q. WHAT IS THE NORTH DAKOTA RESOURCE ACQUISITION PROCESS THAT THE
15 COMPANY IS OBLIGATED TO IMPLEMENT?

16 A. In North Dakota in Case No. PU-07-776, the Company committed to filing
17 its resource plans with the Commission so that the Commission and its staff
18 may provide input into our current plans. We also committed to seek an
19 ADP for any new resource over 50 MW. Finally, in the settlement of our
20 last rate case (Case No. PU-12-813), we committed that we must obtain an
21 ADP before we can recover the costs of the resource through our Fuel
22 Clause Rider (FCR) mechanism.

23
24 Taken together, the Company views these obligations as creating a resource
25 pre-approval process in North Dakota that 1) defines the timing
26 requirements for filing and 2) results in a Commission prudence
27 determination that is binding in a future rate proceeding.

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I note that under the Calpine Project PPA we obtain both the capacity and energy from the project, but the project is structured in such a way that the Company makes separate payments for both capacity and energy. Traditionally, capacity payments are included in base rates as part of a rate case and the energy payments would be included in our FCR calculations. This is somewhat different from many of our other PPAs where there is no separate capacity payment and all payments are recovered through the FCR. I further note that if base rate treatment is implemented for the capacity payment under the Calpine Project PPA, any base rate impact will occur in 2018 or 2019, which is after the expiration of the rate plan that was agreed to as part of our last rate case.

Q. WHAT IS THE REQUIRED RESOURCE ACQUISITION PROCESS IN MINNESOTA THAT IS APPLICABLE TO THE CALPINE PROJECT PPA?

A. In Minnesota, resource acquisitions are to be reviewed in a two-step process. First, resource needs are determined through the resource planning proceedings before the Minnesota Public Utilities Commission (MPUC).³ Second, the Company undergoes a MPUC-designed competitive acquisition process (CAP) to select the needed resource(s).

Q. WHY DOES MINNESOTA HAVE SUCH A DETAILED RESOURCE ACQUISITION PROCESS FOR XCEL ENERGY?

A. Xcel Energy has a long history of procuring new generation resources through a variety of competitive processes. For at least the last 15 years, the

³ 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.

1 Company has utilized competitive bidding to probe the marketplace and to
2 create price competition for the acquisition of long-term generating capacity.
3 We believe that this is one of the most prudent ways for us to acquire
4 resources and is consistent with the MPUC's encouragement of the use of
5 competitive bidding consistent with Minnesota law.

6
7 During our 2004 Resource Plan in Minnesota, the MPUC became concerned
8 that our competitive bidding processes were not entirely adequate. In
9 particular, in the situation where Xcel Energy is proposing its own resource
10 alternative into the process, the MPUC perceived an inherent conflict of
11 interest in that Xcel Energy is both the evaluator and a bidder. As a result of
12 this concern, the MPUC called upon us to work with stakeholders to
13 develop a resource procurement process that would be fair and transparent
14 to all stakeholders.

15
16 Q. WHAT IS THE BASIS FOR THE MPUC RESOURCE SELECTION PROCESS?

17 A. I am not a lawyer but as I understand it, Minnesota law gives the MPUC
18 authority to select resources based upon competitive processes. Pursuant to
19 Minn. Stat. § 216B.2422, subd. 5, the MPUC is empowered to establish a
20 competitive bidding process to govern Xcel Energy's acquisition of a
21 resource or resources to meet an identified need.⁴ The MPUC implemented
22 this statutory authority during its review of our 2004 Resource Plan.⁵

⁴ *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).

⁵ *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).

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27

Q. WHAT ARE THE PARAMETERS OF THE PROCUREMENT PROCESS THAT WERE DEVELOPED IN THE COMPANY’S 2004 RESOURCE PLAN?

Recognizing the distinction between situations where Xcel Energy is proposing its own resource alternative from those situations where Xcel Energy is not proposing a resource alternative, the MPUC developed a two-track system. This is sometimes referred to as “Track 1” (when no Xcel Energy project is proposed) and “Track 2” (when an Xcel Energy project is proposed).

Q. PLEASE BRIEFLY DESCRIBE THE TRACK 1 PROCESS.

A. 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 proceed through a competitive Request for Proposals (RFP) bidding process. This is intended to ensure that the Company probes the market for cost-effective and appropriate proposals under the circumstances. This 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.

Q. PLEASE DESCRIBE THE TRACK 2 PROCESS.

A. The “Track 2” process applies when the Company seeks to meet its identified resource need with a Company-owned, self-build project. Under the Track 2 process, the MPUC has prescribed the competitive acquisition process or “CAP” mechanism. This process requires that we file a certificate of need for the Company-proposed resource. Then, we solicit and evaluate competing proposals from third-party vendors. The competing proposals

1 are evaluated through a contested case process to provide a thorough record
2 on the relative merits of the proposals. This process is intended to ensure
3 that independent power producers have an opportunity to sponsor
4 alternative proposals to the Company's self-build proposal.⁶

5
6 Q. WHAT ARE THE STEPS IN THE TRACK 2 PROCESS?

7 A. The Track 2 process consists of the following steps:

- 8 1. The MPUC approves the resource need to be addressed in the
9 competitive acquisition process through its resource planning order,
10 which establishes parameters around size, type and timing;⁷
- 11 2. The Company submits its proposal with the information required in
12 Minnesota rules and statutes governing certificate of need applications;
- 13 3. On the same date the Company files its proposal, interested
14 competitors provide their proposals in similar certificate-of-need-like
15 detail, including proposed contract terms;
- 16 4. After the MPUC determines that the proposal filings are adequate, a
17 contested case is conducted before an administrative law judge. At the
18 end of the hearing process the administrative law judge provides
19 findings and recommendations to the MPUC;
- 20 5. The MPUC considers the developed record, issues its resource
21 selection, and grants any associated certificates of need; and

⁶ 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.

⁷ The MPUC found a need for up to 500 MW of additional capacity in Docket E002/RP-10-825. *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 7 (March 5, 2013).

1 6. In the event the MPUC selects a power provider proposal rather than
2 the Company's self-build proposal, the Company and selected power
3 provider have four months to negotiate a power purchase agreement
4 and bring it back to the Commission for approval.
5

6 Q. WHY WAS THE "TRACK 2" PROCESS IMPLEMENTED IN THE SELECTION OF THE
7 CALPINE PROJECT PPA AS A RESOURCE FOR THE COMPANY'S SYSTEM?

8 A. One of the other resources being considered in the Minnesota CAP Docket
9 was the Company's 208 MW Black Dog Unit 6 project. Our proposal to
10 consider a self-build and Company-owned project triggered the track 2
11 process.
12

13 Q. WAS THE TRACK 2 PROCESS UTILIZED PRIOR TO THAT PROCEEDING?

14 A. No. The Track 2 process was adopted by the MPUC in 2006 as part of our
15 2004 Resource Plan proceeding in Minnesota. After that time, we had a
16 number of resource acquisitions that were focused on PPA resources where
17 the Company did not seek to offer an alternative resource. In addition we
18 had several competitive bid situations where third party vendors bid
19 resources that were intended for us to purchase the asset once it was
20 constructed. Since the Company was not proposing a self-build option in
21 any of those processes, the Track 2 process was not triggered. As a result,
22 the CAP Docket was our first opportunity to employ this process and we
23 did not have a great deal of experience in implementing it.
24

25 Q. WHAT WAS THE OUTCOME OF THE MINNESOTA CAP DOCKET?

1 A. The MPUC selected three capacity resources to meet the identified capacity
2 need. They were: Black Dog Unit 6, the Calpine Project and the Geronimo
3 Solar Project.

4
5 In its May 23, 2014 Order explaining its resource selections, the MPUC took
6 a conservative approach to ensure we have adequate capacity in place for the
7 Company to meet all of its customers' requirements. Recognizing that the
8 record in that proceeding contained a variety of forecasts and predictions of
9 evolving Midcontinent Independent System Operator, Inc., (MISO) capacity
10 requirements the Company must meet, the MPUC concluded that the
11 resulting uncertainty warranted selecting resources that delivered enough
12 capacity to avoid a potential shortfall in its ability to meet customer
13 demand.⁸

14
15 In its recent Order of February 5 in the CAP Docket, the MPUC reaffirmed
16 these selections and approved the Calpine Project PPA. It also ordered the
17 Company to execute the Calpine Project PPA that is being considered in a
18 separate Case.⁹

⁸ 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.

⁹ *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 CTs Case, Supplemental Testimony of James R. Alders (Alders Supp. Testimony) (Nov. 12, 2013) at 12.

1 Q. DOES THE SELECTION OF THE CALPINE PROJECT MEAN THAT XCEL ENERGY
2 NO LONGER INTENDS TO CONSTRUCT GENERATION IN NORTH DAKOTA?

3 A. No. The Company recognizes that this ADP, in part, replaces the Red River
4 Valley Units, which have already been deemed prudent by the Commission,
5 with a resource that is, in part, the result of Minnesota's resource selection
6 process. We hope to demonstrate the prudence of this resource addition.
7 But it does not diminish the commitment we made in the settlement of the
8 last rate case to construct up to 400 MW of thermal generation near our
9 eastern North Dakota loads by 2036 to increase reliability in the region.

10

11 Q. WHAT ARE SOME OF THE IMPLICATIONS OF THIS RESOURCE SELECTION IN
12 NORTH DAKOTA?

13 A. We believe that our resource choices are reasonable under the
14 circumstances. When considering the 10,000 MW integrated NSP System,
15 we believe it is appropriate for us to choose resources that balance the needs
16 of all of our stakeholders. While this may mean that the size, type and
17 timing of resource selections may not be exactly consistent with each
18 jurisdiction's energy policies, the overall effect on the system remains
19 consistent with our goal to provide high-quality and cost-effective service to
20 all of our customers in all of our states. In other words, we believe that the
21 benefits of the integrated system outweigh the costs and policy choices that
22 the multi-state system requires us to make.

23

24 Mr. Haeger discusses the implications of a Commission denial of an ADP
25 for this resource addition on both our Restack Agreement negotiations and
26 in the event the resource is not subject to the eventual Restack Agreement
27 process further in his Direct Testimony.

1 **IV. PROPOSAL TO MEET IDENTIFIED NEED**

2
3 Q. PLEASE DESCRIBE THE CALPINE PROJECT THAT IS PROPOSED TO BE ADDED
4 TO THE SYSTEM.

5 A. The Mankato Energy Center is located in Mankato, Minnesota. The Calpine
6 Project will add approximately 345 MW of capacity to the existing 375 MW
7 Mankato Energy Center. The new capacity will be incorporated into the
8 existing natural gas combined cycle facility to be built at its existing 375 MW
9 Mankato Energy Center combined cycle plant. The expansion project will
10 be located on the same site and will be incorporated into the existing
11 footprint.

12
13 Calpine’s affiliate and the Company entered a 20-year PPA with a kW-month
14 price for capacity and MWh price for energy. The proposed capacity and
15 energy prices escalate annually after the first year of operation. We
16 anticipate that the expansion project will achieve commercial operation in
17 2018 or 2019.

18
19 The payment and other terms in the PPA generally mirror the same terms in
20 the Company’s existing Mankato Energy Center PPA with Calpine. By using
21 the existing Mankato Energy Center PPA payment provisions in the new
22 Calpine Project PPA, the administrative burden associated with using two
23 different payment calculations and billing processes for the two PPAs was
24 avoided.

25
26 Q. WHY IS THIS PROPOSAL A PRUDENT WAY TO ADDRESS THE IDENTIFIED
27 RESOURCE NEED?

1 A. The Calpine Project PPA provides commercially-reasonable terms and
2 conditions and is at a competitive price. Mr. Johnson’s Direct Testimony
3 provides an analysis of the costs of this contract.
4

5 Q. HOW DO THE COSTS OF THE CALPINE PROJECT PLUS BLACK DOG UNIT 6
6 COMPARE TO THE RED RIVER UNITS COUPLED WITH BLACK DOG 6
7 PROPOSED BY THE COMPANY AND ALREADY APPROVED BY THE NORTH
8 DAKOTA COMMISSION?

9 A. Using the same analysis that was used to support the selection of those units,
10 the Calpine/Black Dog combination is less costly on a Present Value of
11 Revenue Requirements (PVRR) basis than the Red River/Black Dog
12 combination previously considered. On a system-wide basis, PVRR cost
13 difference (using North Dakota modeling inputs) is about \$18 million lower.
14 Mr. Johnson’s direct testimony provides our Strategist analysis showing the
15 projected costs of each resource option.
16

17 Q. ARE THE COMPANY’S OBLIGATIONS UNDER THE PPAs CONDITIONED ON
18 APPROVAL OF THE COMMISSION?

19 A. Yes. All of the relevant agreements contain what is known as a “condition
20 precedent,” which requires that the Commission grant “State regulatory
21 Approval” such as an ADP for each of the projects *before* the Company is
22 required to perform under the contracts. We also have the right to waive the
23 condition precedent and move forward with the projects if all required
24 regulatory approvals are not timely attained.
25

1 **V. PRUDENCE OF THE CALPINE PROJECT PPA**

2
3 Q. WHAT IS THE COMPANY'S REQUEST IN THIS CASE?

4 A. Xcel Energy respectfully requests that the Commission find that our 20-year
5 PPA to purchase the output of the Calpine Project is prudent. Specifically,
6 the addition of the combined-cycle natural gas capacity and associated
7 energy of the Calpine Project PPA at this time provides the following
8 benefits:

- 9 • Competitive pricing that adds capacity to an existing site and provides
10 strategic benefits to the overall system.
- 11 • Additional flexible capacity and lower priced energy that will help to
12 ensure our supply portfolio does not fall short in the event that we
13 experience a rebound in load growth in the coming years.
- 14 • Intermediate capacity to support and balance the high levels of
15 intermittent renewable generation on the system.
- 16 • Enhanced flexibility to address the known retirements of existing
17 intermediate and baseload generation during the planning horizon.
- 18 • Hedging against emerging environmental regulations that make it
19 increasingly likely the Company's older coal resources will need to be
20 replaced in part with natural gas generation.

21
22 Q. WHY DOES XCEL ENERGY THINK IT IS PRUDENT TO PURCHASE THE OUTPUT
23 OF THIS PROJECT AT THIS TIME?

24 A. The selection of this resource at this time is prudent and in the best interest
25 of all of our customers on our integrated system. As Mr. Haeger's Direct
26 Testimony addresses, even small changes in forecast demand can have a
27 significant result on our supply requirements. We conclude that it is

1 appropriate to plan conservatively and deploy resources that will allow us to
2 meet our customers' requirements under all reasonable circumstances.

3
4 Q. ARE THE COSTS OF THE CALPINE PROJECT PPA REASONABLE UNDER THE
5 CIRCUMSTANCES?

6 A. Yes. Mr. Johnson's direct testimony provides our Strategist analysis
7 supporting the costs of this resource.

8
9 Q. ARE THERE OTHER REASONS WHY THIS PURCHASE IS PRUDENT AT THIS TIME?

10 A. Yes. First, the larger MISO region is expecting a number of large baseload
11 coal plants to be retired in the next few years. Adding capacity on our
12 system will hedge the potential tight capacity market that could develop in
13 the region.

14
15 Second, we are entering a period of significant evolution of the NSP System.
16 As described in more detail by Mr. Johnson's Direct Testimony a significant
17 portion of our supply portfolio will need to be addressed by 2035.

18
19 Q. WHAT IS THE STATUS OF THE COMPANY'S SHERCO UNITS 1 AND 2 COAL
20 PLANT?

21 A. The future of Sherco Units 1 and 2 is of considerable importance to the
22 Company and our stakeholders. We anticipate that without the installation
23 of costly Selective Catalytic Reduction technology (SCRs), these units could
24 not operate beyond 2030 under likely to be promulgated environmental
25 requirements, which are currently being challenged in the courts. Our
26 current analysis, assuming these environmental regulations are ultimately
27 imposed, indicates that we can continue to operate Sherco Units 1 and 2

1 until approximately 2030 without having to install SCRs at the plants.
2 However, depending on the final makeup of the applicable environmental
3 requirements, the need to add SCRs could come sooner or later than 2030.
4 As described in more detail in our 2015 Resource Plan, some of our
5 stakeholders would prefer that these units be retired earlier while others may
6 desire that the investments be made to preserve the potential for extended
7 operations.

8
9 No decision on the future of Sherco Units 1 and 2 has been made. Indeed,
10 we anticipate the future and resolution of Sherco Units 1 and 2 will result in
11 a significant policy debate among all of our stakeholders. Nevertheless, it
12 will be important for the Company to have options in place to address the
13 eventual outcome of that debate. Adding carbon-free generation to the
14 system now provides flexibility as the policy debates on our supply mix play
15 out.

16
17 Further, our resource additions should be viewed in the context of the
18 potential retirement of our three baseload nuclear units, along with the
19 potential end of Sherco Units 1 and 2, which suggest that a significant
20 proportion of our baseload generation may be retired within 15 to 20 years.
21 These five generating units have been the backbone of the NSP System for
22 many years and have formed the foundation to provide low cost and highly
23 reliable service to our customers.

24
25 Q. WHAT OTHER QUALITATIVE FACTORS CONTRIBUTE TO THE PRUDENCE OF
26 THIS RESOURCE CHOICE?

1 A. We have pursued a strategy of shifting our resource portfolio toward lower-
2 emission options while maintaining our focus on fuel diversity, affordability
3 and reliability. However, we continue to experience significant uncertainty
4 surrounding environmental regulation, which contributes to potential
5 impacts to the NSP System beyond just the resource need that is the subject
6 of the proceeding.

7

8 Q. ARE THERE MECHANISMS AVAILABLE THAT CAN MITIGATE THE IMPACT OF
9 THE COMMISSION REJECTING THE COMPANY'S REQUEST ON THE
10 INTEGRATED SYSTEM?

11 A. Yes. As the Commission is aware, the proposed Restack Agreement is
12 designed to address just such a situation. At a high-level, adding a resource
13 to the "restack process" will ensure that the Company's North Dakota
14 customers pay the marginal cost for the used and useful capacity and energy
15 of any resource addition that the Company makes but which is denied by
16 this Commission. We are currently negotiating a Restack Agreement with
17 Staff consistent with the settlement of our last rate case (Case No. PU-12-
18 813). Should the Commission not deem the Calpine Project PPA prudent,
19 we believe that this resource would be available to be included in that
20 agreement.

21

22 Q. WHAT ADVANTAGES DOES UTILIZING THE RESTACK PROCESS FOR THIS
23 RESOURCE ADDITION PROVIDE?

24 A. I reiterate that we believe that our resource addition is prudent and
25 respectfully request that the Commission grant our request for an ADP.
26 However, in the event that the Commission denies our request, we believe
27 that the Restack process provides a reasonable short- to mid-term solution

1 to mitigate the effects of the divergent energy policies in Minnesota and
2 North Dakota.

3
4 The Restack concept recognizes the used and useful nature of the capacity
5 and energy of our resource additions to the entirety of the Integrated
6 System, including North Dakota. By doing so it, it continues to allow us to
7 plan to meet the needs of all of our jurisdictions on an integrated basis. The
8 restack process also mitigates the cost impacts of certain policy choices of
9 other states on our North Dakota customers. By providing this interim
10 solution, an effective Restack Agreement will allow us the necessary time to
11 develop a more permanent long-term solution in the context of an evolving
12 utility industry and NSP System.

13
14 Mr. Haeger provides additional discussion with respect to the Restack
15 Agreement and its effects on our integrated planning efforts in his Direct
16 Testimony.

17 18 **VI. CONCLUSION**

19
20 Q. PLEASE SUMMARIZE YOUR TESTIMONY.

21 A. The Company respectfully requests that the Commission grant an ADP for
22 this resource. While we recognize that the competing policies among our
23 states raise important issues for the Commission to consider, on balance we
24 believe this resource is a prudent addition to our integrated multi-state
25 system and it provides a cost-effective way to address the capacity need that
26 has been identified.

27

- 1 Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?
- 2 A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION
OF NORTHERN STATES POWER
COMPANY FOR AN ADVANCE
DETERMINATION OF PRUDENCE FOR
A POWER PURCHASE AGREEMENT
WITH MANKATO ENERGY CENTER,
LLC FOR APPROXIMATELY 345 MW OF
COMBINED-CYCLE NATURAL GAS
GENERATION

Case No. PU-15-_____

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Laura McCarten, being first duly sworn on oath, deposes and says that she is the Regional Vice President for Applicant Northern States Power Company, in the above captioned matter, that she has read the testimony and schedules submitted in the above captioned matter under her name, that they were prepared under her direction, that she knows the contents thereof, and that the same is true and correct to the best of her knowledge and belief.

Laura McCarten

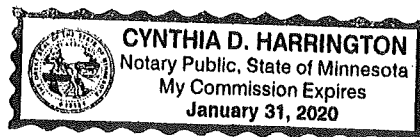
Laura McCarten

Subscribed and sworn to before me this 12 day of February, 2015.

Cynthia D. Harrington

Notary Public

My Commission Expires: 1-31-2020



Laura McCarten

Experience	2008-Present	Northern State Power-MN	Minneapolis, MN
	Regional Vice President, NSPM		
	<ul style="list-style-type: none">▪ For Xcel Energy's North Dakota service territory, responsible for regulatory and legislative interface and strategies, customer and community relations and public affairs, gas business development, and provide strategic leadership on initiatives to effectively serve customers.▪ For Xcel Energy's Minnesota service territory, responsible for community, state government and media relations.▪ For Xcel Energy's South Dakota service territory, responsible for regulatory and legislative interface and strategies, customer and community relations and public affairs, and provide strategic leadership on initiatives to effectively serve customers.		
	2006-2008	Xcel Energy	Minneapolis, MN
	Director, Regional Transmission Development		
	1997-2005	Xcel Energy	Minneapolis, MN
	Director, Minnesota Community Services		
	1994-1997	Xcel Energy	Mankato, MN
	Regional General Manager		
	1992-1994	Northern States Power	Minneapolis, MN
	Manager, Regulatory Affairs		
	1979-1991	Northern States Power	Minneapolis, MN
	Nuclear Generation: Spent Nuclear Fuel Project Manager, Engineer		
Education	1979	University of Wisconsin	Madison, WI
	Bachelor of Science in Nuclear Engineering		
Professional Development	<ul style="list-style-type: none">▪ Xcel Energy Leadership Advantage Program (2004)▪ University of Michigan Business School, Strategic Marketing Planning (1998)▪ University of Minnesota, Carlson School of Management, Minnesota Management Institute (1996)		
Community Service	<ul style="list-style-type: none">▪ Minneapolis Regional Chamber of Commerce, Chair of Board of Directors▪ North Central Electrical League, Board of Directors▪ Ordway Center for the Performing Arts, Board of Directors		

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Direct Testimony and Schedules
Kurtis J. Haeger

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company for an
Advance Determination of Prudence for a Power Purchase Agreement with
Mankato Energy Center, LLC for approximately 345 MW of Combined-Cycle
Natural Gas Generation

Case No. PU-15-_____
Exhibit ____ (KJH-1)

Resource Planning Policy Testimony

February 13, 2015

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TABLE OF CONTENTS

I.	Introduction	1
II.	Resource Need	2
III.	Implications of Need Assessment	6
IV.	MPUC Assessment of Need	10
V.	Company ADP Request	13

Schedules

Resume
Calpine Project PPA

Schedule 1
Trade Secret Schedule 2

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I. INTRODUCTION AND QUALIFICATIONS

1
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27

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Kurtis J. Haeger. I am the Managing Director of Resource Planning for Xcel Energy Services Inc. (XES), the service company subsidiary of Xcel Energy.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have been employed by Xcel Energy or one of its predecessors for over 30 years and assumed my current position as Managing Director of Resource Planning in 2004.

I am responsible for managing the development and implementation of the electric resource plans for all the Operating Companies of Xcel Energy. I also have responsibility for managing the bidding and evaluation processes for acquiring new electric generation resources and for managing the technical analysis for supporting Xcel Energy’s regulatory filings associated with its requests to construct and own new generation facilities. Additionally, I am responsible for directing the analytical support for Xcel Energy’s renewable energy plan filings.

My resume is provided as Exhibit____(KJH), Schedule 1

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I present the resource planning policy issues related to the Company’s requested Advanced Determination of Prudence (ADP) for the Calpine Project power purchase agreement (PPA), which is included as Trade Secret

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1 Exhibit___(KJH-1), Schedule 2 to my testimony. More specifically, I address
2 the following:

- 3 • The Company’s utilization of its Fall 2011 Forecast to establish this
4 need that is being met by the Calpine Project PPA;
- 5 • The impacts that demand forecast variability have on the nature and
6 timing of our resource acquisition decisions; and
- 7 • The impacts o four proposed resource acquisitions on the “Restack”
8 concept established in the Settlement Agreement in Case No. PU-12-
9 813.

II. RESOURCE NEED

10
11
12
13 Q. IS THE COMPANY PROPOSING ITS RESOURCE ADDITION TO MEET AN
14 IDENTIFIED NEED?

15 A. Yes. The Company has identified a need of between 150-500 MW of
16 additional capacity in the 2017-2020 time frame. Company Witness Mr. Paul
17 B. Johnson discusses this need further in his Direct Testimony.

18
19 Q. HOW DID THE COMPANY IDENTIFY THIS NEED?

20 A. Our capacity need is based on our updated Fall 2011 forecast (Fall 2011
21 Forecast). This forecast updated the initial demand and energy forecast
22 included in our 2010 Resource Plan.

23
24 Q. DID THIS INFORMATION ALSO FORM THE BASIS UNDERLYING THE COMPANY’S
25 FILINGS IN CASE NO. PU-13-194?

26 A. Yes, augmented with information from the Company’s Spring 2013 forecast,
27 the Fall 2011 Forecast is the forecast used in our advance determination of

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1 prudence application for Black Dog Unit 6 and Red River Valley Units 1 and 2
2 (Case No. PU-13-194 (Gas CTs Case)). Mr. Johnson discusses in his Direct
3 Testimony our resource planning efforts that led to our proposal in the Gas
4 CTs Case.

5
6 Q. WHAT NEED DID THE 2010 RESOURCE PLAN FORECAST IDENTIFY?

7 A. The initial forecast presented in our 2010 Resource Plan (Case No. PU-10-
8 580) identified a resource need of 963 MW BY 2020 AND 2,003 MW BY 2025.
9 To meet that need, the 2010 Resource Plan proposed a 680 MW combined
10 cycle gas plant to be built at the Company's existing Black Dog site along with
11 780 MW of combustion turbines (CT) by 2024.

12
13 Q. WHAT NEED DID THE FALL 2011 FORECAST IDENTIFY?

14 A. The Fall 2011 Forecast identified a capacity need of approximately 150 MW
15 beginning in 2017 that grows up to approximately 500 MW in 2019/2020, and
16 suggested a capacity need growing to 920 MW by 2024.

17
18 Q. WHAT ACCOUNTS FOR THE DIFFERENCE BETWEEN THE 2010 RESOURCE PLAN
19 FORECAST AND THE FALL 2011 FORECAST?

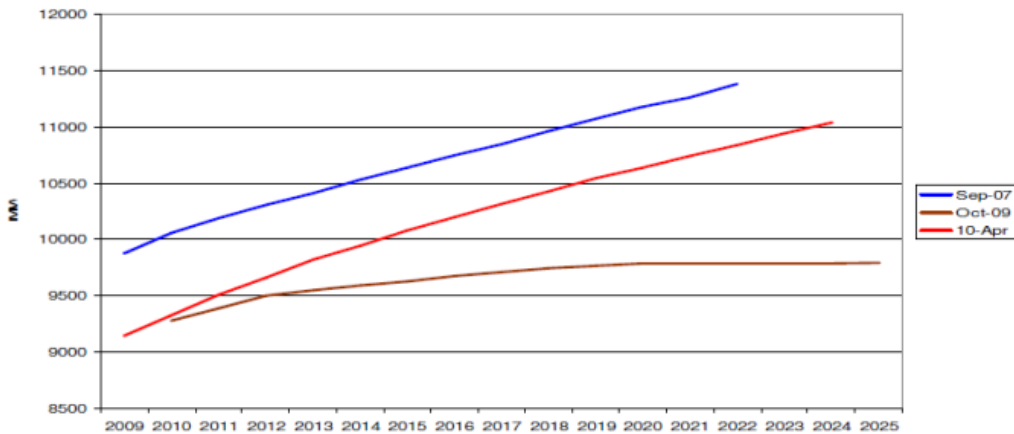
20 A. Peak demand forecasts vary as economic conditions change over time. The
21 forecast of future economic growth is one of the key measures that drives
22 growth in demand and energy. Due to the significant downturn of the
23 economy during the 2008 recession and the uncertainty in the recovery for the
24 five to six years that followed, accurately predicting economic factors along
25 with demand and energy usage has been a challenge. Attempting to predict
26 the magnitude and timing of an economic recovery has puzzled many, and has
27 also resulted in the Company having wide fluctuations in demand and energy

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1 forecasts during this time period. As a result, if actual circumstances do not
2 match the assumptions used to develop the forecast, then actual results will be
3 different than the forecasted results.

4
5 Our 2010 Resource Plan was the Company’s first Resource Plan that sought to
6 incorporate our estimates of the effect of the economic recovery from the
7 2008 recession. Figure 1.3 from our 2010 Resource Plan, below, demonstrates
8 the variability of our forecasts due to the 2008 recession and the expected
9 recovery that followed.

**Figure 1.3
Demand Forecast Over Time**



10
11 Our Spring 2010 forecast expected a stronger economic recovery than what
12 occurred. As a result, the 2010 forecast showed a rebound in need compared
13 to the 2009 forecast. By the fall of 2011, however, a more robust recovery
14 was not occurring and therefore the demand and energy need in the 2011 Fall
15 Forecast was less strong than we anticipated the previous year. While we
16 recognize that North Dakota has been experiencing growth at a faster pace
17 than the rest of the region, it has not been sufficient to offset the more

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1 sluggish recovery in the other jurisdictions served by the NSP System.

2

3 Q. HAS THE COMPANY UPDATED ITS FORECASTS SINCE THE FALL 2011
4 FORECAST?

5 A. Yes. Regularly updating our load forecasts is a normal part of our resource
6 planning efforts. Since developing our Fall 2011 Forecast, we have updated
7 our load forecast five times: in the spring of 2012, in the fall of 2012, in the
8 spring of 2013, in the fall of 2014, and in 2015.

9

10 Q. WHAT DID THESE FORECASTS UPDATES INDICATE?

11 A. In general our forecast updates since 2011 have continued to show a sluggish
12 recovery and a delay in the expected growth that we had forecast earlier. As a
13 result, the more recent updates have continued to show a slower rebound in
14 growth and a lower overall capacity need. Our 2015 Resource Plan forecast
15 indicated a capacity surplus of 313 MW in 2017 decreasing to 151 MW in
16 2019, and suggested a need of 165 MW in 2024.

17

18 Q. IS THE VARIABILITY IN THESE MORE RECENT FORECASTS UPDATES SIMILAR TO
19 THE VARIABILITY EXPERIENCED FROM 2008 TO 2011?

20 A. Yes, the variability in these subsequent updates is heavily influenced by the
21 same factors that accounted for the variability between our 2010 Resource
22 Plan forecast and our Fall 2011 Forecast. Since the recession of 2008, it has
23 been difficult to predict what kind of economic conditions will result due to
24 the uncertainty of the strength and timing of the economic recovery across the
25 region.

26

27 While the range of these more recent forecasts falls within an error band, or

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1 probability range, of only two to three percent, these changes result in varying
2 estimates of peak demand by approximately 250 MW within the 2016-2020
3 timeframe.

III. IMPLICATIONS OF NEED ASSESSMENT

4
5
6
7 Q. WHAT ARE THE IMPLICATIONS OF THE VARIABILITY OF DEMAND FORECASTS
8 OVER TIME?

9 A. The variability in our forecasts since the Fall 2011 Forecast, which established
10 our baseline resource need, indicates that the NSP System could be in deficit
11 between 2017 and 2024. And, while our most recent 2105 Resource Plan
12 forecast suggests weakening demand, this forecast also demonstrates that our
13 capacity position in 2019 and 2020 is very near a deficit. In other words, our
14 forecast updates have demonstrated a slackening of demand that could argue
15 to postpone making capacity additions. However, we believe that a
16 conservative approach to meeting our needs is appropriate at this time.

17
18 Q. PLEASE ELABORATE.

19 A. Fundamentally, this issue is related to the appropriate way to determine and
20 then meet resource needs. We could continually update our forecasts and
21 then only act when the size and timing of a need is absolutely certain. This
22 would require us to wait until very close in time for our need to develop to
23 ensure we have the certainty that there is a need to be filled. While this course
24 of action would postpone any investment until need is certain, it could
25 potentially significantly limit our options as to how to meet that need given
26 the lack of time to develop proposals and probe the market for cost effective
27 resources. Further, short term solutions such as capacity market purchases

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1 would leave us vulnerable to potentially increasing spot market pricing at the
2 exact time we would need to contract for capacity. In other words, meeting
3 the need and maintaining reliability would take precedence over cost
4 effectiveness.

5
6 On the other end of the spectrum, we could identify our needs many years out
7 and then work to meet that more uncertain need. This would give us plenty
8 of time to develop cost effective proposals and undergo all necessary
9 regulatory approvals, which can add years to the development cycle. The
10 advantages of such an approach is that the Company is in a position to be
11 flexible as to the timing of resource selection/construction, taking advantage
12 of periods when costs are lower, the market is not constrained, and financing
13 costs are possibly lower.

14
15 Ultimately, the most prudent course of action is somewhere between these
16 two extremes. It makes the most sense to move forward when a need is
17 sufficiently certain that it would make sense to add capacity to the system but
18 far enough into the future to allow the time necessary for the lengthy project
19 analysis, regulatory approval, and resource development processes.

20
21 Q. WHAT IS THE COMPANY'S RECOMMENDATION BASED ON THE VARIABILITY IN
22 THE FORECASTS OF THE COMPANY'S NEED?

23 A. Our recommended course of action is to act conservatively in the face of
24 uncertainty and make resource additions as a need is forecasted and have
25 those additions be of a size and type to address the need in a way that also
26 positions us well for the future. This approach is premised on the assumption
27 that it is better for a utility to be long than short on capacity, since the utility

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1 has the obligation to serve all of its customers’ needs under all reasonable
2 circumstances and must have resources available to meet those needs. The
3 benefits to this approach are that it provides the time needed to make resource
4 decisions through the use of competitive processes to help bring down the
5 cost of these resources. Additionally, it avoids exposing the Company - and
6 ultimately customers - to the short-term capacity markets and the price
7 uncertainty inherent with such markets. Mr. Johnson discusses further in his
8 Direct Testimony how the Calpine Project PPA in combination with the
9 Geronimo Solar PPA and Black Dog Unit 6 appropriately address our
10 customer’s need under all reasonable circumstances, specifically including the
11 softer need forecast in our 2015 Resource Plan.

12
13 Q. ARE THERE OTHER CIRCUMSTANCES THAT WOULD ALSO SUPPORT THE
14 PRUDENCE OF MAKING RESOURCE ADDITIONS TO THE SYSTEM NOW?

15 A. Yes. Determining whether to add resources to the NSP System is a fact
16 specific determination. In this instance, we identified our need almost five
17 years ago and have moved forward in the project selection and regulatory
18 approval process consistent with that identified need. While we have been
19 doing this, our updated forecasts indicate a slackening of demand which could
20 argue against making a capacity addition at this time. However, this should be
21 weighed against several other factors including: (1) anticipated MISO-wide
22 capacity retirement; (2) the currently favorable interest rate and cost
23 environment; (3) an uncertain environmental regulatory environment; and (4)
24 low capacity surplus margins.

25

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1 Q. PLEASE DESCRIBE THE IMPACT THAT Midcontinent Independent System
2 Operator, Inc., (MISO)-WIDE CAPACITY RETIREMENTS WILL LIKELY HAVE ON
3 THE PRUDENCE OF MAKING A RESOURCE ADDITION AT THIS TIME.

4 A. Our analyses indicate that the cost of generation development, especially gas
5 fired generation, may become more expensive as demand for new gas-fired
6 generation increases due to the decommissioning of several coal plants in the
7 MISO footprint. The plant retirements are also expected to increase the costs
8 of short-term capacity in MISO’s voluntary short-term capacity markets as
9 such capacity becomes more valuable as resources are constrained. This
10 argues for making resource additions now, rather than waiting.

11
12 Q. PLEASE DESCRIBE HOW THE INTEREST RATE AND COST ENVIRONMENT IMPACT
13 THE PRUDENCE OF MAKING A RESOURCE ADDITION AT THIS TIME.

14 A. As relates to cost, the Calpine Project PPA represents some of the lowest cost
15 combined cycle capacity and energy we have seen. Locking in this low cost
16 resource will help to mitigate any tightening of capacity that may occur in the
17 MISO markets.

18
19 With respect to interest rates, low rates provide less expensive financing for
20 the Company’s project. Moving forward with the Black Dog 6 Project in this
21 low-interest rate environment can lock in cheaper financing now than risk
22 more expensive financing in the future.

23
24 Q. PLEASE DESCRIBE HOW AN UNCERTAIN ENVIRONMENTAL REGULATORY
25 ENVIRONMENT SUPPORTS ADDING RESOURCE ADDITIONS AT THIS TIME.

26 A. Positioning the NSP System for an uncertain regulatory future with respect to
27 greenhouse gas and other environmental requirements through the addition of

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1 gas-fired generation and new solar makes sense given that we would secure the
2 very attractive pricing for the Calpine Project PPA and the innovative use of
3 solar as a capacity resource through the Geronimo Solar PPA. Additionally,
4 gaining experience with managing solar capacity interconnected to our
5 distribution system also provides benefits now while positioning us for the
6 increase in the use of this generation type into the future.

7
8 Q. PLEASE DESCRIBE HOW THE ANTICIPATED MARGIN OF SURPLUS CAPACITY
9 AFFECTS THE PRUDENCE OF MAKING A RESOURCE ADDITION AT THIS TIME.

10 A. Our demand forecast variability, and the small margin that we have on our
11 current system, argue to move forward with capacity additions now in case our
12 forecasts turn out to be inaccurate and the NSP System could become short.

13
14 **IV. MPUC ASSESSMENT OF NEED**

15
16 Q. DID THE FALL 2011 FORECAST UPDATE FORM THE BASIS OF REGULATORY
17 REVIEW OF THE COMPANY'S PROPOSAL IN NORTH DAKOTA AND MINNESOTA?

18 A. Yes. At the time we made our initial filing in the Minnesota Competitive
19 Acquisition Process (CAP) proceeding (Docket No. E002/CN-12-1240), the
20 Fall 2011 Forecast was the most up-to-date information available. The Fall
21 2011 Forecast formed the underlying basis for establishing need in that
22 proceeding, but as I previously noted was updated several times.

23
24 Q. DID THE COMPANY ONLY RELY UPON THE UPDATED 2011 FORECAST IN
25 PRESENTING RESOURCE OPTIONS TO THE MINNESOTA PUBLIC UTILITIES
26 COMMISSION (MPUC)?

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1 A. No. Prior to the MPUC’s May 23, 2014 Order directing the Company to
2 negotiate PPAs with Geronimo, Calpine, and Invenergy so that the MPUC
3 could determine which of these resources to approve for acquisition to meet
4 our need, we updated our forecast through September 2013. This updated
5 forecast identified a slackening of need of 117 MW in 2017, 118 MW in 2018
6 and 123 MW in 2019.

7

8 Q. DID THE MPUC AGREE WITH THIS FORECAST UPDATE?

9 A. The MPUC considered the September 2013 update as a valid data point
10 from which to consider its decision. However, the MPUC did not conclude
11 that the September 2013 update justified changing their 2010 Resource Plan
12 conclusion that the NSP System requires between 150 and 500 MW of new
13 capacity in the 2017-2019 timeframe. To the contrary, the MPUC concluded
14 that the update, when coupled with all of the other data points in the record,
15 supported taking a conservative approach to plan for up to 500 MW of new
16 capacity.

17

18 Q. DID THE COMPANY PROVIDE ANY ADDITIONAL UPDATES?

19 A. Yes. On September 23, 2014 we made a compliance filing with the
20 MPUC, presenting draft PPAs the Company negotiated with Geronimo,
21 Calpine, and Invenergy. In that filing we updated our customer demand
22 forecast, and provided information about the then-current resource
23 assessment. We believed this information suggested that our capacity need
24 had changed from an *increasing need* to a *flat capacity surplus* through as late as
25 2023. This conclusion was supported by two factors: (1) continuing flat
26 demand growth, and (2) continuing evolution of the MISO reserve margin
27 requirements which suggested we required lower reserves than we had

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1 A. While our decision to add 500 MW of capacity to the system at this time is
2 prudent, we recognize that this is based on a conservative assessment of need
3 and that the Commission could make a different policy judgment. Further, we
4 recognize that the Commission could disagree with our choice of resources to
5 meet this need. If this were to occur, we respectfully request that any resource
6 for which the Commission does not grant an ADP be included in the
7 “Restack Agreement” that the Company is currently negotiating with
8 Commission Staff.

9

10 Q. WHY WOULD IT BE APPROPRIATE TO INCLUDE A RESOURCE FOR WHICH THE
11 COMMISSION DOES NOT GRANT AN ADP IN THE RESTACK?

12 A. The Company views the Restack as a reasonable short- to mid-term tool to
13 address the continuing divergence of state energy policies and their impact on
14 the integrated NSP System, which allows us the time to find a long-term
15 mechanism to address this continuing issue. Should the Commission not
16 deem our proposal – which implements the MPUC’s recommendation in the
17 CAP Docket both as to need and the resources to meet that need – prudent,
18 we believe that utilizing the Restack methodology for these resources will
19 provide an avenue that will allow us to continue to plan and operate the NSP
20 System on an integrated basis while long-term solutions to divergent energy
21 policies are developed.

22

23 Q. HOW WILL THE RESTACK ALLOW THE COMPANY TO CONTINUE TO PLAN AND
24 OPERATE THE NSP SYSTEM ON AN INTEGRATED BASIS?

25 A. As the Commission is aware, development of the Restack Agreement is
26 guided by 10 negotiating principles adopted by the Commission in the
27 Settlement Agreement of our last rate case. Key among these principles is that

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1 any proxy pricing for restacked resources reflects both the energy and capacity
2 impacts of any new resource addition (such as those proposed by the
3 Company here) that have been rejected by the Commission. By addressing
4 both the capacity and energy impacts of new resource additions, the Restack
5 will recognize the used and useful nature of these resource additions to the
6 NSP System while mitigating the cost impact on our North Dakota customers
7 of energy policy decisions made in other states with which the Commission
8 does not concur.

9
10 The Settlement Agreement’s negotiating principles outlined that the
11 appropriate proxy pricing would reflect the marginal cost of the next unit of
12 capacity or energy available to be added to the system. We are continuing to
13 negotiate the appropriate proxy pricing for this “marginal” cost for both
14 capacity and energy with Commission Staff, which will establish the “used and
15 useful” pricing for any new resource additions subject to the Restack.

16
17 Q. WHY IS IT IMPORTANT THAT BOTH ENERGY AND CAPACITY IMPACTS BE
18 ACCOUNTED FOR IN THE RESTACK METHODOLOGY?

19 A. The Restack concept is premised on the ability to continue to plan and
20 operate the NSP System as an integrated whole while addressing the impact of
21 different state energy policies on our North Dakota customers. To meet these
22 objectives, we have proposed a methodology where a proxy price for energy
23 and capacity would replace the actual cost of the new resource addition in
24 rates. By utilizing a proxy price, the costs of the proposed new resource
25 addition can be measured against an objective standard (*i.e.* the cost of the
26 next increment of energy or capacity to the system) to determine what type of
27 “policy premium” exists for the resource addition. By accounting for capacity

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1 and energy, our North Dakota customers are still contributing to used and
2 useful resource on the integrated system and for the energy they use and the
3 capacity that is serving them.

4
5 Q. IF THE COMMISSION WERE TO DENY AN ADP FOR THE COMPANY’S PROPOSED
6 RESOURCE ADDITIONS BECAUSE IT DETERMINES THAT THERE IS NO NEED TO
7 ADD CAPACITY AT THIS TIME, BUT ALLOWS THESE RESOURCE ADDITIONS TO BE
8 INCLUDED IN THE RESTACK, WOULD NORTH DAKOTA CUSTOMERS BE PAYING
9 FOR ENERGY AND CAPACITY THAT THE COMMISSION DETERMINES IS NOT
10 NEEDED?

11 A. No. With respect to energy, as discussed in the Direct Testimony of Mr.
12 Johnson, our resource additions will likely displace the production of energy
13 from other resources on the system. Because the system must always balance
14 generation and load, all of our customers use the energy that is produced by
15 these new resource additions when they are generating.¹ Therefore, the
16 Restack is merely repricing energy that is being consumed by our North
17 Dakota customers.

18
19 Capacity, on the other hand, is additive to the system and does not displace
20 other capacity. Our resource planning efforts take into account the lumpy
21 nature of capacity additions when planning for the next capacity additions to
22 the system. By providing for capacity in the Restack Agreement, the
23 negotiating principles in our rate case Settlement Agreement recognize the
24 impact that capacity additions have on the need for and timing of the next
25 increment of capacity for the system.

¹ The Company may also sell energy to third parties. Under the Settlement Agreement in Case No. PU-12-813, we will credit back to customers 100% of the earnings on such sales.

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Q. WHY DOES CAPACITY HAVE TO BE ACCOUNTED FOR IN THE RESTACK TO MAINTAIN THE INTEGRITY OF THE INTEGRATED SYSTEM?

A. Our resource planning takes into account all accredited capacity on our system to determine the size and timing of our future capacity needs. By doing so, we account for all resources, including those added to meet other states’ energy policy goals such as solar resources, as well as traditional thermal resources. When the Company adds the capacity represented by the Calpine Project PPA and Geronimo Solar PPA, as well as Black Dog Unit 6, to the system, the size, type, and timing of any future resource additions will be affected.

In short, we plan and operate the NSP System on an integrated basis, and as a result the addition of new resources impacts our system-wide capacity needs into the future for all of the states we serve. If our North Dakota customers do not contribute to the addition of new used and useful capacity, I believe it would be inappropriate for us to allocate the new capacity to address any capacity shortfalls for our North Dakota load. Rather, the Company would seek to mitigate its inability to recover the costs of this new capacity either by reallocating it to other jurisdictions within our integrated system, or seek to sell the new capacity to a third party.

If this were to occur, we will no longer be able to manage the NSP System as an integrated whole since some capacity component of our resource additions - in this instance roughly 18 to 20 MW representing North Dakota’s allocation of the approximately 350 MW of capacity provided by the Geronimo Solar PPA and Calpine Project PPA - will not be available to the system. This will

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1 require us to plan for and manage our North Dakota load on a separate basis
2 than the remainder of the NSP System.

3
4 Q. WOULD THE OUTCOME BE THE SAME IF THE COMMISSION DENIED AN ADP
5 FOR THE COMPANY’S REQUESTED RESOURCE ADDITION AND DID NOT ALLOW
6 IT TO BE INCLUDED IN THE RESTACK.

7 A. Yes. As I mentioned, the Restack mechanism, with proxy pricing for capacity,
8 will provide short- to mid-term mitigation of the impact that different states’
9 determinations with respect to adding new capacity to our system may have
10 on our North Dakota customers while ensuring they contribute something
11 towards the used and useful capacity. We believe the Restack will provide us
12 with time to more completely address divergent energy policies. However, if
13 the Commission rejects our ADP, or if the Restack is rejected by the
14 Commission or does not account for capacity added to the system, we believe
15 that it will be challenging to continue to integrate our North Dakota
16 customers into the NSP System on a going forward basis.

17
18 Q. WILL THE COMPANY PROPOSE ANY ALTERNATIVES SHOULD THE COMMISSION
19 CHOOSE NOT TO ALLOW FOR CAPACITY PROXY PRICING FOR THOSE RESOURCES
20 FOR WHICH THERE IS NO DEMONSTRATED NEED?

21 A. We have demonstrated that our proposed resource additions are prudent and
22 respectfully request that the Commission grant our requested ADP. In the
23 alternative, we respectfully request that the Commission allow us to include
24 our resource additions in the Restack Agreement and address appropriate
25 implementation of capacity proxies as part of those negotiations. Should the
26 Commission reject our ADP and the Restack Agreement, it is incumbent

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1 upon the Company to propose solutions to the impact that divergent state
2 energy policies have on us and all of our customers.

3

4 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

5 A. Yes, it does.


STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION
OF NORTHERN STATES POWER
COMPANY FOR AN ADVANCE
DETERMINATION OF PRUDENCE FOR
A POWER PURCHASE AGREEMENT
WITH MANKATO ENERGY CENTER,
LLC FOR APPROXIMATELY 345 MW OF
COMBINED-CYCLE NATURAL GAS
GENERATION

Case No. PU-15-_____


STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Kurtis J. Haeger, being first duly sworn on oath, deposes and says that he is the Managing Director of Resource Planning for Xcel Energy Services Inc., the service company subsidiary of Xcel Energy, in the above captioned matter, that he has read the testimony and schedules submitted in the above captioned matter under his name, that they were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.



Kurtis J. Haeger

Subscribed and sworn to before me this 15th day of February, 2015.



Notary Public
My Commission Expires: 9/28/16

YRENE A NUÑEZ
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 19874149394
MY COMMISSION EXPIRES SEPTEMBER 28, 2016

Kurtis J. Haeger

Statement of Qualifications

I graduated from the University of Colorado, Boulder, in 1982 with a Bachelor of Science Degree in Civil Engineering and from the University of Colorado, Denver, in 1987, with a Master of Business Administration in Finance.

I began my employment with Public Service Company of Colorado in June 1982, as a Gas Distribution Engineer. In June 1988, I was promoted to Supervisor, Gas Utilization and Testing. In May 1990, I was promoted to System Planning & Forecasting Manager, and, in October 1994, I was promoted to Gas Supply and Planning Manager. Upon the merger between Public Service Company of Colorado and Southwestern Public Service Company in August 1997, I assumed the same position with New Century Services, Inc., the service company subsidiary of New Century Energies, Inc. In March 1999, I assumed the position of Director, Gas Business Support. Upon the merger between New Century Energies, Inc. and Northern States Power Company in August 2000, I was appointed to the position of Director, Gas Supply and Supply Planning for Xcel Energy Services Inc. In May 2004, I was promoted to the position of Managing Director, Resource Planning, the position I currently hold.

Since 1990, my responsibilities have included the development of forecasts of annual and daily gas requirements, long term price of gas forecasts, cost of gas budgets, business planning, strategic planning, long range gas supply planning and gas integrated resource planning, gas supply purchasing, the purchasing of gas transportation and storage services and electric resource planning for Public Service Company, Northern States Power Company and Southwestern Public Service. In my present position, I am

responsible for the resource planning and for the acquisition and bidding activities for electric generation on all of our electric systems.

I have presented testimony before the Colorado Public Utilities Commission in Docket Nos. 93A-561G, 94A-447G, 93S-001EG (95I-394G), 02A-267G, 98S-518G, 00A-415G, 97A-622G, 99A-549E, 00A-415G, 01A-181E, 02A-267G, 02S-315EG, 02A-541E, 03A-489EG and Application No. 34815. I have also sponsored testimony before the Federal Energy Regulatory Commission in Colorado Interstate Gas Co.'s rate case Docket Nos. RP93-99 and RP96-190, Northern Natural Gas Co.'s rate case Docket No. RP03-398 and before the Wyoming Public Service Commission, the North Dakota Commission, the Minnesota Commission and the Texas Commission in various electric and rate case proceedings.

POWER PURCHASE AGREEMENT

BETWEEN

**NORTHERN STATES POWER COMPANY, A MINNESOTA
CORPORATION
("COMPANY")**

AND

**MANKATO ENERGY CENTER II, LLC, A DELAWARE
LIMITED LIABILITY COMPANY
("SELLER")**



- [date] -

Table of Contents

	Page
Article 1 - Rules of Interpretation	1
1.1 Interpretation.....	1
1.2 Interpretation with Other Agreements.	2
1.3 Good Faith and Fair Dealing.....	2
1.4 Waiver.....	2
Article 2 - Term and Termination.....	3
2.1 Term.	3
2.2 Governing PPA.	3
2.3 Delay.....	3
2.4 Early Termination.....	4
2.5 Limited Liability for Costs for Delay and Early Termination.....	5
2.6 Audit.....	5
Article 3 - Facility Description	5
3.1 Description.....	5
3.2 General Design of the Facility.....	5
Article 4 - Implementation.....	6
4.1 Project Development.....	6
4.2 Commercial Operation.....	7
4.3 COD Conditions.....	7
4.4 Test Energy.	9
Article 5 - Delivery	10
5.1 Electric Delivery Arrangements.....	10
5.2 Electric Metering Devices.	11
5.3 Fuel.....	12
Article 6 - Conditions Precedent.....	14
6.1 Company CPs.....	14
6.2 Seller CPs.....	15
Article 7 - Sale and Purchase.....	16
7.1 General Obligation.....	16
7.2 Capacity and Energy.....	16

Table of Contents
(continued)

	Page
7.3 Alternate Generation Sources.....	16
7.4 Dispatch.....	17
7.5 Other Products and Services.....	18
Article 8 - Payment Calculations	19
8.1 Capacity Payments.....	19
8.2 Payment for Dispatchability.....	23
8.3 Payment for Energy.....	25
8.4 Heat Rate Adjustment to Payments.....	25
8.5 Heat Rate Testing.....	26
8.6 Payment for Turbine Starts.....	29
8.7 ESC Event Adjustment.....	29
Article 9 - Billing and Payment	30
9.1 Billing Invoices.....	30
9.2 Payment.....	30
9.3 Billing Disputes.....	31
Article 10 - Operations and Maintenance	31
10.1 Operation and Administration.....	31
10.2 Facility Maintenance.....	32
10.3 Books and Records.....	33
10.4 Operating Committee and Operating Procedures.....	34
10.5 Access to Facility.....	35
10.6 Accreditation.....	35
Article 11 - Security for Performance.....	38
11.1 Security Fund.....	38
11.2 Subordinated Mortgage.....	42
Article 12 - Default and Remedies.....	43
12.1 Events of Default.....	43
12.2 Remedies.....	44
12.3 Limitation on Damages.....	46
12.4 Step-In Rights.....	47

Table of Contents
(continued)

	Page
12.5 Duty to Mitigate.....	49
Article 13 - Dispute Resolution.....	49
13.1 Dispute Resolution.....	49
Article 14 - Force Majeure.....	50
14.1 Applicability of Force Majeure.....	50
14.2 Limitations on Effect of Force Majeure.....	50
14.3 Delays Attributable to Company.....	50
Article 15 - Representations and Warranties.....	51
15.1 General Representations and Warranties.....	51
15.2 Seller's Specific Representation.....	52
15.3 Company's Specific Representation.....	52
Article 16 - Insurance.....	53
16.1 Evidence of Insurance.....	53
16.2 Term and Modification of Insurance.....	53
16.3 Application of Proceeds.....	54
Article 17 - Indemnity.....	54
17.1 Indemnification.....	54
17.2 Notice of Claim.....	54
17.3 Settlement of Claim.....	54
17.4 Amounts Owed.....	55
Article 18 - Lender Provisions.....	55
18.1 Accommodation of Facility Lender.....	55
18.2 Facility Lender Notice and Right to Cure.....	55
18.3 Notice of Facility Lender Action.....	55
18.4 Officer Certificates.....	55
Article 19 - Assignment and Other Transfer Restrictions.....	56
19.1 Transfer Without Consent is Null and Void.....	56
19.2 ROFO.....	57
19.3 Subcontracting.....	58
Article 20 - Miscellaneous.....	58

Table of Contents
(continued)

	Page
20.1 Notices.....	58
20.2 Taxes, Emissions and Change of Law.....	58
20.3 Applicable Laws.....	60
20.4 Fines and Penalties.....	60
20.5 Rate Changes.....	60
20.6 Disclaimer of Third Party Beneficiary Rights.....	61
20.7 Relationship of the Parties.....	61
20.8 Equal Employment Opportunity Compliance Certification.....	61
20.9 Survival of Obligations.....	61
20.10 Severability.....	62
20.11 Complete Agreement; Amendments.....	62
20.12 Binding Effect.....	62
20.13 Headings.....	62
20.14 Counterparts.....	62
20.15 Governing Law.....	62
20.16 Press Releases and Media Contact.....	62
20.17 Exhibits.....	62
20.18 Confidentiality.....	63
EXHIBIT A	DEFINITIONS
EXHIBIT B	CONSTRUCTION MILESTONES
EXHIBIT C	FACILITY DESCRIPTION, ONE-LINE DIAGRAM, AND SITE MAP
EXHIBIT D	NOTICES AND CONTACT INFORMATION
EXHIBIT E	INSURANCE COVERAGE
EXHIBIT F	MATERIAL PERMITS
EXHIBIT G	FORM OF SECURITY DOCUMENTS
EXHIBIT H	OPERATING STANDARDS
EXHIBIT I	LENDER CONSENT PROVISIONS
EXHIBIT J	PREDICTED NET HEAT RATE DEGRADATION ADJUSTMENT
EXHIBIT K	FUEL QUALITY SPECIFICATIONS
EXHIBIT L	MAINTENANCE REQUIREMENTS
EXHIBIT M	ESC EVENT ADJUSTMENT
EXHIBIT N	FACILITY OPERATIONAL INFORMATION

**Power Purchase Agreement,
between
MANKATO ENERGY CENTER II, LLC, A DELAWARE LIMITED LIABILITY COMPANY,
AND
NORTHERN STATES POWER COMPANY, A MINNESOTA
CORPORATION**

This Power Purchase Agreement (this “PPA”) is made this [____] day of [____], 20__ (the “Effective Date”), by and between (i) Northern States Power Company, a Minnesota corporation with a principal place of business at 414 Nicollet Mall, Minneapolis, Minnesota, 55401, (“Company”), (ii) Mankato Energy Center II, LLC, a Delaware limited liability company with offices at 717 Texas Avenue, Suite 1000, Houston, TX 77002 (“Seller”), and, with respect to Section 2.2 and Section 19.2 only, Mankato Energy Center, LLC, a Delaware limited liability company with offices at 717 Texas Avenue, Suite 1000, Houston, TX 77002 (“MEC I”). Company and Seller are hereinafter sometimes referred to individually as a “Party” and collectively as the “Parties”.

WHEREAS, Seller desires to develop, design, construct, interconnect, own, operate and maintain the Facility as defined herein; and

WHEREAS, Seller desires to sell and deliver and Company desires to accept and receive certain products and services delivered from the Facility to the Point of Delivery at the prices and on the terms and conditions set forth in this PPA.

NOW THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following:

Article 1 - Rules of Interpretation

1.1 Interpretation.

(A) Capitalized terms listed in this PPA shall have the meanings set forth in Exhibit A-Definitions or as otherwise defined in this PPA, whether in the singular or the plural or in the present or past tense. Words not otherwise defined in this PPA shall (i) have meanings as commonly used in the English language, (ii) be given their generally accepted meanings consistent with Good Utility Practice, and (iii) be given their well known and generally accepted technical or trade meanings.

(B) The following rules of interpretation shall apply: (1) the masculine shall include the feminine and neuter; (2) references to “Articles,” “Sections,” or “Exhibits” shall be to articles, sections, or exhibits of this PPA except as the context may otherwise require; (3) all Exhibits are incorporated into this PPA; *provided, however, that* in the event of a conflict with the terms of this PPA, the PPA shall

control; and (4) use of the words “include” or “including” or similar words shall be interpreted as “include without limitation” or “including, without limitation.”

(C) This PPA was negotiated and prepared by both Parties with the advice and participation of counsel. The Parties have agreed to the wording of this PPA and none of the provisions hereof shall be construed against one Party on the ground that such Party is the author of this PPA or any part hereof.

1.2 Interpretation with Other Agreements.

(A) This PPA does not provide Seller authorization to interconnect the Facility or inject power into the electric delivery system. Seller shall contract for interconnection services in accordance with the applicable Transmission Tariff. Seller acknowledges that any Interconnection Agreement Seller enters into is a separate contract and that (i) this PPA is not binding on the Transmission Authority, (ii) this PPA does not create any rights between Seller and the Transmission Authority, and (iii) the Interconnection Agreement does not modify the Parties’ rights and obligations under this PPA. Seller agrees that any applicable Transmission Authority shall be deemed to be a separate and unaffiliated contracting party regardless whether such Transmission Authority is Company or an Affiliate of Company.

(B) This PPA does not provide for the supply of House Power. Seller shall contract with the Local Provider for the supply of House Power to the Facility. Seller acknowledges that obtaining House Power is a separate contract and that (i) this PPA is not binding on the Local Provider, (ii) this PPA does not create any rights between Seller and the Local Provider, and (iii) the House Power contract does not modify the Parties’ rights and obligations under this PPA. Seller agrees that the Local Provider shall be deemed to be a separate and unaffiliated contracting party regardless whether the Local Provider is Company or an Affiliate of Company. To the extent allowed by Applicable Law, Seller shall obtain House Power for the Facility by self-generating and netting such self-generation from the Energy provided to Company, *provided, however, that* such netting shall not reduce Seller’s obligation to provide Contract Energy in the amounts and during the times called for by this PPA, and *provided further that*, if Applicable Law does not allow netting of House Power, Seller shall obtain House Power for the Facility exclusively from the Local Provider.

1.3 Good Faith and Fair Dealing. The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this PPA. Unless expressly provided otherwise in this PPA, (a) when this PPA requires the consent, approval, or similar action by a Party, such consent or approval shall not be unreasonably withheld, conditioned or delayed, and (b) wherever this PPA gives a Party a right to determine, require, specify or take similar action with respect to a matter, such determination, requirement, specification or similar action shall be Commercially Reasonable.

1.4 Waiver. The failure of either Party to enforce or insist upon compliance with or strict performance of any of the terms or conditions of this PPA, or

to take advantage of any of its rights hereunder, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect.

Article 2 - Term and Termination

2.1 Term. This PPA shall become effective as of the date of its execution, and shall remain in full force and effect until the Scheduled Termination Date, subject to delay or early termination as provided in this PPA. Applicable provisions of this PPA shall continue in effect after termination to the extent necessary to (i) provide for final billings, payments and adjustments, (ii) enforce or complete the duties, obligations or responsibilities of the Parties, and (iii) address any remedies or indemnification obligations, arising prior to termination.

2.2 Governing PPA. The Parties and MEC I agree that, notwithstanding any other provision in this PPA and the March 11, 2004 Purchased Power Agreement between Company and MEC I, as amended from time to time (the "MEC I PPA") (i) this PPA alone determines and governs the rights and obligations of the Parties and MEC I with respect to the Facility; (ii) except as expressly provided in this Section 2.2 and Section 19.2, the MEC I PPA alone determines and governs the rights and obligations of MEC I and Company with respect to the MEC I Facility; (iii) except as expressly provided in this Section 2.2 and Section 19.2, in no event shall the rights, benefits and obligations of MEC I or Company as set forth in the MEC I PPA in any way be affected, modified, curtailed, restricted or otherwise limited by this PPA and, for the avoidance of doubt, in no event shall any action or failure to act by MEC I that (A) is otherwise in compliance with the MEC I PPA and (B) proximately causes Seller not to be in compliance with this PPA, be construed as an Event of Default of Seller under this PPA; and (iv) in no event shall the rights, benefits and obligations of Seller or Company as set forth in this PPA in any way be affected, modified, curtailed, restricted or otherwise limited by the MEC I PPA, and, for the avoidance of doubt, in no event shall any action or failure to act by Seller that (A) is otherwise in compliance with this PPA and (B) proximately causes MEC I not to be in compliance with the MEC I PPA, be construed as an event of default or the equivalent thereof under the MEC I PPA. The Parties and MEC I further agree that upon execution of this PPA (i) any terms and conditions in the MEC I PPA referring to or regarding the Facility shall be null and void and have no effect on this PPA and (ii) except as expressly provided in this Section 2.2 and Section 19.2 any terms and conditions in this PPA referring to or regarding the MEC I Facility shall be null and void and have no effect on the MEC I PPA. To the extent reasonably practicable, the Parties and MEC I shall interpret the MEC I PPA and this PPA harmoniously.

2.3 Delay. Company may, at its option, delay the COD of the Facility to June 1, 2019 (the "Delay Period") upon delivery of Notice of such delay to Seller on or before January 1, 2016 (the "Delay Option"). Company shall reimburse Seller for Demobilization Costs and Re-mobilization Costs incurred by Seller to accommodate Company's exercise of the Delay Option under this Section 2.3. The Parties shall revise Exhibit B-Construction Milestones to this PPA to extend the Commercial

Operation Milestone and other Construction Milestones to reflect the impacts of any delay of the COD of the Facility pursuant to this Section 2.3.

(A) Subject to the maximum capped cost of **[Trade Secret Data Begins... ...Trade Secret Data Ends]** Demobilization Costs shall, subject to audit, include such activities and costs for disassembly, removal, transportation, storage or protection of equipment and supplies (and applicable labor of personnel associated therewith) which were delivered to the Facility Site in furtherance of and in performance of this PPA and which are not required for PPA performance during the Delay Period and/or which are required to be protected during the Delay Period.

(B) Subject to the maximum capped cost of **[Trade Secret Data Begins... ...Trade Secret Data Ends]** Remobilization Costs shall, subject to audit, include such activities and associated costs for transportation of equipment and supplies (and applicable labor of personnel associated therewith) to the Facility Site which were earlier contractually required to be on the Facility site but which were suspended as a direct result of Company's exercise of the Delay Option and for which Seller has incurred costs. Remobilization Costs may also include related job site costs and equipment standby costs.

2.4 Early Termination. Company has an option to terminate this PPA for its convenience ("Early Termination") by providing Notice to Seller on or before January 1, 2016; *provided, however, that* in the event Company elects to delay the deadline for State Regulatory Approval as provided in Section 6.1(B), Company may provide the Notice of Early Termination to Seller on or before **[Trade Secret Data Begins... ...Trade Secret Data Ends]**.

(A) Subject to Section 2.6, Company shall pay to Seller the maximum capped sum of **[Trade Secret Data Begins... ...Trade Secret Data Ends]** which shall constitute Seller's Unrecovered Costs for Early Termination, no later than sixty (60) Days after receipt of Seller's invoice for such costs. Said payment of Seller's Unrecovered Costs shall constitute full and complete compensation to Seller for (without duplication of any items): (i) work performed and expenses sustained in furtherance of and in support of this PPA, in accordance with the PPA, prior to the effective date of termination, including fair and reasonable sums for overhead and profit on such work and expenses; (ii) all claims, costs, losses, and damages (including but not limited to all fees and charges of material and equipment suppliers, engineers, architects, attorneys, and other professionals and all court or arbitration or other dispute resolution costs) incurred in settlement of terminated contracts with contractors, subcontractors, suppliers, consultants, and others; and (iii) reasonable expenses directly attributable to termination.

(B) Company shall also pay to Seller a Breakage Fee **[Trade Secret Data Begins... ...Trade Secret Data Ends]** for Early Termination, which Company shall pay no later than sixty (60) Days after receipt of Seller's invoice for such fee. Payment of the Breakage Fee shall constitute full and complete

compensation to Seller (without duplication of any items) on account of loss of anticipated profits or revenue or other economic loss arising out of or resulting from such termination.

2.5 Limited Liability for Costs for Delay and Early Termination. The Parties agree that the amounts to be paid by Company to Seller for the exercise of the Delay Option or Early Termination by Company shall constitute compensation in full for such delay or termination, as applicable, including labor, equipment and materials attributable to Seller's contractors, subcontractors and suppliers, for all costs, damages, charges, and fees of whatever kind and nature directly or indirectly attributable to the exercise of the Delay Option or Early Termination. Markups (including without limitation overhead, general and administrative and profit) of Seller shall not be compensated by the Company for any delay in COD due to the exercise by Company of the Delay Option. Company will not be liable for costs which Seller could have avoided by Commercially Reasonable means, such as Commercially Reasonable handling of labor/personnel, materials, or equipment. Subject to Company's payment to Seller of any undisputed amounts due under Sections 2.3, 2.4, and 2.6, Seller shall indemnify and hold Company harmless from any demands, claims, costs and fees, including counsel fees, associated with mechanic's liens, stop notices, bonds, claims, and lawsuits and any other actions from Seller's contractors, subcontractors, consultants, and suppliers relating to the exercise by Company of the Delay Option or Early Termination; *provided, however, that* Company shall be released and held harmless from all such claims and actions before Company pays Seller.

2.6 Audit. Upon notice, Company shall have the right to audit at its own expense Seller's documentation of Demobilization Costs, Re-mobilization Costs, and Unrecovered Costs for Early Termination invoiced to Company as provided in Section 2.3 and Section 2.4 prior to payment by Company. Seller shall provide cooperation reasonably requested by Company in connection with any such audit. Company shall complete such audit within four (4) months following delivery of Company's notice of audit to Seller. Any resulting dispute shall be subject to Sections 9.3 and 13.1 of this PPA.

Article 3 - Facility Description

3.1 Description. Seller shall construct, interconnect, own, operate, and maintain the Facility, as further described in Exhibit C-Facility Description, One-Line Diagram, And Site Map. A scaled map that identifies the Site, the location of the Facility, Interconnection Point, Interconnection Facilities, the Point of Delivery, the Fuel Delivery Point, and other important facilities, is included in Exhibit C-Facility Description, One-Line Diagram, And Site Map.

3.2 General Design of the Facility.

(A) Seller shall design, construct, operate and maintain the Facility according to Good Utility Practice(s) and the Interconnection Agreement.

(B) The Facility shall include all equipment necessary to successfully interconnect with the Transmission Authority's System for the delivery of the Facility's output to the Point of Delivery.

(C) The Facility shall include all equipment and telecommunications capabilities necessary to communicate with Company's SCADA System.

(D) The Facility shall include all equipment specified in Exhibit C-Facility Description, One-Line Diagram, And Site Map or otherwise necessary to fulfill Seller's obligations under this PPA.

Article 4 - Implementation

4.1 Project Development.

(A) Seller represents and warrants that: (i) Seller has provided to Company copies of all environmental assessments performed for the Site by or on behalf of Seller or any of its Affiliates ("Environmental Assessments"), including the Wenck Environmental Assessments; (ii) Seller has no knowledge of any Environmental Contamination at the Site that is not disclosed in such Environmental Assessments; and (iii) the Site remains appropriate for its intended use by Seller. Seller shall provide Company with all future Environmental Assessments relating to or affecting the Facility or Facility Property, and Seller shall promptly inform Company if, due to any Environmental Contamination, Seller is constrained in a way that will limit, reduce, interfere with or preclude Seller's ability to perform its obligations under this PPA, along with a statement of whether and to what extent this circumstance may limit or preclude Seller's ability to perform under this PPA. Seller shall provide Company with written recommendations to overcome any such issue(s) to allow Seller to fully perform under this PPA. Upon request, Seller shall provide Company a copy of any backup data associated with the Environmental Assessments. Throughout the Term, Seller shall ensure that any Environmental Contamination identified at the Facility or Site is promptly remediated. Seller shall promptly disclose to Company the presence of any such Environmental Contamination or the existence of any enforcement, legal, or regulatory action or proceeding relating to such alleged violation or alleged presence of Environmental Contamination.

(B) Seller shall at its own expense enter the Construction Contract and all other major contracts necessary for the development, construction, operation of the Facility and delivery of products and services contemplated hereunder from the Facility with qualified and experienced contractors.

(C) Prior to the Commercial Operation Date, Seller shall (i) submit quarterly progress reports to Company in a form agreed upon by the Parties advising Company of the current status of each Construction Milestone, any significant developments or delays along with an action plan for making up delays, and Seller's best estimate of the Commercial Operation Date; and (ii) provide copies of reports

submitted to the Facility Lender relating to status, progress and development of the Facility.

(D) Upon request, Company shall have the right to monitor at the Site the construction, start-up, testing, and operation of the Facility for compliance with this PPA, *provided, however, that* Company shall comply with all of Seller's applicable safety and health rules and requirements. Company's monitoring of the Facility shall not be construed as inspections of or as endorsing the design thereof nor as any express or implied warranties relating to performance, safety, durability, or reliability of the Facility.

(E) Seller shall obtain and pay for all Permits necessary for the construction, ownership, operation and maintenance of the Facility and the generation and delivery of any output from the Facility to Company. Seller shall keep Company informed as to the status of its permitting efforts. Seller shall promptly inform Company of any Permits that Seller is unable to obtain or that are delayed, limited, suspended, terminated or otherwise constrained in a way, that will limit, reduce, interfere with or preclude Seller's ability to perform its obligations under this PPA, along with a statement of whether and to what extent such circumstance may limit or preclude Seller's ability to perform under this PPA. Seller shall provide Company with written recommendations to overcome any such issue(s) with any Permits to allow Seller to fully perform under this PPA. Seller shall provide Company copies of its Permit applications and Permits as such applications are filed and such Permits are received by Seller.

(F) Seller shall notify Company (i) sufficiently in advance of any known upcoming significant inspections by any Governmental Authority relating to the Facility to allow Company the opportunity to attend, and (ii) promptly after any unscheduled or impromptu inspection, which notification, in the case of any impromptu inspection, shall include a description of the nature and outcome of such impromptu inspection.

4.2 Commercial Operation. Subject to any extension as authorized in this PPA, the Facility shall achieve Commercial Operation no later than the Day after the Commercial Operation Milestone; *provided, however, that* Seller shall not be obligated to establish a Commercial Operation Date that is earlier than the Day after the Commercial Operation Milestone and Company shall not be obligated to accept a Commercial Operation Date that is earlier than the Day after the Commercial Operation Milestone.

4.3 COD Conditions. Subject to Section 10.6, Seller shall provide Company a Notice of the date Seller believes the Facility has achieved Commercial Operation along with all supporting documentation of the satisfaction or occurrence of all COD Conditions. Company shall have up to 10 Business Days to review such evidence and raise any Commercially Reasonable objection to Seller's satisfaction of any of the COD Conditions, *provided, however, that* such Notice shall be deemed accepted by Company if Company fails to object within such time period. At Seller's option, Seller may provide Notice of completion of the COD Conditions on an

individual and/or incremental basis, including (i) by providing more than one (1) written confirmation from an officer of Seller as required under Section 4.3(A) so as to allow Seller to confirm completion of a subset of such items and/or (ii) pending resolution of any objections, *provided, however, that* Company shall in all cases have up to 10 Business Days to review and object to each Notice. The COD Conditions are:

(A) an officer of Seller, authorized to bind Seller and who is familiar with the Facility, has provided written confirmation that (1) all Material Permits have been obtained and are in full force and effect, (2) Seller is in compliance with this PPA in all material respects; (3) the Facility is available to commence normal operations; (4) Seller is obligated under and in material compliance with the Interconnection Agreement, (5) all conditions of the Interconnection Agreement to obtain either NRIS or ERIS as applicable to the Seller have been completed; (6) all Network Upgrades required for NITS have been completed; (7) the Facility is fully interconnected to the Transmission Authority's System, has been fully tested, has achieved initial synchronization, and has been successfully operated at a generation level acceptable to the Transmission Authority, without experiencing any abnormal or unsafe operating conditions on any interconnected system, (8) Seller has completed any testing of the Facility and Interconnection Facilities required by the Interconnection Agreement; (9) Seller has met all Transmission Authority requirements for the Facility to be qualified as a Capacity Resource for the Planning Year of COD; (10) Seller has made all other arrangements necessary to deliver the output of the Facility to the Point of Delivery; (11) Seller has demonstrated (i) the reliability of the Facility's communications systems and communication interface with Company's Energy Markets Control Center ("EMCC") and the Facility is capable of receiving and reacting to signals from Company's SCADA System, and (ii) all Automatic Generation Control ("AGC") equipment is installed and operational; (12) the Facility has achieved three Successful Starts in combined cycle configuration without experiencing any abnormal operating conditions; (13) the Facility has generated in each possible combined-cycle operating configuration of the Facility while synchronized to Transmission Authority's System at full capacity without experiencing any abnormal operating conditions; (14) the Facility has generated continuously for a period of not less than 16 hours while synchronized to Transmission Authority's System at a net capacity output, adjusted to Reference Conditions, of at least 90% of the Net Capability without experiencing any abnormal operating conditions; (15) the Facility has demonstrated initial dispatchability capability, operational compliance capability, and verification of ramp range and ramp rate pursuant to Exhibit H-Operating Standards; (16) all natural gas interconnection and metering arrangements necessary to operate the Facility in compliance with this PPA have been completed, tested and are in effect; and (17) Seller has provided to Company copies of all Environmental Assessments performed for the Site by or on behalf of Seller or any of its Affiliates; and

(B) Seller has provided Company an independent registered professional engineer's certification that the Facility has been completed in all material respects, except for punch list items that do not have a Material Adverse Effect on the ability of the Facility to operate for its intended purpose; and

(C) Seller has provided written confirmation that it has the right and access to use all the electric generating facilities and associated balance of plant, parts, equipment, and property necessary to operate and maintain the Facility in accordance with the terms of this PPA.

4.4 Test Energy.

(A) Pre-COD Test Energy. Seller shall be responsible for providing the necessary information to, and making all arrangements with, the Transmission Authority and any third parties to the extent required in advance and for the purposes of generating any pre-COD Test Energy, including, as applicable, the information necessary to have the Facility registered with the Transmission Authority for inclusion in any generation modeling maintained by the Transmission Authority, to allow the Facility to be registered in such model sufficiently in advance of generating any pre-COD Test Energy in accordance with the Transmission Authority's requirements.

1. Prior to the COD, Seller shall coordinate with Company the production and delivery of any Test Energy, and any other energy produced by the Facility that Company is required to purchase pursuant to Section 4.4(A)4, with not less than six (6) Days Notice to Company, subject to any changes as Seller may reasonably request no later than 24 hours prior to such production and delivery or as required by Good Utility Practices. The Parties shall cooperate to facilitate Seller's testing of the Facility necessary to satisfy the COD Conditions. Company shall pay the Test Energy Rate for all Test Energy delivered prior to COD and energy Company is required to purchase pursuant to Section 4.4(A)4.

2. Seller shall reimburse Company for the cost of fuel used for such Test Energy, which shall be calculated as the volume of natural gas consumed to generate the Test Energy multiplied by the Daily Gas Cost.

3. Company shall pay Seller for Test Energy at the Test Energy Rate. Company shall have no obligation to make any other payments to Seller pursuant to Article 8 in connection with the purchase of such Test Energy.

4. Prior to the Delivery and Supply Commencement Notice Effective Date under Section 10.6(B), Seller shall have the right to sell energy and/or capacity from the Facility to third parties; *provided, however, that* Company shall not provide fuel for such sales; *and provided further that* such sales do not adversely affect, modify, curtail, restrict or otherwise limit the availability or operation of the MEC I Facility pursuant to the MEC I PPA. For avoidance of doubt, Seller shall not have the right to sell energy or capacity from the Facility to third parties on or after the Delivery and Supply Commencement Notice Effective Date. After the Delivery and Supply Commencement Notice Effective Date but prior to COD, Company shall purchase all energy produced by the Facility and delivered to the Company at the Point of Delivery.

(B) Post-COD Test Energy. After COD, to the extent practicable, Seller shall conduct all necessary testing of the Facility when Company is otherwise dispatching the Facility and post-COD Test Energy generated and delivered during such tests shall be treated as Contract Energy for all purposes. If Seller must conduct tests when the Facility would not otherwise be dispatched: (i) Company shall pay to Seller the Test Energy Rate; (ii) any restrictions in the amount of available Contract Capacity due to such testing shall be reflected in the monthly Capacity Payment specified in Section 8.1; and (iii) Seller shall reimburse Company for the cost of fuel used for such post-COD Test Energy, which cost shall be volume of natural gas consumed to generate the Test Energy multiplied by the Daily Gas Cost.

Article 5 - Delivery

5.1 Electric Delivery Arrangements.

(A) Seller shall be responsible for making, maintaining, and paying all costs associated with the interconnection of the Facility to the Transmission Authority's System. Company shall reimburse Seller for Seller's Reimbursable Transmission Costs. Upon the Parties' concurrence that Seller has met the requirements of Section 4.3, Seller shall provide an invoice to Company with appropriate detailed support that documents Seller's Reimbursable Transmission Costs. Notwithstanding anything to the contrary in this PPA, Company shall reimburse Seller for Seller's Reimbursable Transmission Costs within thirty (30) days from receipt of invoice. Seller shall comply with the Transmission Authority's requirements for the interconnection and shall comply with all requirements set forth in the applicable Transmission Tariff. The Point of Delivery shall be located in what the Transmission Authority currently designates as Local Resource Zone 1.

1. Seller shall obtain either (i) NRIS or (ii) ERIS. In the event Seller interconnects as an ERIS and without limiting Company's obligation to reimburse Seller for Seller's Reimbursable Transmission Costs, Seller shall be responsible for paying Company for any Network Upgrades costs associated with the Company obtaining firm Network Integration Transmission Service ("NITS") from the Point of Delivery to Company load and Company shall reimburse Seller for any such costs to the extent not already included in Seller's Reimbursable Transmission Costs within thirty (30) days of receipt of an invoice with appropriate detailed support. For either NRIS or ERIS all conditions of the Interconnection Agreement and any identified Network Upgrades associated with NITS must be satisfied by the Commercial Operation Date and the generation output must qualify as a Capacity Resource.

(B) Seller authorizes Company to contact and obtain information concerning the Facility and Interconnection Facilities directly from any applicable Transmission Authority and, upon request, Seller shall confirm such authorization in writing to such Transmission Authority or any applicable transmission owners in such form as requested by Company or the Transmission Authority.

(C) Seller shall be responsible for all interconnection, electric losses, transmission and ancillary service arrangements and costs required to deliver, on a firm transmission service basis, the output from the Facility to the Point of Delivery.

(D) Company shall be responsible for delivering the Facility's output beyond the Point of Delivery. If at any time during the Term, the entity owning the transmission facilities at the Point of Delivery changes or the facilities at the Point of Delivery cease to be subject to the Transmission Tariff, then the Parties shall cooperate in good faith to amend this PPA in a manner to facilitate the delivery of output from the Point of Delivery to Company's customers at the least possible cost to Company and Seller.

5.2 Electric Metering Devices.

(A) All Electric Metering Devices used to measure energy from the Facility shall be provided by Company to Seller for installation and owned and maintained by Company in accordance with the Interconnection Agreement.

1. For purposes of this PPA, meter readings will be adjusted to reflect losses from the Electric Metering Devices to the Point of Delivery based initially on the amount specified by the manufacturer for expected losses, *provided, however, that* the Operating Committee may revise this loss adjustment based on actual experience.

2. Company shall provide Seller the opportunity to be present at any time when such Electric Metering Devices are to be inspected and tested or adjusted.

(B) Either Party may elect to install and maintain, at its own expense, backup metering devices ("Back-Up Metering"), *provided, however, that* the specifications, installation and testing of any such Back-Up Metering shall be consistent with the requirements for the Electric Metering Devices. Upon written request, the installing Party shall conduct retests requested by the other Party. The actual cost of any retest shall be borne by the Party requesting the test, unless, upon such retest, Back-Up Metering is inaccurate by more than one percent, in which case the cost of the retest shall be borne by the installing Party. If requested in writing, the installing Party shall provide copies of any inspection or testing reports to the requesting Party.

(C) If an Electric Metering Device or Back-Up Metering, fails to register, or if the measurement is inaccurate by more than one percent, an adjustment shall be made correcting all measurements as follows:

1. If the Electric Metering Device is found to be defective or inaccurate, the Parties shall use Back-up Metering, if installed, to determine the amount of such inaccuracy, *provided, however, that* Back-Up Metering has been tested and maintained and adjusted for losses on the same basis as the Electric Metering Device. If Back-Up Metering is not installed, or Back-Up Metering is also

found to be inaccurate by more than one percent, the Parties shall use the best available information for the period of inaccuracy, adjusted as agreed by the Parties for losses to the Point of Delivery.

2. If the Parties cannot agree on the actual period during which the inaccurate measurements were made, the period shall be the shorter of (i) the last one-half of the period from the last previous test of the Electric Metering Device to the test that found the Electric Metering Device to be defective or inaccurate, or (ii) 180 Days immediately preceding the test that found the Electric Metering Device to be defective or inaccurate.

3. To the extent that the adjustment period covers a period of deliveries for which payment has already been made by Company, Company shall use the corrected measurements as determined in accordance with this Article to recompute the amount due for the period of the inaccuracy and shall subtract the previous payments made by Company for this period from such re-computed amount. The net difference shall be reflected as an adjustment on the next regular bill in accordance with Article 9.

5.3 Fuel.

(A) All fuel for the Facility from and after the COD shall be procured and paid for by Company and shall be delivered to the Facility pursuant to this Section at a pressure not less than 550 psig at the Fuel Delivery Point. Title to the fuel shall be retained by Company at and from the Fuel Delivery Point to the burner tips of the Facility. As between the Parties, however, Seller shall be deemed to be in exclusive control and possession of all such fuel after the Fuel Delivery Point and Seller shall bear the risk of loss of any fuel after the Fuel Delivery Point and shall only be responsible for any costs, damages, fines or penalties associated with leaks, spills, remediation, or other causes associated with such fuel after the Fuel Delivery Point

(B) Seller shall accept delivery of all Acceptable Natural Gas Fuel delivered to the Fuel Delivery Point for the purpose of generating the Contract Energy from the Facility dispatched by Company to the full extent the Contract Capacity from the Facility is available to be dispatched. Seller shall not be obligated to accept natural gas fuel delivery to the extent Seller reasonably determines it does not materially conform to the specifications for Acceptable Natural Gas Fuel as set for the in Exhibit K-Fuel Quality Specifications, and that such nonconformance could reasonably be expected to have a Material Adverse Effect on the Facility ("Nonconforming Gas").

1. In the event that the Upstream Pipeline delivers Nonconforming Gas, Seller may refuse to consume such gas and cease delivering Contract Energy for the period of time that such natural gas fuel constitutes Nonconforming Gas. Seller shall promptly notify Company and the Upstream Pipeline of such Nonconforming Gas and the basis for its determination. The Parties shall cooperate to promptly identify and share any relevant information to determine the

cause(s) for the delivery of the Nonconforming Gas and to enforce any available remedies against the Upstream Pipeline or other third parties arising out of the delivery of such Nonconforming Gas.

2. In the event the Upstream Pipeline proposes to change its tariff specifications and requirements such that the fuel available for delivery constitutes Nonconforming Gas, Seller shall cooperate with Company to resist such changes and shall cooperate with Company to enforce all available remedies against the Upstream Pipeline or other third parties regarding such proposed change. In the event that the Upstream Pipeline successfully revises its tariff specifications and requirements for natural gas fuel such that the fuel available for delivery constitutes Nonconforming Gas: (i) at Company's request and expense, Seller shall modify the Facility or other equipment to allow the Facility to utilize such Nonconforming Gas, *provided, however, that* such modification is not required if it would void the manufacturer's warranty for such equipment then in effect or would have a Material Adverse Effect on the operation of such equipment, or (ii) at Company's request and expense, Seller shall construct and operate an appropriate natural gas conditioning facility at a reasonably convenient location, to condition the natural gas fuel to satisfy the requirements for Acceptable Natural Gas Fuel.

(C) As between the Parties, Seller shall be solely responsible for all natural gas interconnection, transportation, delivery and metering arrangements, and all associated costs, required to receive natural gas fuel at the Fuel Delivery Point to operate the Facility. Seller shall, at its sole expense, construct or cause to be constructed and, to the extent necessary, operate and maintain the Natural Gas Interconnection Facilities, natural gas metering facilities, any natural gas compression, regulation, heating and filter/separation equipment, and all other necessary equipment, of sufficient size and specifications to receive natural gas deliveries at the Fuel Delivery Point sufficient for the full operation of the Facility over the Term.

1. Seller shall separately meter and supply, at Seller's expense, the natural gas fuel consumed by the auxiliary boiler that will be used for both MEC I Facility and the Facility. Seller shall pay Company an amount equal to the applicable volume of fuel multiplied by the Daily Gas Cost.

2. Company may elect at Company's sole option whether to obtain and utilize firm gas transportation service or non-firm gas transportation service for the delivery of natural gas fuel to Seller at the Fuel Delivery Point.

3. Company may elect at Company's sole option to interconnect the Facility with one or more additional natural gas delivery systems at or near the Fuel Delivery Point identified in Exhibit C-Facility Description, One-Line Diagram, And Site Map and to designate such an additional interconnection as an additional Fuel Delivery Point, *provided, however, that* (i) Company shall be responsible for installing and paying for all natural gas interconnection and metering facilities required to establish such additional interconnection; (ii) such additional interconnection will not interfere with the operation of the Facility, other than during the

time necessary to physically connect the additional interconnecting facilities; and (iii) such additional interconnection will deliver natural gas fuel that provides the equivalent of Acceptable Natural Gas Fuel to the Fuel Delivery Point. Seller shall, with respect to any real property interests of Seller or its Affiliates, grant, or cause any such Affiliate to grant, Company or its designee an easement and access to the location of the Fuel Delivery Point for the purpose of constructing and maintaining any additional natural gas interconnection and metering facilities.

4. Company shall be responsible for all volume confirmations, allocations and balancing functions with the Upstream Pipeline. Seller shall be responsible for gas regulation and maintenance and testing arrangements for all natural gas metering from the Fuel Delivery Point. Seller shall also be responsible for all natural gas physical flow activities, such as flow control, valve operation, and contacting the delivering pipeline to initiate gas flow from the Fuel Delivery Point.

5. All natural gas custody transfer metering at the Fuel Delivery Point shall be installed, maintained and tested in accordance with accepted natural gas industry standards and shall comply with the Upstream Pipeline's tariff requirements. Seller shall provide written meter test results to Company within 30 days following completion. Company shall have the right to require additional tests, *provided, however, that* Company pays for the cost of such additional tests. Seller shall provide Company with at least 10 Business Days advance notice of such tests and a representative of Company shall be permitted to witness such tests, *provided, however, that* such Company representative shall not unreasonably interfere with or disrupt the activities of Seller and shall comply with all of Seller's safety standards. Seller shall provide copies of all test data and testing reports to Company. If requested by Company in writing, Seller shall install (at Company's cost) check metering, in connection with the natural gas custody transfer metering, downstream from the Fuel Delivery Point. Disputes regarding the allocation of natural gas volumes and associated billings with the Upstream Pipeline, including meter reading adjustments for prior periods, shall be resolved in accordance with the Upstream Pipeline's tariff.

Article 6 - Conditions Precedent

6.1 Company CPs.

(A) No later than 15 Business Days after execution of this PPA, Company may make written request for State Regulatory Approval. If Company fails to apply for State Regulatory Approval within 15 Business Days following execution of this PPA, Company shall be deemed to have waived its right to seek such approval under this Section and, subject to the other terms and conditions of this PPA, this PPA shall remain in full force and effect thereafter.

(B) In the event that Company applies for State Regulatory Approval, Company shall have the right to terminate this PPA, without any further financial or other obligation to Seller as a result of such termination, by Notice to Seller not more

than 10 Business Days after the earlier of: (i) receipt of any written order from a State Regulatory Agency rejecting State Regulatory Approval or granting such approval with conditions reasonably and materially unsatisfactory to Company; or (ii) April 1, 2015, in the event Company has not received State Regulatory Approval as of such date; *provided, however, that* if Company has not received State Regulatory Approval by April 1, 2015, Company may provide Seller Notice within 48 hours after said date that it is electing to wait until July 1, 2015 for such approval and Seller shall then have the right to delay the COD from June 1, 2018 to June 1, 2019 at no cost to Company, notwithstanding anything to the contrary in Section 2.3, and *provided, further, that* the Parties shall revise Exhibit B-Construction Milestones to this PPA to extend the Commercial Operation Milestone and other Construction Milestones to reflect the impacts of such delay of the COD of the Facility. If Company fails to terminate this PPA in the time allowed by this paragraph, Company shall be deemed to have waived its right to terminate this PPA under this Section and, subject to the other terms and conditions of this PPA, this PPA shall remain in full force and effect thereafter.

6.2 Seller CPs. 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 within 14 Business Days following the failure of Seller to satisfy any of the Seller CPs by the required deadline date in the table below. In the event that COD is delayed pursuant to Sections 2.3 or 6.1(B), the Parties shall revise the deadline dates in the table below to reflect the impacts of such delay of the COD of the Facility. If neither Party terminates this PPA in the time allowed by this Section, the Seller CPs shall be deemed to have been waived and, subject to the other terms and conditions of this PPA, this PPA shall remain in full force and effect thereafter.

Condition Precedent	Deadline Date
Seller has obtained the Air Permit, which Permit does not contain conditions reasonably and materially unsatisfactory to Seller.	September 1, 2016
Seller has obtained the Site Permit, which Permit does not contain conditions reasonably and materially unsatisfactory to Seller.	June 1, 2016
Transmission Owner, Transmission Authority and Seller have entered into the Interconnection Agreement.	June 1, 2016
Approval of this PPA, in the form submitted by Company to the MPUC for approval, by the board of directors of Calpine Corporation.	December 1, 2014
Approval of this PPA by the board of directors of Calpine Corporation in the event any conditions are added or modifications are made to this PPA	Thirty (30) Days after issuance of any order requiring such additional conditions or modifications

after its submittal to the MPUC for approval	
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Article 7 - Sale and Purchase

7.1 General Obligation.

(A) Beginning on the Commercial Operation Date, Seller shall generate from the Facility, deliver to the Point of Delivery, and sell to Company, and Company shall receive and purchase from Seller at the Point of Delivery, the products and services required by this PPA. Seller shall not curtail or interrupt deliveries from the Facility required by this PPA for economic reasons of any type whatsoever.

(B) Title and risk of loss of the products and services transacted by this PPA shall transfer from Seller to Company at the Point of Delivery.

7.2 Capacity and Energy.

(A) Contract Capacity shall be the net generating capacity available at any time from the Facility.

(B) Contract Energy shall be the metered, net energy output generated by the Contract Capacity as delivered and adjusted for losses to the Point of Delivery, which shall include Test Energy produced when the Facility is otherwise dispatched by Company as provided in Section 4.4(B).

7.3 Alternate Generation Sources.

(A) If after the Commercial Operation Date more than 50 MW of the Facility is unavailable due to a Forced Outage, Seller may upon Notice use Alternate Generating units and /or systems ("Alternate Generation Source(s)") to provide Contract Energy to Company in accordance with this Section 7.3. Unless otherwise mutually agreed to by the Parties, Seller shall not use an Alternate Generating Source once such Forced Outage is remedied or less than 50 MW of Facility is unavailable.

1. Delivery of Contract Energy from an Alternate Generation Source must be made to either NSP.NSP or NSP.MEC ("Alternate Delivery Point(s)"). The Alternate Generation Source(s) designated by Seller shall: (i) not, in the aggregate, exceed the Nameplate Capacity of the Facility; (ii) not be subject to or limited by any operating restrictions imposed by any Governmental Authorities that would prohibit its use for the purposes hereof; and (iii) be available to be scheduled by Company.

(B) General Alternate Generation Source Provisions.

1. Notice for Contract Energy from an Alternate Generation Source must be provided no later than two (2) hours before each applicable daily

submission deadline for the Transmission Authority's Day-Ahead Market. Such Notice from Seller shall include (i) a description of the Forced Outage, (ii) the amount and Alternate Delivery Point(s) of the Contract Energy deliverable from each Alternate Generation Source, and (iii) the period(s) during which such Contract Energy will be provided.

2. Company shall submit to Seller schedules for hourly deliveries of Contract Energy from Alternate Generation Source(s) ("Day-Ahead Bilateral Financial Schedule") no later than one (1) hour after the Transmission Authority posts the next-day nodal Locational Marginal Pricing.

3. Company's submittal and Seller's confirmation of a Day-Ahead Bilateral Financial Schedule shall be deemed to be delivered energy at the designated Alternate Delivery Points.

4. Company shall settle with the Transmission Authority pursuant to the Day-Ahead Bilateral Financial Schedule.

5. Seller shall be responsible for any Transmission Authority charges associated with deliveries of Contract Energy from the Alternate Generation Source(s) to the Alternate Delivery Point(s) ("Transmission Authority Charges").

6. Company shall make the following payments to Seller with respect to Contract Energy from Alternate Generation Source(s): (i) payment for Contract Energy from Alternate Generating Sources(s) calculated as (Contract Energy x Tolling Price x Inflation Factor; and (ii) a Scheduling Charge for each schedule of an Alternate Generation Source that would qualify for a Turbine Start Payment if the schedule were for the Facility; and (iii) Company shall pay the sum of Seller's fuel costs associated with Contract Energy from Alternate Generation Source(s), where "Seller's fuel costs" for any Day shall equal the product of (a) the Daily Gas Cost for that Day, multiplied by (b) the quantity of Contract Energy from Alternate Generation Source(s) that is scheduled by Company and delivered by Seller to Company at the Alternate Delivery Point(s) on that Day, multiplied by (c) the most recent Actual Net Heat Rate for the Facility.

7. Seller shall have no obligation to cause or seek to cause any Alternate Generation Source to be subject to AGC, nor shall the Company be obligated to make payments for AGC service for any Alternate Generation Source deliveries. An Alternate Generation Source may be owned or controlled by Company or an Affiliate of Company or Seller or an Affiliate of Seller; *provided, however, that* the Alternate Generation Source may not be the MEC I Facility while subject to a power purchase agreement with the Company.

8. With respect to Alternate Generation Sources, the Company shall only pay for such costs and charges as expressly provided in this Section 7.3.

7.4 Dispatch.

(A) Company's EMCC shall have the right to determine the AGC control of the Facility, starts, shutdowns, ramping, and loading levels associated with the Contract Capacity and Contract Energy from the Facility, all in accordance with Good Utility Practices and the Facility operational information in Exhibit N-Facility Operational Information. Company shall not dispatch any portion of the Facility below Minimum Loading. For any Facility trip, Seller shall restart the Facility in coordination with the EMCC in accordance with Good Utility Practices.

(B) If Seller initiates a turbine start in response to a request by the Company, but fails to satisfy the requirements for a Successful Start as a result of: (i) the cancellation of the turbine start by Company within the applicable time period permitted for a Successful Start, (ii) a request from Company, within one hour from Facility start, to shut down the Facility, or (iii) a Company or Company system performance failure, then the initiated turbine start shall nevertheless qualify as a Successful Start. Seller shall not be credited a Successful Start following a turbine trip where Company directs the Seller to restart the Facility after it has tripped out of service even if the restart would otherwise meet the qualifications for a Successful Start.

(C) Each Party shall make Commercially Reasonable Efforts to avoid taking any action that would result in or materially contribute to a restriction under any Permit that would restrict or limit the delivery of any Contract Energy from the Facility.

7.5 Other Products and Services.

(A) Except as provided in Section 7.2 (C), Seller shall make available to Company all Generation Benefits and Ancillary Services associated with the Facility at no additional charge under this PPA, except for Reactive Power. Any compensation Seller receives under the Interconnection Agreement or otherwise for Generation Benefits or Ancillary Services, other than Reactive Power, associated with the Facility and its output shall be provided to Company at no additional cost to Company under this PPA. Seller shall credit Company, as a reduction to Seller's monthly invoice or other mutually-agreed mechanism, for any compensation that Seller receives for Generation Benefits or Ancillary Services, other than Reactive Power, associated with the Facility and its output.

1. Seller shall use Commercially Reasonable Efforts to maximize the availability of Generation Benefits and Ancillary Services available from the Facility, *provided, however, that* Seller shall not be required to make any material capital expenditures or incur any material increased operating expenses in connection with such efforts.

2. In the event a Governmental Authority or Transmission Authority implements new or revised requirements for generators to create, modify, change, or supply Ancillary Services other than Reactive Power, requiring Seller to

install additional equipment after the Commercial Operation Date to meet such requirements, then Seller shall install such additional equipment at Seller's expense, up to a cumulative amount equal to **[Trade Secret Data Begins... Trade Secret Data Ends]** during the Term. If such requirements require Seller to incur expenditures exceeding this cumulative amount during the Term, Seller and Company shall cooperate to determine and implement a mutually agreeable and Commercially Reasonable response to such requirements.

3. Seller shall be entitled to all revenue from Reactive Power associated with the Facility.

Article 8 - Payment Calculations

8.1 Capacity Payments.

(A) Capacity Testing of the Facility. For purposes of calculating Seller's Capacity Payment only, Seller shall test or cause to be tested the net generating capability of the Facility, at Seller's expense, (a) immediately prior to the Commercial Operation Date (the "Initial Capacity Test"), and (b) thereafter annually during the Term. The annual capacity test shall be conducted between January 1 and March 1 of each calendar year, unless the Facility is scheduled for a major overhaul prior to April 15 (in which case the capacity test for that year shall be conducted promptly following completion of the major overhaul).

1. For avoidance of doubt, the capacity testing requirements for calculating the Capacity Payment under this Article are not the capacity testing requirements that Seller shall complete as required by the Transmission Authority for the Facility to be accredited as a Capacity Resource pursuant to Section 10.6.

2. Upon request by Company from time to time following the Commercial Operation Date, not more frequently than twice per calendar year, Seller shall perform interim capacity testing of the Facility for purposes of calculating Seller's Capacity Payment. The Parties' out-of-pocket costs of any such interim testing requested by Company shall be borne by Company unless, upon such testing, the Net Capability of the Facility is determined to be more than one percent (1%) less than the Net Capability of the Facility determined by the capacity test next preceding the test requested by Company (in which event the Parties' out-of-pocket costs, excluding fuel costs, shall be borne by Seller).

3. Seller may perform interim capacity testing of the Facility from time to time, not more frequently than twice per calendar year (not including any re-testing necessitated by any Failed Capacity Test(s)). The Parties' out-of-pocket costs in connection with any such interim capacity testing shall be borne by Seller.

4. Seller shall set the date for the Initial Capacity Test on not less than five (5) Business Days' prior notice to Company. The Parties shall set the exact date for each subsequent capacity test to be performed under this Article 8 by mutual agreement; *provided that*, in the event that the Parties cannot agree upon a

mutually acceptable testing date within ten (10) Business Days following either Party's request for a test, (a) by notice to Company, Seller shall set the date for the capacity test, which date shall be not less than four (4) weeks and not more than six (6) weeks following expiration of such 10-day period, and (b) the results of the capacity test shall be retroactively effective to the first Day of the billing period immediately preceding the billing period during which the test is conducted.

5. Notwithstanding Section 8.1(A)(4), in the event of a Failed Capacity Test, the capacity test shall be rescheduled unilaterally by Seller as soon as reasonably practicable following the Failed Capacity Test.

6. One or more representatives of Company shall be permitted to witness, record and verify all capacity testing process parameters and conditions; *provided that* any failure of Company to send a representative to witness a capacity test scheduled in accordance with this Section 8.1(A) shall not affect the validity of such test.

7. All capacity testing of the Facility will be conducted with the Facility operating at maximum design load, including full duct firing, using Acceptable Natural Gas Fuel. Testing shall be performed in accordance with mutually agreed upon test codes/procedures generally consistent with the current version of the ASME PTC 46. The test will be conducted over such period as Company may reasonably require, not to exceed four (4) hours, with operation of the unit held constant. Appropriate operational stability criteria shall be established and met. The Facility shall be operated in full compliance with all state and federal environmental regulations throughout the test, with all auxiliary equipment needed for normal operation of the Facility in service and in typical operating condition. Seller may be required to provide operational records to be used to substantiate the Normal Mode of Operation. Seller shall provide to Company copies of all capacity testing reports.

8. For purposes of calculating the test results of the Facility, each hour of the test will be averaged and adjusted to Reference Conditions. After all adjustments have been made, the final capacity value used for purposes of determining Net Capability, as applicable, will be the average output of the hourly corrected results.

(B) Net Capability. For purposes of this PPA, the Net Capability of the Facility from time to time shall mean the lesser of (a) three hundred forty five (345) MW, or (b) the net generating capability of the Facility, as determined by the most recent capacity test thereof in accordance with Section 8.1(A), adjusted to Reference Conditions.

(C) Monthly Payments. Commencing on the Commercial Operation Date, Company shall pay to Seller in arrears a monthly capacity payment ("Capacity Payment"). All Capacity Payments shall be billed on a calendar month basis. Payments for partial calendar months shall be prorated appropriately. Capacity Payments shall be computed based upon the following formula:

Capacity Payment = NC x CP x AAQ, where:

NC = the then-current Net Capability of the applicable Facility.

CP = Capacity Price, stated in \$/kW-month, as set forth in the definitions.

AAQ = Availability Adjustment Quotient for that month, as defined in Section 8.1(D) below.

(D) Availability Definitions.

1. General. For purposes of this PPA, with respect to both On-Peak Months and Off-Peak Months:

Available The Facility is deemed “Available” if and to the extent it is capable of generating and delivering energy to Company at the applicable Point of Delivery, in response to dispatch/scheduling requests by Company, irrespective of whether such requests were actually issued.

AE Available Energy for any month or other measurement period means the amount of energy, stated in megawatt hours (MWh), Available from the Facility during that period; *provided that* regardless of actual Availability, the Facility shall be deemed to be Available during periods of (i) Excused Outage with respect to that Facility and (ii) Forced Outage with respect to the Facility when Seller provides Contract Energy pursuant to Section 7.3. AE shall be adjusted to Reference Conditions.

SME Scheduled Maintenance Energy for any month or other measurement period means the amount of energy, stated in MWh, that was not available from the Facility for dispatch and receipt by Company during the period due to outages / deratings that meet the requirements for credited Scheduled Maintenance Energy specified in Exhibit L- Maintenance Requirements. SME shall be adjusted to Reference Conditions. Seller will be eligible for SME with respect to (and only with respect to) the Facility, and only after the Commercial Operation Date.

PE Period Energy for any month or other measurement period means the product of the then-current NC and the total number of hours in the period, stated in MWh.

CAF Capacity Availability Factor for any month or other measurement period = $(AE + SME) \div PE$. CAF can never exceed 1.0.

2. On-Peak Months. For purposes of this Agreement, with respect to On-Peak Months:

MAF Monthly Availability Factor = CAF + 0.03.

RAF Rolling Availability Factor for any month means the rolling twelve-month average of the MAF for the On-Peak Month in question and the eleven (11) prior full On-Peak Months; *provided, however, that:*

- i. commencing as of COD and continuing through the end of the twelfth (12th) full On-Peak Month following the COD, RAF for On-Peak Months shall be calculated on a monthly basis (i.e., RAF = MAF for that On-Peak Month);
- ii. beginning as of the end of the twelfth (12th) full On-Peak Month following the Commercial Operation Date, RAF shall mean the rolling twelve-month average of MAF for the On-Peak Month in question and the previous eleven (11) On-Peak Months; and
- iii. notwithstanding the foregoing, (a) during the period of any default by Seller under this PPA that affects the Availability of a Facility during an On-Peak Month, regardless of whether the default is subsequently cured or becomes an Event of Default, RAF shall be calculated on a monthly basis (i.e., RAF = MAF for that period), and (b) if the default is subsequently cured, RAF following such cure shall be calculated with the MAF during the period of default assumed to equal 1.0.

AAQ Availability Adjustment Quotient for any On-Peak Month means either:

- i. AAQ = RAF, if $RAF \geq 1.0$, or
- ii. AAQ = $(2 \times RAF) - 1.0$, if $RAF < 1.0$ (*provided that AAQ may not be less than zero*).

3. Off-Peak Months. For purposes of this PPA, with respect to Off-Peak Months:

MAF Monthly Availability Factor = CAF + 0.06.

RAF Rolling Availability Factor for any month means the rolling twelve-month average of the MAF for the Off-Peak Month in question and the eleven (11) prior full Off-Peak Months; *provided, however, that:*

- i. commencing as of COD and continuing through the end of the twelfth (12th) full Off-Peak Month following the COD, RAF for Off-Peak Months shall be calculated on a monthly basis (i.e., $RAF = MAF$ for that Off-Peak Month);
- ii. beginning as of the end of the twelfth (12th) full Off-Peak Month following the COD, RAF shall mean the rolling twelve-month average of MAF for the Off-Peak Month in question and the previous eleven (11) Off-Peak Months; and
- iii. notwithstanding the foregoing, (a) during the period of any default by Seller under this PPA that affects the Availability of a Facility during an Off-Peak Month, regardless of whether the default is subsequently cured or becomes an Event of Default, RAF shall be calculated on a monthly basis (i.e., $RAF = MAF$ for that period), and (b) if the default is subsequently cured, RAF following such cure shall be calculated with the MAF during the period of default assumed to equal 1.0.

AAQ

Availability Adjustment Quotient for any Off-Peak Month means either:

- i. $AAQ = 1.0$, if $RAF \geq 1.0$, or
- ii. $AAQ = (2 \times RAF) - 1.0$, if $RAF < 1.0$ (*provided that AAQ may not be less than zero*).

8.2 Payment for Dispatchability.

(A) Ramp Rate Testing. Company's EMCC shall test or cause to be tested the ramp rate of the Facility, after synchronization with the Transmission Authority's System at Company's expense, (i) before or immediately following the Commercial Operation Date, and (ii) thereafter in Company's discretion, without prior notice to Seller, periodically during the Term from time to time. At Seller's request, Company shall test the ramp rate of the Facility at Seller's expense at a mutually agreeable time no later than thirty (30) Days after Notice of such request. Company shall provide to Seller copies of all ramp rate testing reports. Ramp rates shall consist of four (4) tests: the unfired increasing ramp rate for the Base Capacity, the unfired decreasing ramp rate for the Base Capacity, the fired increasing ramp rate, and the fired decreasing ramp rate. Increasing ramp rates shall include the entire specified ramp rate range, beginning at or below the applicable minimum load of the ramp rate range, and ending at the maximum output for the selected configuration during the hour of the test, adjusted to Reference Conditions. For the unfired ramp rate test, the maximum output shall be the Facility output when the gas turbine and steam turbine

reach baseload. For the fired ramp rate test, the test shall end when the Facility output, adjusted to Reference Conditions, reaches the Net Capability during the hour of the test. The timed portion of the test used to determine the increasing ramp rate shall begin when the Facility is synchronized and its output level reaches the minimum load starting point of the specified ramp range, and shall end one (1) MW prior to achievement of the maximum load point of the ramp range. The timed portion of the test used to determine the decreasing ramp rate shall begin when the Facility output level is at the maximum load point of the ramp range and shall end one (1) MW prior to reaching the minimum load point. The Ramp Rate used to determine RRAF shall be calculated by the following formula:

$$\text{Ramp Rate} = \sum (.38 \times \text{UIR}) + (.38 \times \text{UDR}) + (.12 \times \text{FIR}) + (.12 \times \text{FDR}), \text{ where:}$$

- UIR = the measured unfired increasing ramp rate.
- UDR = the measured unfired decreasing ramp rate.
- FIR = the measured fired increasing ramp rate.
- FDR = the measured fired decreasing ramp rate.

(B) Monthly Payments. Commencing on the Commercial Operation Date Company shall pay to Seller in arrears a monthly Dispatchability Payment. All Dispatchability Payments shall be billed on a calendar month basis; in the event that the Commercial Operation Date does not occur at the start of a calendar month, the first (1st) month's Dispatchability Payment shall be prorated to reflect the actual number of Days of Commercial Operation in such month. Dispatchability Payments shall be computed based on the following formula:

$$\text{Dispatchability Payment} = \text{NC} \times \text{DAF} \times \text{RRAF} \times \text{Dispatchability Rate}, \text{ where:}$$

NC = the then-current Net Capability of the Facility

DAF = Dispatch Availability Factor

= a fraction, the numerator of which is the sum of all hours on-control during the month, and denominator of which is the sum of all hours on-line during the month, where:

Hours on-control = means the total time during the month when the Facility is receiving and responding (or capable of receiving and responding) to dispatch pulses transmitted from Company's EMCC; *provided, however, that* any period during which Company requests that the Facility be dispatched without AGC, and any period of Excused Outage, shall be counted as a period on-control (so that hours on-control/hours on-line = 1.0 for any such period(s)). The Facility will be deemed not on control for any period during which any portion of the Facility is not Available to Company under Section 8.1(D).

Hours on-line = means the total time during the month when any portion of the Facility is synchronized to the Transmission Authority's

System and Available, or when the Facility is not so synchronized or not Available due to an Excused Outage.

For the avoidance of doubt, Start-Up Periods and Shut-Down Periods shall be excluded from hours on-control and hours on-line for purposes of the calculation of DAF.

RRAF = Ramp Rate Availability Factor, determined by the following table:

Most Recently Tested Ramp Rate	RRAF
≥ 10 MW / minute	1.00
< 10 MW / minute; ≥ 5 MW / minute	(Actual Ramp Rate ÷ 5) - 1
< 5 MW / minute	0

8.3 Payment for Energy. Commencing on the Commercial Operation Date, Company shall pay to Seller in arrears a monthly Energy Payment for the Contract Energy that is dispatched/scheduled by Company and delivered by Seller to Company during the billing month. The monthly Energy Payment shall be determined by the following formula:

Energy Payment = (E x Tolling Price x Inflation Factor) - HRA, where:

E = Contract Energy, stated in MWh, that is dispatched or scheduled by Company and delivered by Seller to Company at the Point(s) of Delivery during the billing month.

HRA = Heat Rate Adjustment, determined as a dollar amount pursuant to Section 8.4.

8.4 Heat Rate Adjustment to Payments.

(A) If at any time following the Commercial Operation Date, the Actual Net Heat Rate for the Facility is more than **[Trade Secret Data Begins...**

...Trade Secret Data Ends] of the Predicted Net Heat Rate, a Heat Rate Adjustment (“HRA”) determined by the following formula shall be used to reduce payments to Seller for Contract Energy delivered from the Facility, starting effective with the first (1st) full billing month following the most recent heat rate test and continuing effective through the end of the billing month during which the next heat rate test occurs:

HRA = $\sum DFCC1 \times [1 - (\{Px [Trade Secret Data Begins... \dots Trade Secret Data Ends]\} \div A)]$, where:

$\sum DFCC1$ = Sum of all daily fuel consumption costs (DFCC1s) for that billing month.

DFCC1 = Daily Fuel Consumption Cost for any Day means the sum of (i) the volume of Acceptable Natural Gas Fuel delivered to the Fuel Delivery Point to produce the Contract Energy (including any Test Energy that is economically dispatched by Company) that is dispatched by Company and delivered by Seller to Company on that Day (stated in MMBtu), multiplied by the applicable Daily Gas Cost, plus (ii) the associated demand charges incurred by Company for that Day.

P = Predicted Net Heat Rate at the time of the most recent heat rate test.

A = Actual Net Heat Rate for the Facility as determined from the most recent heat rate test.

(B) If at any time following the Commercial Operation Date the Actual Net Heat Rate for the Facility is less than **[Trade Secret Data Begins...
...Trade Secret Data Ends]** of the Predicted Net Heat Rate, an HRA determined by the following formula shall be used to increase payments to Seller for Contract Energy delivered from the Facility, starting effective with the first (1st) full billing month following the heat rate test and continuing effective through the end of the billing month during which the next heat rate test occurs:

HRA = $\sum DFCC2 \times (1 - [(P \times \text{[Trade Secret Data Begins...
...Trade Secret Data Ends]}) \div A]) \times \text{[Trade Secret Data Begins...
...Trade Secret Data Ends]}$, where " $\sum DFCC2$ " is defined below, and "A" and "P" are as defined in Section 8.4(A):

$\sum DFCC2$ = Sum of all daily fuel consumption costs (DFCC2s) for that billing month.

DFCC2 = (Daily Fuel Consumption Cost) for any Day means the sum of (i) the volume of Acceptable Natural Gas Fuel delivered to the Fuel Delivery Point to produce the Contract Energy (including any Test Energy that is economically dispatched by Company) that is dispatched by Company and delivered by Seller to Company on that Day (stated in MMBtu), multiplied by the applicable Daily Gas Cost, plus (ii) any demand charge savings actually realized by Company.

(C) If the Actual Net Heat Rate for the Facility is equal to or less than **[Trade Secret Data Begins...
...Trade Secret Data Ends]** of the Predicted Net Heat Rate, and is equal to or greater than **[Trade Secret Data Begins...
...Trade Secret Data Ends]** of the Predicted Net Heat Rate, the HRA for the billing month following the heat rate test until the billing month following the next heat rate

test for Contract Energy delivered from the Facility, shall be deemed to be zero dollars (US\$0.00) for purposes of the payment calculations specified in Section 8.4.

8.5 Heat Rate Testing.

(A) The Actual Net Heat Rate shall be determined by heat rate testing of the Facility at the maximum design load for its combustion and steam turbine generators, including full duct firing, using Acceptable Natural Gas Fuel. For the purposes of heat rate testing and determination of the Actual Net Heat Rate, (i) fuel input shall be measured at the Fuel Delivery Point, and (ii) electric output shall be measured as provided in Section 5.2. The test will be conducted over a continuous 4-hour period, with operation of the generating unit held constant. The Facility will be operated in full compliance with all state and federal environmental regulations throughout the test, with all auxiliary equipment needed for normal operation of the Facility in service and in typical operating condition. Seller may be required to provide operational records to be used to substantiate the Normal Mode of Operation. Testing shall be performed in accordance with the then-current ASME PTC 46. The net heat rate of the Facility so determined shall then be subject to one or two adjustments:

1. in the event that the capacity test of the Facility conducted simultaneously with the heat rate test yields (or, if no capacity test is conducted simultaneously, the capacity test most recently conducted yielded) a Net Capability for the Facility in excess of three hundred forty five (345) MW, the tested heat rate for each hour of the test shall be adjusted to the heat rate that would have been obtained had the duct firing rate during the test been limited to such rate as would have yielded a Net Capability of three hundred forty five (345) MW; and

2. following any adjustment pursuant to Section 8.5(A)(1), the tested net heat rate for each hour of the test shall be adjusted to Reference Conditions. Uncertainty, as defined in the ASME power test codes, shall not be used to adjust heat rate test results. After all adjustments have been made, the Actual Net Heat Rate shall equal the average tested net heat rate of the Facility, as adjusted, for each of the four (4) hours of the test.

(B) Seller shall perform an initial heat rate test of the Facility prior to or within thirty (30) Days following the Commercial Operation Date ("Initial HR Test"). Seller shall provide to Company at least five (5) Business Days' prior notice of, and shall permit one or more representatives of Company to witness and verify, the Initial HR Test. If the Initial HR Test is performed after the Commercial Operation Date, the Actual Net Heat Rate resulting from such Initial HR Test shall apply retroactively from the Commercial Operation Date for the purposes of determining the Heat Rate Adjustment pursuant to Section 8.4. The heat rate test performed by or on behalf of Seller prior to the Commercial Operation Date may constitute the Initial HR Test, provided, that such test is performed in accordance with all the requirements for heat rate testing set forth in this Section 8.5. Seller shall perform the Initial HR Test at Seller's cost.

(C) Following the Commercial Operation Date, Seller shall perform an annual heat rate test of the Facility concurrently with the annual capacity testing of the Facility prescribed in Section 8.1(A). Seller shall perform the annual heat rate test of the Facility at Seller's cost.

(D) Each Party shall have the right to request and schedule an interim heat rate test of the Facility (not to exceed two interim tests per Party) on a Business Day, between annual heat rate tests, pursuant to the procedures set forth in this Section 8.5. Seller shall perform any and all interim heat rate tests. The Party requesting such test shall pay all costs thereof. The Parties shall set the exact date for each interim heat rate test by mutual agreement; *provided that*, in the event that the Parties cannot agree upon a mutually acceptable testing date within ten (10) Business Days following either Party's request for an interim heat rate test, by notice to Company, (i) Seller shall set the date for the test, which date shall be not less than four (4) weeks and not more than six (6) weeks following expiration of such 10-day period, and (ii) the results of the heat rate test shall be retroactively effective to the first Day of the billing period immediately preceding the billing period during which the test is conducted.

(E) Seller shall prepare and submit to Company for review and approval, at least sixty (60) Days prior to each heat rate test of the Facility, the proposed heat rate test procedures. Such test procedures shall include but not be limited to (i) specification of the governing test code(s), (ii) the extent, if any, to which the test code(s) will not be followed, (iii) provisions for testing, including collection of test data, (iv) operational stability criteria, and (v) methodology for calculating test results, including the planned method of adjusting the tested net heat rate to the NC and Reference Conditions. Seller shall be responsible for the full scope of heat rate testing, including but not limited to, furnishing the test instrumentation, set-up, data gathering, fuel analysis, data analysis and the issuance of a final report. Company shall have the right to install, during the heat rate test and at Company's expense, any temporary, redundant test equipment complying with the governing test code(s), that Company deems necessary for the purpose of verifying test measurements obtained by, or on behalf of, Seller.

(F) Notwithstanding anything to the contrary in this Section 8.5, in the event of a Failed HR Test, the heat rate test shall be rescheduled unilaterally by Seller as soon as reasonably practicable following the Failed HR Test.

(G) One or more representatives of Company shall be permitted to witness, record and verify all heat testing process parameters and conditions; *provided that* any failure of Company to send a representative to witness and verify a heat rate test scheduled in accordance with this Section 8.5 shall not affect the validity of such test.

(H) In connection with and during any heat rate test, for the sole purpose of developing a unit dispatch heat rate curve, Company may also require Seller to perform heat rate testing of the Facility, for up to thirty (30) minutes per load

point after stabilization, at the Facility's Base Capacity and up to nine (9) other specified partial load points.

(I) Seller shall notify Company of any generation equipment tuning and adjustment that may impact the heat rate performance of the Facility or the accuracy of the correction curves utilized to adjust the results of the most recent heat rate test. Upon such notification, Company may require Seller to perform additional heat rate testing of the Facility and provide new correction curves that reflect the actual post-tuning condition of the Facility's equipment.

(J) Within sixty (60) Days following performance of each heat rate test of the Facility, Seller shall provide to Company for review and approval (i) all raw test data, calculations, fuel analyses and a final test report, in written and, to the extent possible, electronic format, (ii) equipment calibration specifications, and (iii) correction curves, equations, and other information necessary for review of the heat rate test results which have not been previously submitted to Company. The final test report shall include clear and complete explanations of the calculations resulting in the Actual Net Heat Rate, including the adjustment of the tested net heat rate to the NC and Reference Conditions.

8.6 Payment for Turbine Starts. Commencing on the Commercial Operation Date, Company shall pay to Seller in arrears monthly a Turbine Start Payment based upon the number of combustion turbine starts at the Facility requested by Company and successfully performed by Seller during the month, and the duration of combustion turbine operation following each such start. Each individual Turbine Start Payment ("TSP") shall be determined by the following formula:

$$\text{TSP} = (\text{Turbine Start Price} \times \text{Inflation Factor}) + ((\text{FH}-25) \times \text{Fired Hour Charge} \times \text{Inflation Factor}), \text{ where:}$$

FH = Fired hours are the greater of (i) twenty five (25), or (ii) number of continuous fired hours for the combustion turbine, following its start.

By way of example, assuming that (i) the Commercial Operation Date is June 1, 2017, (ii) inflation between June 1, 2017 and June 1, 2019 is five and two-tenths percent (5.2%), (iii) Company requests Seller to start the entire Facility or only such Facility's combustion turbine in July 2019, and (iv) following such start, the combustion turbine runs for thirty (30) continuous hours; then the TSP payable with respect to such one start would be: ***[Trade Secret Data Begins...***

...Trade Secret Data Ends] The monthly Turbine Start Payment payable to Seller shall equal the sum of all individual turbine starts during the billing period.

For the avoidance of doubt, a combustion turbine restart at the Facility following a turbine trip not caused by an Excused Outage, all during a single continuous dispatch

period scheduled by Company, shall not constitute a compensable start for purposes of this Section 8.6.

8.7 ESC Event Adjustment.

(A) In connection with each ESC Event during the Term, an adjustment in the payment due to Seller from Company shall be made for the billing period during which the ESC Event occurs ("ESC Event Adjustment"), based upon the Availability of the Facility during the ESC Event as set forth in Exhibit M-ESC Event Adjustment. The ESC Event Adjustment, if any, shall be in addition to (not in lieu of) any adjustment to the Monthly Capacity Payment based upon the Available Energy from the Facility during that billing period, pursuant to Section 8.1.

(B) The Parties shall take such steps as may be necessary from time to time to allow each of Seller and Company to receive notice of ESC Events and anticipated ESC Events.

Article 9 - Billing and Payment

9.1 Billing Invoices.

(A) The billing period shall be the calendar month with any partial months prorated appropriately.

(B) No later than thirty-eight (38) Days following the end of each billing period, Company shall (i) calculate the HRA for such billing month, and (ii) deliver to Seller, electronically, Company's calculation of the HRA together with such supporting data as will allow Seller to verify Company's calculation of the HRA for such billing period.

(C) As soon as practicable following the end of each billing period, Seller shall prepare an invoice for such billing period (a "Monthly Invoice") showing metered energy from the Facility (adjusted for losses at the Point of Delivery), all relevant billing parameters (including starts and fired hours per turbine), rates and factors, and other data reasonably pertinent to the calculation of the monthly payments and other amounts due to Seller for such billing month, and (ii) deliver the Monthly Invoice to Company electronically. All billing data based upon metered deliveries to Company shall be collected in accordance with Article 5. The Monthly Invoice for each billing period shall include the HRA for the next preceding billing period delivered to Seller by Company pursuant to Section 9.1(B), i.e., the HRA shall lag the current Monthly Invoice by one (1) month.

(D) In the event that Seller owes Company any amounts hereunder, including without limitation any indemnification payments, Company shall provide to Seller by electronic transmission an invoice showing the payment due to Company from Seller. The invoice will include any data reasonable pertinent to the calculation of the payment due to Company.

9.2 Payment.

(A) All regular monthly payments payable to Seller from Company for capacity, energy, tolling and other services after COD under Article 8 shall be due and paid by Company by electronic funds transfer, as designated by Seller from time to time, on or before the last to occur of (i) the twenty-fourth (24th) Day of the month following the end of the relevant billing period, or (ii) fifteenth (15th) Day following receipt by Company of the electronic copy of the Monthly Invoice under Section 9.1(C). Unless otherwise specified herein, all other payments under this PPA shall be due and payable by electronic funds transfer, as designated by the owed Party, on or before the fifteenth (15th) Day following receipt of the billing invoice. Remittances received by mail will be considered to have been paid when due if the postmark indicates the payment was mailed on or before the fifteenth (15th) Day following receipt of the billing invoice.

(B) If any amount due under this PPA is not paid on or before the due date, a late payment charge shall be applied to the unpaid balance commencing on such date and continuing until the amount is paid. The late payment charge shall be added to the next billing statement and to subsequent billing statements until the amount due is paid. Such late payment charge shall be calculated based upon a floating annual interest rate equal to the Prime Rate, as the Prime Rate may change from time to time. For purposes of this PPA, the "Prime Rate" as of any Day means the base rate on corporate loans posted by at least seventy-five percent (75%) of the nations thirty (30) largest banks for such Day, as published in the Wall Street Journal from time to time. In the event the Wall Street Journal ceases to publish the "Prime Rate," then Company and Seller shall agree as to an appropriate substitute reference that represents the base rate on corporate loans posted by major banks having one or more lending offices in New York, New York.

(C) Seller and Company shall net their undisputed payment obligations to each other under this PPA, and payment of the resulting net amount will fully discharge the netted underlying obligations between the Parties.

9.3 Billing Disputes.

(A) Either Party may dispute invoiced amounts, but shall pay to the other Party at least the portion of invoiced amounts that is not disputed on or before the invoice due date.

(B) To resolve any billing dispute, the Parties shall use the procedures set forth in Article 13. When the billing dispute is resolved, the Party owing shall pay the amount owed within five (5) Business Days of the date of such resolution, with late payment interest charges calculated on the amount in accordance with the provisions of Section 9.2. Unless an invoice amount is being disputed pursuant to this Section 9.3, all invoices shall be deemed final two (2) years after the date issued and shall not be subject to dispute or audit thereafter.

Article 10 - Operations and Maintenance

10.1 Operation and Administration.

(A) Seller shall staff, control, and operate the Facility consistent with Good Utility Practices and the Operating Procedures. Personnel shall be available at all times via telephone or other electronic means with the ability to be present at the Site within 30 minutes. Company will use Commercially Reasonable efforts to notify Seller at least twenty-four (24) hours in advance of potentially critical turbine starts, and upon such notification and during such identified critical periods, Seller shall make available on-site personnel capable of starting, operating, and stopping the Facility.

(B) Seller shall comply with the requirements of NERC, ERO, Transmission Authority, FERC, or successor organizations, Exhibit H-Operating Standards, Governmental Authority, and Good Utility Practice in the operation of the Facility.

1. To the extent that a Party proximately causes monetary penalties assessed by NERC, ERO, Transmission Authority, FERC, or other Governmental Authority, that Party shall pay for all such monetary penalties so proximately caused.

2. Seller shall be responsible for providing accurate and timely updates on the current availability of the Contract Capacity to Company's EMCC ("Reported Availability"). Company shall have the right to verify at any time, without prior notice to Seller, Seller's current Reported Availability. To verify Seller's Reported Availability, Company shall dispatch the Contract Capacity to the level of Reported Availability ("Availability Verification Test"). If (i) the tested availability (rounded upward to the next whole MW) is less than **[Trade Secret Data Begins...
...Trade Secret Data Ends]** of the Reported Availability (rounded upward to the next whole MW), or (ii) such tested availability is more than five MW below the Reported Availability, such shortfall shall constitute a Deficiency. The Contract Capacity availability shall be derated by the Deficiency for the then current hour and all subsequent hours until Seller reports a revised level of available Contract Capacity. The amount of Contract Capacity available for any individual hour shall be integrated over the hour, on a prorated basis, to reflect any updates in Seller's Reported Availability made effective during such hour.

3. Company will notify Seller as soon as possible by telephone and thereafter in writing whenever an Availability Verification Test has identified a Deficiency. The occurrence of more than one Deficiency in any billing month shall result in derating the Contract Capacity availability retroactive to the beginning of such billing month to the capacity level achieved in the most recent Availability Verification Test. Three Deficiencies in any two consecutive billing months shall result in a five percent reduction in the Capacity Price, as set forth in Section 8.1, applicable to the subsequent two billing months.

10.2 Facility Maintenance.

(A) Seller shall maintain the Facility in accordance with Good Utility Practice and relevant equipment manufacturers' requirements. Seller shall coordinate its regular maintenance requirements for the Facility with Company. Maintenance Schedules shall comply with the requirements of Exhibit L-Maintenance Requirements ("Maintenance Schedule").

(B) Scheduled Outages/Deratings shall be coordinated between the Parties and shall be scheduled to avoid such outages during On-Peak Months.

1. Notwithstanding the foregoing, Company shall have the right to change the start date of any Scheduled Outage/Derating in a Maintenance Schedule; *provided, however, that* the changed start date must be within 45 Days, earlier or later, of the start date set forth for such outage/derating in the most recent Maintenance Schedule provided by Seller; *and provided further that*, Company shall reimburse Seller for the actual incremental direct costs incurred by Seller from third parties as a result of any such changes to the start date. Upon request, Seller shall provide Company its best estimate of the actual incremental direct costs that Seller would incur as a result of such change to the start date, broken out by type of expense and the third party to whom the expense would be owed.

2. Not less than 72 hours (with respect to major overhauls) and 12 hours (with respect to other Scheduled Outages/Deratings) prior to commencement of any Scheduled Outage/Derating, Company may request verbally or in writing, that Seller defer such Scheduled Outage/Derating. Subject to Good Utility Practice, Seller shall comply with any such request and reschedule such deferred maintenance to a subsequent date mutually agreed upon between the Parties if Company agrees to pay Seller the actual incremental direct costs incurred by Seller in such deferral or rescheduling. Seller shall provide to Company, in advance, a non-binding good faith estimate of such costs and Company shall promptly advise whether Company is willing to reimburse Seller to implement such revised schedule.

(C) When Forced Outages occur, Seller shall notify Company's EMCC of the existence, nature, start time, and expected duration of the Forced Outage as soon as practical, but in no event later than one hour after the Forced Outage occurs. Seller shall immediately inform Company's EMCC of changes in the expected duration of the Forced Outage unless relieved of this obligation by Company's EMCC for the duration of each Forced Outage.

1. Seller shall report to Company information on Facility performance during a calendar month within five Business Days after the end of the calendar month. For each turbine generator, and using definitions provided by, or consistent with, the NERC Generation Availability Data System ("GADS") Manual, or any successor document, the data reported shall include planned derated hours, unplanned derated hours, average derated kW from Net Capability during the derated

hours, scheduled maintenance hours, average derated kW during scheduled maintenance hours, the number of turbine starts, hours on-control and hours on-line and a preliminary billing invoice.

2. In addition to the foregoing notification, for any Forced Outage, shutdown, or material derating of the Facility (in each case, not otherwise attributable to any act or omission of Company), Seller shall promptly investigate the cause(s) and take corrective action to prevent reoccurrences in accordance with Good Utility Practices at Seller's cost and expense. Seller shall diligently complete such investigation, identify and implement corrective actions as soon as possible and provide to Company a written report containing a summary of the results of the investigation and the corrective action(s) taken or to be taken as soon as possible.

10.3 Books and Records.

(A) Seller shall maintain an accurate and up-to-date operating log, in electronic format, at the Facility with records of production for each clock hour; changes in operating status; Forced Outages; information required by Applicable Law, Governmental Authority, Transmission Authority, or the ERO in the prescribed format; and other information reasonably requested by Company.

(B) Seller and Company shall each keep complete and accurate records and all other data required by each of them for the purposes of proper administration of this PPA, including such records as may be required by Governmental Authorities, Transmission Authority, NERC or ERO as applicable. All records of Seller pertaining to the operation of a Facility shall be maintained on the premises of the Facility or such other location as is mutually agreed to by the Parties.

(C) Each Party shall keep all books and records necessary for metering, billing and payment for a minimum of two years and shall provide the other Party Commercially Reasonable access to those records.

(D) Each Party shall be entitled to examine and audit the records, data, and other information maintained by the other Party relevant to performance or confirming performance of this PPA at any time and from time to time during the period such records, data, and information are required to be maintained, upon request, on reasonable prior notice, during normal business hours. Each Party's right to audit and examine any documents or other information under this Section shall be subject to any confidentiality obligations of the other Party to any third parties with respect to such documents or information.

10.4 Operating Committee and Operating Procedures.

(A) Company and Seller shall each appoint one representative and one alternate representative to act as the Operating Committee in matters relating to the Parties' performance obligations under this PPA and to develop operating arrangements for the generation, delivery and receipt of any output from the Facility.

Operating Committee representatives shall be included in Exhibit D-Notices And Contact Information.

1. The Operating Committee may develop mutually agreeable written Operating Procedures consistent with the requirements of this PPA, to address matters of day-to-day communications; key personnel; operations-center interface; metering, telemetering, telecommunications, and data acquisition procedures; operations and maintenance scheduling and reporting; reports; operations log; testing procedures; and such other matters as may be mutually agreed upon by the Parties.

(B) The Operating Committee shall review the requirements for AGC from time to time after the date hereof and may agree on modifications thereto to the extent necessary or convenient for operation of the Facility in accordance with this PPA.

(C) The Operating Committee shall have authority to act in all technical and day-to-day operational matters relating to performance of this PPA and to attempt to resolve disputes or potential disputes, *provided, however, that* except to the extent explicitly provided for in this PPA, such representatives and the Operating Committee shall not have the authority to amend or modify any provision of this PPA.

10.5 Access to Facility. Appropriate representatives of Company shall have access to the Facility with Commercially Reasonable prior notice, to read meters and perform inspections as may be appropriate to facilitate the performance of this PPA. While at the Facility, such representatives shall observe such Commercially Reasonable safety precautions as may be required by Seller and shall conduct themselves in a manner that will not interfere with the operation of the Facility.

10.6 Accreditation.

(A) Seller shall at its own expense comply with the Transmission Authority's requirements for the Facility to be accredited as a Capacity Resource for each Commercial Operation Year under this PPA ("Transmission Authority Capacity Accreditation Requirements"), as such requirements are revised from time to time by the Transmission Authority.

(B) If on or prior to January 1 before the Planning Year of COD Seller has obtained the Full Interconnection Agreement, Seller shall deliver to Company Notice on or prior to such January 1 ("Delivery and Supply Commencement Notice") confirming Seller's commitment effective commencing such January 1 ("Delivery and Supply Commencement Notice Effective Date"), to (i) commence its capacity and energy delivery and supply obligations set forth in this PPA and (ii) adhere to the established Commercial Operation Milestone, subject to the terms and conditions in this PPA.

(C) If Seller has provided Company with the Delivery and Supply Commencement Notice as provided in Section 10.6(B), no later than ten (10) Business Days before the Transmission Authority's deadline for accreditation of new

generation for the Planning Year of COD (“Accreditation Deadline”), Seller shall provide Company Notice that it has completed and reported to the Transmission Authority the capacity testing results necessary for the Facility to be accredited by the Transmission Authority as a Capacity Resource (“Necessary Accredited Capacity Testing Results”).

1. Subject to this Section 10.6(C)1 and Section 10.6(C)4, Seller’s failure to provide the Necessary Accredited Capacity Testing Results to the Transmission Authority by the Accreditation Deadline shall be an Event of Default (“Failure to Meet Accreditation Deadline”) notwithstanding anything to the contrary in Articles 12 and 14 of this PPA, which Seller shall be required to cure by paying Company the Auction Clearing Price for the amount of accredited capacity for the Planning Year of COD that Seller failed to obtain as a result of such failure to meet the Accreditation Deadline, which shall be paid within fifteen (15) Days of receipt of Company’s invoice therefor. Upon Seller paying the Auction Clearing Price to Company as specified in this Section 10.6(C)1, the Failure to Meet Accreditation Deadline is cured and Seller shall not be liable to Company for any of the remedies under Article 12 associated with the Events of Default under Sections 12.1(H) or 12.1(K). Seller shall not sell any of the unaccredited capacity of the Facility in any Commercial Operation Year that Seller fails to obtain the Transmission Authority’s re-accreditation of the Facility as a Capacity Resource.

2. Seller shall also provide Company on a monthly basis the amount of Contract Energy that Seller would have provided Company under this PPA for the Planning Year of COD had the Facility obtained accreditation as a Capacity Resource, for which Company shall pay Seller the Energy Payments and monthly Capacity Payments pursuant to Article 8, *provided, however, that* Seller has paid Company the Auction Clearing Price as required under Section 10.6(C)1. If Seller fails to pay the Auction Clearing Price to Company or provide Contract Energy to Company as set forth in this Section, Company shall have the right to terminate this PPA and collect Actual Damages, subject to Section 12.3(A).

3. Subject to Section 10.6(F), Seller thereafter shall at its own expense comply with the Transmission Authority Capacity Accreditation Requirements for the next Planning Year.

4. In the event Seller elects to provide the Necessary Accredited Capacity Testing Results for the Facility for the Planning Year of COD to the Transmission Authority in accordance with the Transmission Authority’s Generation Verification Test Capacity Deferral Requirements (“GVTC Deferral Requirements”) (such election, the “GVTC Deferral Election”), Seller shall provide Notice to Company at least fifteen (15) Days before the Accreditation Deadline. Upon making the GVTC Deferral Election, Seller shall:

a. Take all actions and make all payments required under the GVTC Deferral Requirements until the Facility is accredited as a Capacity Resource for the Planning Year of COD;

b. Take all actions necessary to transfer Seller's capacity rights in the Facility to Company until such time as Company replaces Seller as the registered entity for the Facility for Transmission Authority capacity planning purposes.

c. Provide Company on a monthly basis the amount of Contract Energy that Seller would have provided Company under this PPA for the Planning Year of COD had the Facility obtained accreditation as a Capacity Resource, for which Company shall pay Seller the Energy Payments and monthly Capacity Payments pursuant to Article 8, *provided, however, that* Seller is current in making all payments required under the GVTC Deferral Requirements. Seller's failure to take all actions or make all payments required under the GVTC Deferral Requirements or provide Contract Energy as set forth in this Section shall constitute an Event of Default, for which Company shall have the right to terminate this PPA and collect Actual Damages, subject to Section 12.3(A).

(D) Once Seller has delivered to Company the Delivery and Supply Commencement Notice for the Planning Year of COD, Seller and Company shall take such steps as are necessary under the Transmission Tariff and the Transmission Authority's requirements to timely transfer the registration of the Facility with the Transmission Authority such that Company replaces Seller as the registered entity for the Facility for the Planning Year of COD.

(E) If Seller has not obtained the Full Interconnection Agreement by January 1 before the Planning Year of COD, Seller may at its option elect to delay the COD to the next Planning Year under this Section by delivering to Company on or prior to January 1 before the Planning Year of COD Notice indicating that Seller has elected to delay the Commercial Operation Date to the next Planning Year ("Accreditation Delay Notice"). Seller's right to delay the Commercial Operation Date shall continue for each subsequent Planning Year, subject to the delivery of the Accreditation Delay Notice to Company on or prior to the January 1 before such Planning Year, until such time as the Interconnection Agreement has become a Full Interconnection Agreement. The Parties shall revise Exhibit B-Construction Milestones to this PPA to extend the Commercial Operation Milestone and other Construction Milestones to reflect the impacts of any delay of the COD of the Facility pursuant to this Section 10.6(E).

(F) For each Commercial Operation Year of the PPA after the Facility has been accredited by the Transmission Authority as a Capacity Resource, Seller shall at its own expense comply with all the Transmission Authority's requirements for the Facility to be re-accredited as a Capacity Resource. In the event Seller fails to meet the deadline for such re-accreditation of the Facility for a Commercial Operation Year, Seller shall pay Company the Auction Clearing Price for the amount of accredited capacity for the Commercial Operation Year that Seller failed to obtain through re-accreditation, which shall be paid within fifteen (15) Days of receipt of Company's invoice therefor. Seller shall also provide Company the amount of Contract Energy for the Commercial Operation Year that Seller would have provided

Company under this PPA had the Facility obtained re-accreditation as a Capacity Resource. Seller shall not sell any of the unaccredited capacity of the Facility in any Commercial Operation Year that Seller fails to obtain the Transmission Authority's re-accreditation of the Facility as a Capacity Resource. In the event that Seller fails to pay the Auction Clearing Price to Company or provide Contract Energy to Company as set forth in this Section, such failure shall constitute an Event of Default and Company shall have the right to terminate this PPA and collect Actual Damages, subject to Section 12.3(A).

(G) Notwithstanding any other provision in this PPA, in the event that the Transmission Authority Capacity Accreditation Requirements, the Transmission Tariff and/or the Tariff Authority's planning reserve procedures and requirements with respect to qualifying generation facilities as a Capacity Resource are changed, modified or revised such that the framework as contemplated in this Section 10.6 cannot be implemented or cannot be implemented without an unanticipated Material Adverse Effect on one or both of the Parties, the Parties shall in good faith promptly amend or modify this Section 10.6 to address such change(s), modification(s) or revision(s) in a manner consistent with the intentions of the Parties as originally set forth in this Section 10.6.

Article 11 - Security for Performance

11.1 Security Fund.

(A) No later than 60 (sixty) Days following Company obtaining or waiving State Regulatory Approval from the State Regulatory Agency, Seller shall establish, fund, and maintain a Security Fund that is available to pay any amount due and owing to Company pursuant to this PPA, and to provide Company security that Seller will satisfy its obligations under this PPA.

1. The Security Fund shall equal the Pre-COD Security Fund up to the COD and the Post-COD Security Fund on and after the COD and throughout the Term.

2. In the event of any draw by Company on the Security Fund, regardless of the nature of the collateral upon which such draw is actually made, for purposes of determining the required mix of the Security Fund to be posted by Seller following such draw, such draw shall be deemed to have been made against the HGC and non-HGC posted by Seller, *pro rata* to the applicable amounts thereof set forth in the tables in Section 11.1(D), rounded to the nearest whole thousand dollars. Subject only to the foregoing regarding the relative mix of collateral, and notwithstanding anything to the contrary in this PPA, Seller shall not be required to replenish the amount of Security Fund following any draw thereon by Company.

(B) Company may draw from the Security Fund such amounts as are necessary to recover undisputed amounts due and owing to Company pursuant to this PPA, including any damages due to Company and any amounts for which Company is

entitled to indemnification under this PPA if Seller does not pay such amounts within five (5) Business Days following written demand by Company therefor. Company may, in its sole discretion, draw all or any part of such amounts due to it from any form of security to the extent available pursuant to this Section and in any sequence Company may select. Company's failure or delay to draw any amount from the Security Fund in any instance shall not prejudice Company's rights to subsequently recover such amount from the Security Fund or in any other manner.

(C) The Security Fund shall be maintained at Seller's expense and, to the extent applicable, shall be originated by or deposited in a financial institution or company ("Issuer") satisfying the requirements of this Section; and shall be in the form of one or more of the following instruments:

1. The Security Fund may be in the form of an irrevocable standby letter of credit substantially in the form of Exhibit G-1-Form of Letter of Credit, with such modifications as may be required by the Issuer of such letter of credit, subject to Commercially Reasonable review and approval by Company (the "Letter of Credit").

a. The Issuer for the Letter of Credit shall have and maintain a senior unsecured bond rating (unenhanced by third-party support) equivalent to A- or better as determined by all rating agencies that have provided such a rating, and if ratings from either Standard & Poor's and Moody's are not available, equivalent ratings from alternate rating sources reasonably acceptable to Company. If such rating is equivalent to A-, the Issuer must not be on negative credit watch or have a negative outlook by any rating agency.

b. The Letter of Credit must be for a minimum term of 360 Days. Seller shall cause the renewal or extension of the Letter of Credit for additional consecutive terms of 360 Days or more (or, if shorter, the remainder of the Term) no later than 30 Days prior to each expiration date of the security. If the Letter of Credit is not renewed or extended at least 30 Days prior to its expiration date or otherwise is terminated early, Company shall have the right to draw immediately upon the Letter of Credit and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an interest bearing escrow account in accordance with subparagraph (2) below, until and unless Seller provides a substitute form of such security meeting the requirements of this Section.

c. Seller shall have the right to change the amount of Security Fund provided by Letter of Credit in accordance with the other requirements of this Section by amending an existing Letter of Credit or providing a new or replacement Letter of Credit. Seller shall provide no less than thirty (30) Days Notice of such change to Company. Company shall use Commercially Reasonable Efforts to cooperate with Seller in effecting any such change.

2. The Security Fund may be in the form of United States currency, in which Company holds a first and exclusive perfected security interest,

deposited with an Issuer who is a state or federally-chartered commercial bank with operations in the State in which the Facility is located (or such other escrow agent acceptable to Company in its Commercially Reasonable discretion) in an account under which Company is designated as beneficiary with sole authority to draft from the account or otherwise access the security (the "Escrow Account"). The Escrow Account shall be established pursuant to an Escrow Agreement substantially in the form of Exhibit G-3-Form of Escrow Agreement. Funds held in the Escrow Account may be deposited in a money-market fund, short-term treasury obligations, investment-grade commercial paper and other liquid investment-grade investments with maturities of three months or less, with all investment income thereon to be taxable to, and to accrue for the benefit of, Seller. After the Commercial Operation Date, periodic sweeps by Seller for recovery of interest earned by the escrowed funds shall be allowed.

3. The Security Fund may consist of a guaranty substantially in the form of Exhibit G-2-Form of Guaranty, from the direct or any indirect parent of Seller (a "Parent Guaranty") with a minimum net worth of at least **[Trade Secret Data Begins... ...Trade Secret Data Ends]**. Said parent shall have a senior unsecured credit rating (unenhanced by third-party support) consistent with the credit ratings set forth in the tables in Section 11.1(D), which rating shall be as determined by all rating agencies that have provided such a rating, and if ratings from both Standard & Poor's and Moody's (or if either one or both are not available, equivalent ratings from alternate rating sources reasonably acceptable to Company). The amount of the Security Fund secured by the Parent Guaranty shall be based on the credit rating of such parent as set forth in the tables in Section 11.1(D). If the credit rating of the parent is downgraded to a level that requires a reduction in the amount of the Parent Guaranty as set forth in the tables in Section 11.1(D), to the extent Seller desires to retain the Parent Guaranty as part of the Security Fund, Seller shall, no later than ten (10) Business Days after receiving Notice from Company, amend or replace the Parent Guaranty such that the amount of the guaranty corresponds to the amount set forth in the tables in Section 11.1(D) for a parent possessing the credit rating of such parent following the downgrade.

(D) Seller may change the form or mix of the Security Fund at any time and from time to time upon thirty (30) Days prior Notice to Company, *provided, however, that* the Security Fund must at all times satisfy the requirements of this Section. Security satisfying the requirements of Section 11.1(C)1 or 11.1(C)2 shall be "High Grade Collateral" or "HGC". In the event that the Security Fund ever fails to meet the criteria set forth herein, Seller shall replace such collateral and take such other actions as are necessary to cause the Security Fund to be in compliance with this Section 11.1 within thirty (30) Days following such failure. The required mix of collateral constituting the Security Fund from time to time shall be as follows:

1. Prior to COD:

a. If and for so long as Seller's equity investment in the Facility is less than **[Trade Secret Data Begins...**

...Trade Secret Data Ends]

b. If and for so long as Seller's equity investment in the Facility is **[Trade Secret Data Begins...**

...Trade Secret Data Ends]

2. On or after COD:

a. If and for so long as Seller's equity investment in the Facility is less than **[Trade Secret Data Begins...**

...Trade Secret Data Ends]

b. If and for so long as Seller's equity investment in the Facility is **[Trade Secret Data Begins...**

...Trade Secret Data Ends]

(E) The Security Fund shall survive termination of this PPA to be available to pay any amounts owed to Company arising prior to or upon termination. Promptly following (i) the end of the Term and the completion of all of Seller's obligations under this PPA, or (ii) termination of this PPA for any reason prior to the end of the Term. Company shall determine the amount, if any, owed by Seller for any obligations or damages arising out of this PPA. Company may draw such amount and shall release the balance of the Security Fund (including any accumulated interest, if applicable) to Seller within forty-five (45) Days of termination of this PPA.

(F) Seller shall reimburse Company for the incremental direct expenses (including the fees and expenses of counsel) incurred by Company in connection with the preparation, negotiation, execution and/or release (including making a draw of funds) of any security instruments, and other related documents, used by Seller to establish and maintain the Security Fund pursuant to Seller's obligations under this Section.

11.2 Subordinated Mortgage.

(A) Prior to breaking ground for the Facility, Seller shall execute and deliver to Company a mortgage on the Facility and Facility Property, a security agreement with respect to Seller's licenses, permits, and contractual rights with respect to the ownership and operation of the Facility and Facility Property, to the extent assignable, and the equipment, fixtures and other personal property located or to be located on the Facility Property and/or principally related to Seller's operations on the Facility Property (collectively, the "Mortgaged Property"), associated financing statements, and other agreements, documents and instruments, in form and substance reasonably satisfactory to Company, Seller and, to the extent there is Facility Debt, the Facility Lender, under which Company shall enjoy a fully perfected security interest(s) and mortgage lien (collectively, the "Subordinated Mortgage") in the Mortgaged Property; *provided, however, that* the Mortgaged Property shall not include Seller's cash, accounts, securities, books and records, as more specifically described in the Subordinated Mortgage. Company agrees to cooperate with Seller and diligently negotiate, at Seller's request, the form of the Subordinated Mortgage and to execute and deliver the Subordinated Mortgage as reasonably necessary. The Subordinated Mortgage shall secure Seller's continuing performance under this PPA

and any amounts that may be owed by Seller to Company pursuant to this PPA, including, without limitation, any damages expressly excluded from the limitation on Seller's liability set forth in Section 12.3(C). To the extent there is Facility Debt, Seller agrees to, and Company shall, cause the Subordinated Mortgage to be subordinate in right of payment, priority, and remedies to the interests of the Facility Lender in the Facility Debt in accordance with an intercreditor agreement in form and substance satisfactory to the Company and Facility Lender. The granting of the Subordinated Mortgage shall not be to the exclusion of, nor be construed to limit, the amount of any further claims, causes of action or other rights accruing to Company by reason of any breach by Seller of this PPA or the early termination of this PPA as provided herein. In the event that there is no Facility Debt until later during the Term, (i) Company shall at such time subordinate the Subordinated Mortgage to such Facility Debt and take whatever actions may be requested by Seller and Facility Lender in connection therewith consistent with this Section 11.2(A) and (ii) Seller shall take such steps as may be reasonably required to ensure compliance with this Section 11.2(A). Company shall take such further actions and execute such further documents and instruments, all as reasonably required by Company, to confirm the subordination provisions set forth in this PPA.

(B) The Subordinated Mortgage shall be discharged and released, and Company shall take any steps reasonably required by Seller to effect and record such discharge and release, upon the expiration or earlier termination of the Term of this PPA and satisfaction by Seller of all obligations hereunder.

(C) Seller shall reimburse Company for the incremental direct expenses (including, without limitation, the reasonable fees and expenses of counsel) incurred by Company in connection with the preparation, negotiation, execution and/or the discharge and release of the Subordinated Mortgage and any related documents.

Article 12 - Default and Remedies

12.1 Events of Default. Any of the following events shall constitute an Event of Default of the specified Party on such date indicated or if such event has not been cured within the cure period specified for such event:

(A) Either Party's failure to make any undisputed payment to the other Party as required by this PPA, including invoices pursuant to Article 9, Liquidated Delay Damages, Actual Damages, any required indemnification, or any other required payment, and such amount remains unpaid for a period of ten (10) Business Days after the date the defaulting Party receives Notice from the non-defaulting Party that the amount is overdue.

(B) Either Party's application for, or consent (by admission of material allegations of a petition or otherwise) to, the appointment of a receiver, trustee or liquidator for a Party or for all or substantially all of its assets, or its authorization of such application or consent, or the commencement of any proceedings seeking such appointment against it without such authorization, consent or application, which

proceedings continue undismissed or unstayed for a period of sixty (60) Days from its inception.

(C) Either Party's inability to pay debts when due, authorization or filing of a voluntary petition in bankruptcy or application for or consent (by admission of material allegations of a petition or otherwise) to the application of any bankruptcy, reorganization, readjustment of debt, insolvency, dissolution, liquidation or other similar law of any jurisdiction or the institution of such proceedings against a Party without such authorization, application or consent, which proceedings remain undismissed or unstayed for sixty (60) Days from its inception or which result in adjudication of bankruptcy or insolvency within such time.

(D) The authorization or filing of a petition in voluntary bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency act of any state by a Party (and, in the case of Seller, its parent or any other Affiliates of Seller) that could materially affect such Party's ability to perform its obligations hereunder, which proceedings remain undismissed or unstayed for sixty (60) Days, or which result in adjudication of bankruptcy or insolvency within such time

(E) Either Party's unauthorized assignment of this PPA or Change of Control, immediately upon its occurrence and without further notice from the non-defaulting Party.

(F) Any material representation or warranty made by a Party in this PPA that is proven to have been false in any material respect when made and such falsity shall remain unremedied for sixty (60) Days after Notice thereof has been provided to the defaulting Party (or, if only able to be remedied by performance, such longer period as may be reasonably required to effect such remedy, not to exceed an additional sixty (60) Days.

(G) Seller's failure to establish and maintain the Security Fund as and in the amounts required that remains uncured for ten (10) Business Days after Company provides Notice of Seller's failure.

(H) Seller's failure to achieve the Commercial Operation Milestone.

(I) Seller's failure, commencing eighteen (18) months after the COD, to maintain a RAF, pursuant to Section 8.1, greater than **[Trade Secret Data Begins... ..Trade Secret Data Ends]** on a twelve-month rolling average basis utilizing data from the previous twelve months, if such failure shall remain unremedied for sixty (60) Days after Notice thereof has been provided to Seller; *provided, however, that* to the extent such failure of performance is attributable to Force Majeure, the contribution of such Force Majeure shall be eliminated from the RAF calculation for the purposes of, and only for the purposes of, establishing a default of Seller pursuant to this paragraph; *provided, further, that* if Seller provides a written opinion from an independent engineer retained and paid for by Seller and

approved by Company such failure was due to a Major Equipment Failure and Seller is diligently pursuing remedy of such Major Equipment Failure, Seller shall have an additional twelve (12) months following delivery of such opinion to Company to remedy such failure.

(J) Seller's material breach of the Interconnection Agreement that has a Material Adverse Effect on Company if such breach shall remain unremedied for thirty (30) Days after Notice thereof has been provided to Seller (or, if only able to be remedied by performance, such longer period as may be reasonably required to effect such remedy, not to exceed an additional sixty (60) Days).

(K) The failure by either Party to perform or observe any other material obligation to the other Party under this PPA, that is not excused by Force Majeure and such failure shall remain unremedied for thirty (30) Days after Notice thereof shall have been given by the non-defaulting Party (or, if only able to be remedied by performance, such longer period as may be reasonably required to effect such remedy, not to exceed an additional thirty (30) Days).

12.2 Remedies. Upon the occurrence of any Event of Default of this PPA, the non-defaulting Party may pursue all rights and remedies available to it at law and in accordance with the terms of this PPA. Except as explicitly provided to the contrary in this PPA, each right or remedy of the Parties provided for in this PPA shall be cumulative of and shall be in addition to every other right or remedy provided for in this PPA, and the exercise of one or more of the rights or remedies provided for herein shall not preclude the simultaneous or later exercise by such Party of any other rights or remedies provided for herein.

(A) Termination and Damages. The Parties agree that any uncured Event of Default is deemed to be material and justifies termination. For any uncured Event of Default, the non-defaulting Party may, at its option do any, some, or all of the following:

1. Offset from any payments due from the non-defaulting Party any amount otherwise due, including any unpaid Liquidated Delay Damages or Actual Damages;
2. Seek Actual Damages in such amounts and on such basis for the default as authorized by this PPA;
3. In the case of an Event of Default by Seller, draw on the Security Fund for any unpaid Liquidated Delay Damages, Actual Damages, required payments under Section 10.6, or any other required and unpaid amount;
4. In the case of an Event of Default by Seller, exercise of Company's Step-In Rights.
5. Terminate this PPA immediately upon Notice, without penalty or further obligation to the defaulting Party. Upon the termination of this PPA under this Section, the non-defaulting Party shall be entitled to receive from the

defaulting Party, subject to the Damage Caps, all of the Liquidated Delay Damages owed hereunder and any Actual Damages in connection with the Event of Default resulting in such termination.

(B) Liquidated Delay Damages. Seller shall be liable to pay Company Liquidated Delay Damages as a liquidated damage and not a penalty for any delay in meeting the Commercial Operation Milestone on the terms and conditions as follows:

1. Provided Seller actually pays Liquidated Delay Damages as and when owed, (i) the payment of such Liquidated Delay Damages shall be Company's sole and exclusive remedy for Seller's failure to achieve, or Seller's delay in achieving, the Commercial Operation Milestone, and (ii) Company shall have no right to seek Actual Damages, terminate this PPA, seek specific performance, or exercise its Step-In Rights, notwithstanding anything to the contrary in this Article 12. Liquidated Delay Damages shall be payable in lieu of Actual Damages accrued for the period during which Liquidated Delay Damages are assessed. The Parties specifically recognize that Company's damages associated with any delays in achieving the Commercial Operation Milestone will be significant but that it will be difficult to quantify those damages. If Seller does not pay Liquidated Delay Damages as and when owed, Company shall have the right to exercise all remedies available for an Event of Default under Section 12.2(A).

2. All Liquidated Delay Damages shall begin to accrue on the Day after the Commercial Operation Milestone as may be extended pursuant to this PPA until but excluding the Day upon which the Commercial Operation Date is achieved.

3. For avoidance of doubt, Seller's failure to obtain accreditation of the Facility as a Capacity Resource is not subject to Liquidated Delay Damages but rather subject to the default, cure, and damage provisions of Section 10.6.

(C) Actual Damages. For all Events of Default under Section 10.6 and this Section, except for a Failure to Meet Accreditation Deadline that is cured as specified in Section 10.6(C)1 or the failure to achieve the Commercial Operation Milestone for which Seller is paying Liquidated Damages as and when owed pursuant to Section 12.2(B)1, the non-defaulting Party shall be entitled to receive from the defaulting Party Actual Damages incurred by the non-defaulting Party; *provided, however, that* if such an Event of Default has occurred and has continued uncured for a period of 365 Days, the non-defaulting Party shall be required to either waive its right to collect further damages on account of such Event of Default, event, or breach or elect to terminate this PPA. If Seller is the defaulting Party, the Parties agree that Actual Damages recoverable by Company hereunder on account of an Event of Default of Seller may include Replacement Power Costs. If Company is the defaulting Party, the Parties agree that Actual Damages may include any direct damages available under this PPA.

(D) Specific Performance. In addition to the other remedies specified in this Article 12, in the event that any Event of Default of Seller is not cured within the applicable cure period set forth herein, Company may elect to treat this PPA as being in full force and effect and shall have the right to specific performance. By way of example only, if the breach by Seller arises from a failure by third party operating the Facility pursuant to an operating agreement entered into with Seller, and Seller fails or refuses to enforce its rights under the operating agreement that would result in the cure, or partial cure, of the Event of Default, Company's right to specific performance shall include the right to obtain an order compelling Seller to enforce its rights under the operating agreement.

12.3 Limitation on Damages.

(A) Except as otherwise provided in this Section, (i) Seller's aggregate financial liability to Company for Liquidated Delay Damages and any other pre-COD Actual Damages shall not exceed the Pre-COD Damage Cap, and (ii) Seller's aggregate financial liability to Company for Actual Damages post-COD shall not exceed the Post-COD Damage Cap (collectively the "Damage Cap(s)").

(B) If at any time during the Term, Company incurs damages under this PPA in excess of a Damage Cap that Seller does not agree to pay when billed by Company, Company shall have the right to terminate this PPA upon Notice.

(C) The Damage Caps shall not apply to Actual Damages arising out of any of the following events:

1. Physical damage to Company-owned facilities caused by Seller's gross negligence or willful misconduct;
2. Seller's intentional misrepresentation or willful misconduct in connection with this PPA or the operation of the Facility;
3. The sale or diversion by Seller to a third party of any capacity or energy committed to Company under this PPA other than as permitted under this PPA;
4. Seller's failure (i) to maintain insurance coverages in the types and amounts required by this PPA or (ii) to apply any insurance proceeds to restoration of damaged equipment of the Facility following a casualty except to the extent allowed by this PPA;
5. Any third party claim subject to indemnification under this PPA;
6. Any Environmental Contamination caused by Seller in connection with this PPA; or
7. Damages incurred by Company in connection with any bankruptcy or insolvency proceeding involving Seller, including Company's loss of the

benefit of its bargain due to rejection or other termination of this PPA in such proceeding.

(D) The Parties confirm that the express remedies and measures of damages provided in this PPA satisfy the essential purposes hereof. If no remedy or measure of damages is expressly herein provided, the obligor's liability shall be limited to Actual Damages only. Neither Party shall be liable to the other Party for consequential, incidental, punitive, exemplary, special, equitable or indirect damages, lost profits or other business interruption damages by statute, in tort or contract (except to the extent expressly provided herein); *provided, however, that* if either Party is held liable to a third party for such damages and the Party held liable for such damages is entitled to indemnification from the other Party hereto, the indemnifying Party shall be liable for, and obligated to reimburse the indemnified Party for, such damages. To the extent any damages required to be paid hereunder are liquidated, the Parties acknowledge that the damages are difficult or impossible to determine, that otherwise obtaining an adequate remedy is inconvenient, and that the liquidated damages constitute a reasonable approximation of the harm or loss.

12.4 Step-In Rights.

(A) Upon the occurrence of an Event of Default, Company shall have the right, but not the obligation, to exercise its Step-In Rights for the period of time until Seller has cured its Event of Default or this PPA has been terminated. Exercising Step-In Rights shall not preclude or limit Company's right to exercise any remedy it has against Seller under this PPA.

(B) Seller irrevocably appoints Company as Seller's attorney-in-fact for the exclusive purpose of executing such documents and taking such other actions necessary to implement Company's Step-In Rights. Seller shall not grant any person, other than the Facility Lender, a right to possess, assume control of, or operate the Facility in derogation of Company's Step-In Rights.

(C) Company acknowledges that the Facility Lender may foreclose and take possession of and operate the Facility and Company may be required to relinquish its Step-In Rights in such circumstance. Prior to commencing construction of the Facility, in the event there is Facility Debt, Seller shall obtain the written agreement of the Facility Lender recognizing Company's Step-In Rights as being limited only by foreclosure of the Facility as a result of Seller's material default of its contractual obligations with the Facility Lender.

(D) Company shall implement its Step-In Rights in conformance with Good Utility Practice and shall perform Seller's obligations in a manner consistent with Seller's duties under this PPA. Company shall indemnify Seller for any liabilities, losses, costs expenses and/or damages to Seller or the Facility to the extent such liabilities, losses, costs expenses and/or damages arise from Company's gross negligence or willful misconduct. Except to the extent such expenses and costs relate to Company's indemnification obligations to Seller in this Section 12.4(D), Seller shall reimburse Company for its expenses and costs (including the fees and expenses of

counsel) incurred by Company in connection with exercising its Step-In Rights. Company shall give Seller and, to the extent applicable, the Facility Lender 10 Days Notice in advance of exercising Company's Step-In Rights. Upon receipt of such Notice:

1. Seller shall make available at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Good Utility Practice.

2. Seller shall give Company, its employees, contractors, or designated third parties unrestricted access to the Site and the Facility.

3. Seller shall cooperate in the implementation of Company's Step-In Rights.

4. Company shall use the output generated and delivered from the Facility during such period in partial satisfaction of Seller's obligations hereunder.

(E) Company may draw upon the Security Fund to cover any expenses incurred by Company in exercising its rights under this Section.

(F) Seller shall retain legal title to and ownership of the Facility.

(G) Company shall timely pay to Seller all amounts that would otherwise be due to Seller under this PPA for products and services delivered to Company in accordance with this PPA.

(H) Company shall provide Seller with at least 15 Days Notice of Company's intent to relinquish its Step-In Rights. Company shall relinquish its Step-In Rights on the earliest of (i) termination of this PPA; (ii) Seller has cured all outstanding defaults; (iii) Company's unilateral decision to relinquish possession of the Facility; or (iv) the Parties mutual decision.

(I) Company's Step-In Rights shall not constitute an assumption by Company of any liability attributable to Seller.

12.5 Duty to Mitigate. Each Party agrees that it has a duty to mitigate damages and covenants that it will use Commercially Reasonable Efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of the PPA.

Article 13 - Dispute Resolution

13.1 Dispute Resolution

(A) In the event of any dispute arising under this PPA (a "Dispute"), within 10 Business Days following Notice by either Party, (i) each Party shall appoint a representative, and (ii) the representatives shall meet, negotiate and attempt in good faith to resolve the Dispute quickly, informally and inexpensively. In the event the

representatives cannot resolve the Dispute within 30 Days after the first meeting, either Party may request that consideration and resolution of the Dispute be transferred to a designated representative of each Party's senior management. Within 10 Days following such a request, each Party shall submit a written summary of the Dispute describing the issues and claims to a senior officer of each Party designated to address the Dispute. Within 10 Business Days after receipt of each Party's Dispute summaries, the senior management representatives for both Parties shall meet and negotiate in good faith to resolve the Dispute. If such senior management representatives are unable to resolve the Dispute within 30 Days after their first meeting, either Party may seek available legal remedies.

(B) If no Notice has been issued within 24 months following the occurrence of events or circumstances giving rise to the Dispute (regardless of the knowledge or potential knowledge of either Party of such events and circumstances), the Dispute and all claims related thereto shall be deemed waived and the aggrieved Party shall thereafter be barred from proceeding thereon.

(C) Seller and Company each hereby knowingly, voluntarily and intentionally waive any rights they may have to a trial by jury in respect of any litigation based hereon, or arising out of, under, or in connection with, this PPA or any course of conduct, course of dealing, statements (whether oral or written) or actions of Seller and Company related hereto and expressly agree to have any disputes arising under or in connection with this PPA be adjudicated by a judge of the court having jurisdiction without a jury.

Article 14 - Force Majeure

14.1 Applicability of Force Majeure. A Party shall be relieved of its obligations to perform this PPA and shall not be considered to be in default with respect to any obligation under this PPA if, and to the extent such Party is prevented from fulfilling such obligation by Force Majeure, *provided, however, that:* (i) such Party gives prompt Notice describing the circumstances and impact of the Force Majeure; (ii) the relief from its obligations sought by such Party is of no greater scope and of no longer duration than is required by the Force Majeure; (iii) such Party proceeds with Commercially Reasonable due diligence to overcome the Force Majeure and resume performance of its obligations under this PPA; and (iv) such Party provides Notice prior to the conclusion of the Force Majeure.

14.2 Limitations on Effect of Force Majeure.

(A) Force Majeure shall only relieve a Party of such obligations as are actually precluded by the Force Majeure.

(B) In no event will the existence of Force Majeure extend this PPA beyond its stated Term.

(C) In no event shall the existence of a claim of Force Majeure by Seller relieve Seller of its obligations under Section 10.6.

(D) If Force Majeure affecting a Party continues for an uninterrupted period of 90 Days from its inception (with respect to Force Majeure occurring prior to COD) or 365 Days from its inception (with respect to Force Majeure occurring after COD), the other Party may, at any time following the end of such period terminate this PPA upon Notice to the Party so affected, without further obligation by either Party except as to costs and balances incurred pursuant to this PPA prior to the effective date of such termination; *provided, however, that* if Seller within the first 90 Days of an uninterrupted Force Majeure event occurring prior to COD provides a written opinion from an independent engineer retained and paid for by Seller and approved by Company that the Force Majeure can be remedied within an additional 90 Days, then only after an uninterrupted period of 180 Days of a Force Majeure event affecting Seller may Company terminate the PPA under this Section.

14.3 Delays Attributable to Company. Seller shall be excused from performing its obligations under this PPA where Seller can establish that such a failure was caused by (i) any delay or failure by Company to perform its obligations under this PPA, or (ii) any delay or failure by the Transmission Authority to perform its obligations under the Interconnection Agreement, in each case whether or not caused by Force Majeure.

Article 15 - Representations and Warranties

15.1 General Representations and Warranties. Except for the requirements of Article 6 which the Parties will use their Commercially Reasonable Efforts to obtain, each Party hereby represents and warrants to the other as follows:

(A) It is a valid separate legal entity, duly organized, validly existing and in good standing under Applicable Law. It is qualified to do business in the State in which the Facility is located and each other jurisdiction where the failure to so qualify would have a Material Adverse Effect on the business or financial condition of the other Party; it has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The Party's execution, delivery, and performance of all of its obligations under this PPA have been duly authorized by all necessary corporate action, and do not and will not:

1. require any consent or approval by any governing corporate or management body, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to the other Party upon its request);

2. violate any Applicable Law, or violate any provision in any formation documents, the violation of which could have a Material Adverse Effect on the representing Party's ability to perform its obligations under this PPA;

3. result in a breach or constitute a default under the representing Party's formation documents or bylaws, or under any agreement relating

to its management or affairs or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which it is a party or by which it or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a Material Adverse Effect on the representing Party's ability to perform its obligations under this PPA; or

4. result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of the representing Party now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a Material Adverse Effect on the representing Party's ability to perform its obligations under this PPA.

(C) This PPA is a valid and binding obligation of the representing Party.

(D) The execution and performance of this PPA will not conflict with or constitute a breach or default under any contract or agreement of any kind to which the representing Party is a party or any judgment, order, or Applicable Law, applicable to it or its business.

(E) Within the meaning of the United States bankruptcy code, (i) this PPA constitutes a "master netting agreement", (ii) all transactions pursuant to this PPA constitute "forward contracts", (iii) the representing Party is a "forward contract merchant" and "master netting agreement participant", and (iv) all payments made or to be made pursuant to this PPA constitute "settlement payments."

(F) It is (i) an "eligible contract participant" as defined in Section 1a(18) of the Commodity Exchange Act, as amended, 7 U.S.C. § 1a(12), (ii) a "market participant" under applicable exchange and market rules; (iii) a producer, processor, or commercial user of, or a merchant handling, the commodity which is the subject of this PPA, or the products or by products thereof; and (iv) entering into this PPA solely for purposes related to its business as such.

(G) This PPA grants each Party the contractual right to "cause the liquidation, termination or acceleration" of the transactions within the meaning of Section 556, 560 and 561 of the bankruptcy code, as they may be amended superseded or replaced from time to time. Upon a bankruptcy, a non-defaulting Party shall be entitled to exercise its rights and remedies under this PPA in accordance with the safe harbor provisions of the bankruptcy code set forth in, inter alia, Sections 362(b)(6), 362(b)(17), 362(b)(27), 362(o), 546(e), 548(d)(2), 556, 560 and 561, as they may be amended superseded or replaced from time to time.

(H) Each Party is a commercial market participant that regularly makes or takes delivery of the commodity which is the subject of this PPA in connection with the ordinary course of its business, and who intends to make or take delivery, as applicable, of the commodity under the terms and conditions of this PPA in connection with such business.

(I) This PPA creates a binding obligation for each Party to either make or take delivery of the commodity which is the subject of this PPA, as applicable, without providing any right to offset, cancel, or settle such delivery obligations on a payment-of-difference basis.

15.2 Seller's Specific Representation. To the knowledge of Seller, and except for (i) Seller's CPs in Section 6.2 and (ii) any actions required by the Transmission Authority to qualify the Facility as a Capacity Resource, all actions required by any Governmental Authority to authorize Seller's execution, delivery and performance of this PPA have been duly obtained and are in full force and effect.

15.3 Company's Specific Representation. To the knowledge of Company, and except for the State Regulatory Approval identified in Section 6.1, all approvals, authorizations, consents, or other action required by any Governmental Authority to authorize Company's execution, delivery and performance of this PPA, have been duly obtained and are in full force and effect.

Article 16 - Insurance

16.1 Evidence of Insurance. No later than commencement of construction of the Facility and then on or before the policy renewal date each year thereafter during the Term, Seller shall provide Company with two (2) copies of insurance certificate(s) evidencing that insurance coverages for the Facility are in compliance with the specifications for insurance coverage set forth in Exhibit E-Insurance Coverage. Such certificates shall (a) name Company as an additional insured to the extent of the indemnity obligations assumed by Seller hereunder (except worker's compensation); (b) provide Company 30 Days prior Notice of non-renewal, cancellation of, or significant modification to any of the corresponding policies (except that such Notice shall be 10 Days for non-payment of premiums); (c) provide a waiver of any rights of subrogation against Company, its Affiliates and their officers, directors, agents, subcontractors, and employees; and (c) indicate that the Commercial General Liability policy has been endorsed as described above. All policies shall be written with insurers with an AM Best rating of at least A-VII or a Standard & Poor's rating of at least A, or that the Company deems acceptable. All policies shall be written on an occurrence basis, except as provided in Section 16.2. All policies shall contain an endorsement that Seller's policy shall be primary in all instances regardless of like coverages, if any, carried by Company. Seller's liability under this PPA is not limited to the amount of insurance coverage required herein.

16.2 Term and Modification of Insurance.

(A) All insurance required under this PPA shall cover occurrences during the Term and for a period of two (2) years after the Term. In the event that any insurance as required herein is commercially available only on a "claims-made" basis, such insurance shall provide for a retroactive date not later than the date of this PPA and such insurance shall be maintained by Seller for a minimum of five (5) years after the Term.

(B) The Parties shall modify the insurance types and minimum limits specified in Exhibit E-Insurance Coverage from time to time during the Term in order to maintain Commercially Reasonable coverage amounts in the event that Good Utility Practices so require and Seller can obtain the modified insurance on Commercially Reasonable terms. Seller shall make Commercially Reasonable Efforts to obtain such modified insurance.

(C) If any insurance required to be maintained by Seller hereunder ceases to be available in the commercial insurance market on reasonable terms for electric generating plants of a type, geographic location and capacity comparable to the Facility, Seller shall provide Notice to Company, accompanied by a certificate from an independent insurance advisor of recognized national standing, certifying that such insurance is no longer so available. Upon receipt of such Notice, Seller shall use Commercially Reasonable Efforts to obtain other insurance that would provide comparable protection against the risk to be insured.

16.3 Application of Proceeds. Seller shall apply any insurance proceeds to reconstruction of the Facility following a casualty.

Article 17 - Indemnity

17.1 Indemnification. Each Party (the "Indemnifying Party") agrees to indemnify, defend and hold harmless the other Party (the "Indemnified Party") from and against (a) all third party claims, demands, losses, liabilities, penalties, and expenses (including attorneys' fees) for personal injury or death to persons and (b) damage to the Indemnified Party's real property and tangible personal property or facilities or the property of any other person or entity to the extent arising out of, resulting from, or caused by the (i) an Event of Default or other breach under this PPA, (ii) violation of Applicable Laws, (iii) negligent or tortious acts, errors, or omissions, or (iv) intentional acts or willful misconduct, of the Indemnifying Party, its Affiliates, its directors, officers, employees, or agents.

(A) This indemnification obligation shall apply notwithstanding any negligent or intentional acts, errors or omissions of the Indemnified Party, but the Indemnifying Party's liability to indemnify the Indemnified Party shall be reduced in proportion to the percentage by which the Indemnified Party's negligent or intentional acts, errors or omissions caused the damages.

(B) Neither Party shall be indemnified for its damages resulting from its sole negligence, intentional acts or willful misconduct. These indemnity provisions shall not be construed to relieve any insurer of its obligation to pay claims consistent with the provisions of a valid insurance policy.

(C) Nothing in this Section shall enlarge or relieve Seller or Company of any liability to the other for any breach of this PPA.

17.2 Notice of Claim. Promptly after receipt by a Party of any claim or notice of the commencement of any action, administrative, or legal proceeding, or

investigation as to which the indemnity provided for in this Article may apply, the Indemnified Party shall send Notice thereof to the Indemnifying Party. The Indemnifying Party shall assume the defense thereof with counsel designated by such Party and satisfactory to the Indemnified Party, *provided, however, that* if the defendants in any such action include both the Indemnified Party and the Indemnifying Party and the Indemnified Party shall have reasonably concluded that there may be legal defenses available to it which are different from or additional to, or inconsistent with, those available to the Indemnifying Party, the Indemnified Party shall have the right to select and be represented by separate counsel, at the Indemnifying Party's expense, unless a liability insurer is willing to pay such costs.

17.3 Settlement of Claim. If the Indemnifying Party fails to assume the defense of a claim meriting indemnification, the Indemnified Party may at the expense of the Indemnifying Party contest, settle, or pay such claim, *provided, however, that* settlement or full payment of any such claim may be made only following consent of the Indemnifying Party or, absent such consent, written opinion of the Indemnified Party's counsel that such claim is meritorious or warrants settlement.

17.4 Amounts Owed. Except as otherwise provided in this Article, in the event that a Party is obligated to indemnify and hold the other Party and its successors and assigns harmless under this Article, the amount owing to the Indemnified Party will be the amount of the Indemnified Party's actual loss net of any insurance proceeds received by the Indemnified Party following a Commercially Reasonable effort by the Indemnified Party to obtain such insurance proceeds.

Article 18 - Lender Provisions

18.1 Accommodation of Facility Lender. Company shall make Commercially Reasonable Efforts to provide such consents to collateral assignment, certifications, representations, information or other documents, as may be reasonably requested by Seller in connection with the financing of the Facility consistent with the terms set forth in Exhibit I-Lender Consent Provisions (generally, a "Lender Consent"), *provided, however, that* in providing a Lender Consent, Company shall have no obligation to alter or modify the terms of this PPA or provide any consent or enter into any agreement, that has a Material Adverse Effect on any of Company's rights, benefits, risks, or obligations under this PPA. Seller shall reimburse, or shall cause the Facility Lender to reimburse, Company for the direct expenses (including the fees and expenses of counsel) incurred by Company in the preparation, negotiation, execution and/or delivery of the Lender Consent and any documents requested by Seller or the Facility Lender, and provided by Company, pursuant to this Section.

18.2 Facility Lender Notice and Right to Cure. Seller shall provide Company with a Notice identifying the Facility Lender and providing appropriate contact information for the Facility Lender. Following receipt of such Notice, Company shall provide Notice of any breach or default of Seller to the Facility Lender, and Company will accept a cure performed by the Facility Lender, so long as the cure is accomplished within the applicable cure period set forth in this PPA or such other

period as may be specified in a consent to assignment or other agreement between Company and the Facility Lender.

18.3 Notice of Facility Lender Action. Within 10 Days following Seller's receipt of each Notice from the Facility Lender of default, or Facility Lender's intent to exercise any remedies under the Financing Documents, Seller shall deliver a copy of such Notice to Company.

18.4 Officer Certificates. Each Party shall deliver or cause to be delivered to the other Party certificates of its officers, accountants, engineers or agents as to matters as may be reasonably requested, and shall make available personnel and records relating to the Facility to the extent that the requesting Party requires the same in order to fulfill any regulatory reporting requirements, or to assist the requesting Party in litigation, including administrative proceedings before utility regulatory commissions.

Article 19 - Assignment and Other Transfer Restrictions

19.1 Transfer Without Consent is Null and Void. Any Change of Control or sale, transfer, or assignment of any interest in the Facility or in this PPA made without fulfilling the requirements of this PPA shall be null and void and a breach of this PPA.

(A) Except as permitted in this Section, neither Party shall assign this PPA or any portion thereof, without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed; *provided, however, that* (i) at least 30 Days prior Notice of any proposed assignment requiring consent shall be given to the other Party; (ii) any assignee shall expressly assume the assignor's obligations under this PPA unless otherwise agreed by the other Party, (iii) except as otherwise provided in Sections 19.1(A)1 and 19.1(A)3, no assignment shall relieve the assignor of its obligations under this PPA in the event the assignee fails to perform, unless the other Party waives in writing the assignor's continuing obligations under this PPA; (iv) no assignment shall impair any security given by Seller unless such security has been replaced in accordance with Section 11.1; and (v) before this PPA is assigned by Seller, the assignee must first obtain such approvals as may be required by all applicable Governmental Authorities.

1. Seller's consent shall not be required for Company to assign this PPA to an Affiliate of Company; *provided, however, that* Company shall remain liable for obligations incurred under this PPA unless released in accordance with the terms of this PPA. In the event that a permitted assignee of Company is an entity that provides retail electric service in the State in which the Facility is located and is subject to rate and quality service regulation under the jurisdiction of the MPUC and has an Investment Grade rating, Seller shall release Company from its obligations under this PPA if Company requests to be so released by Notice to Seller.

2. Company's consent shall not be required for Seller to assign this PPA for collateral purposes, to the Facility Lender. Seller shall provide Company Notice of any such assignment no later than 30 Days after the assignment.

3. Company's consent shall not be required for Seller to assign this PPA to MEC I if, as of the date of assignment, MEC I (i) owns all or substantially all of the Facility and the Facility Property, (ii) assumes Seller's obligations under this PPA, and (iii) has the technical expertise substantially similar to Seller to perform Seller's obligations under this PPA.

4. Company shall release Seller from its obligations under this PPA, upon request of Seller, in the event of any permitted assignment of this PPA by Seller to any assignee that: (a) is Investment Grade rated or has a parent that is Investment Grade rated; (b) provides a Security Fund meeting the requirements of Section 11.1; (c) assumes Seller's obligations under this PPA; and (d) has technical expertise (or has retained others with such expertise) substantially similar to Seller to perform Seller's obligations under this PPA as of the date of assignment.

(B) Any Change of Control of Seller, whether voluntary or by operation of law, shall require the prior written consent of Company, which shall not be unreasonably withheld, *provided, however, that* no such consent shall be required for any Change of Control of Seller if the ultimate parent entity of Seller following the Change of Control, together with its Affiliates, has an Investment Grade rating as measured by its senior unsecured credit rating unenhanced by third party support (or enjoys creditworthiness if such credit rating is unavailable as otherwise reasonably determined by Company) not worse than Seller's ultimate parent entity, together with its Affiliates, prior to the Change of Control.

(C) For the avoidance of doubt, the Parties acknowledge and agree that Seller shall not be relieved of its obligations under this PPA as the result of any Change of Control unless Company agrees in writing in advance to waive Seller's continuing obligations under this PPA.

19.2 ROFO.

(A) At any time after the Commercial Operation Date, if Seller or any Affiliate of Seller decides to solicit or proceed with unsolicited third-party offers to convey all or substantially all of the Facility Property and the assets comprising the MEC I Facility or a majority of the interests in Seller and MEC I (each a "Proposed Transaction") to an unaffiliated third party, Seller shall in advance of any such solicitation or pursuit of unsolicited offers provide Company with the right of first offer ("ROFO"). Under the ROFO, Seller shall furnish to Company (i) the terms Seller is willing to accept in connection with the Proposed Transaction, and (ii) the price Seller is willing to accept to proceed with the Proposed Transaction (the "ROFO Notice"). Company's ROFO shall only apply to a Proposed Transaction and its related terms and conditions where the conveyance of all or substantially all of the Facility Property and the assets comprising the MEC I Facility or majority of the interests in Seller and

MEC I represents substantially all of the value of the assets or interests, as applicable, being conveyed in such Proposed Transaction. .

(B) Seller shall allow Company (a) where Seller has elected to solicit third party offers, forty-five (45) Days after the ROFO Notice to investigate the Proposed Transaction and conduct due diligence, (b) where Seller has elected to pursue unsolicited third party offers, thirty (30) Days after the ROFO Notice to investigate the Proposed Transaction and conduct due diligence. Within the applicable period, Company shall either (i) exercise its ROFO rights on terms equivalent to the terms and price set forth in the ROFO Notice or (ii) cancel its ROFO rights.

1. If Company exercises its ROFO, the Parties shall have a period of no longer than six (6) months to conduct due diligence and develop definitive agreements on terms no less favorable to Company than those contained in the ROFO Notice. Seller shall cooperate in all respects necessary for Company to exercise its ROFO rights.

2. If Company does not exercise its ROFO, Seller shall have the right to solicit offers on the Proposed Transaction from unaffiliated third, *provided, however, that* in the event Seller proceeds with the Proposed Transaction and the purchaser is an unaffiliated third party, (a) the price associated with such transaction shall have an aggregate value of not less than the price set forth in the ROFO Notice, and (b) the terms associated with such transaction shall be no less favorable to Seller than the terms set forth in the ROFO Notice. In the event Seller does not close on its Proposed Transaction with an unaffiliated third party, Seller shall offer Company a ROFO in connection with any new or subsequent Proposed Transaction as set forth in Section 19.2(B).

(C) In the event that: (a) a Proposed Transaction is part of a larger transaction to which Company's ROFO does not apply and (b) such Proposed Transaction represents more than twenty percent (20%) of the aggregate generating capacity that would be conveyed by such larger transaction, Seller shall provide Notice to Company of its decision to solicit or proceed with the Proposed Transaction within thirty (30) Days of such decision, and Company may in its sole discretion make an offer for Seller's consideration to purchase all or substantially all of the Facility Property and the assets comprising the MEC I Facility or a majority of the interests in Seller and the MEC I the Facility upon receipt of such Notice.

19.3 Subcontracting. Seller may subcontract its duties or obligations under this PPA without the prior written consent of Company, *provided, however, that* no such subcontract shall relieve Seller of any of its duties or obligations hereunder.

Article 20 - Miscellaneous

20.1 Notices. Notices required by this PPA shall be in writing and addressed to the other Party, including the other Party's representative on the

Operating Committee, at the addresses noted in Exhibit D-Notices and Contact Information as either Party updates them from time to time by Notice to the other Party. Notices shall either be hand delivered or mailed, postage prepaid. If mailed, Notices shall be simultaneously sent by facsimile or other electronic means. Any Notice shall be deemed to have been received by the close of the Business Day on which it was hand delivered or transmitted electronically (unless hand delivered or transmitted after the close of the Business Day, in which case it shall be deemed received at the close of the next Business Day). Real-time or routine communications concerning Facility operations, including with respect to provision of energy from Alternate Energy Source(s), shall be exempt from this Section.

20.2 Taxes, Emissions and Change of Law.

(A) Seller shall be solely responsible for any and all present or future taxes and other impositions of Governmental Authorities relating to the construction, ownership or leasing, operation or maintenance of the Facility, or any components or appurtenances thereof, any sales or *ad valorem* taxes relating to the Facility, or any taxes on the products and services generated by Seller, sold and delivered to Company at the Point of Delivery. Seller's prices under Article 8 are inclusive of such taxes and impositions during the Term.

(B) Company shall be solely responsible for sales and use taxes imposed with respect to the purchase of fuel by Company for use in or consumption by the Facility to produce the electric energy dispatched and received by Company hereunder.

(C) The Parties shall cooperate to minimize and mitigate tax exposure, *provided, however, that* neither Party shall be obligated to incur any financial burden to reduce taxes for which the other Party is responsible hereunder. All electric energy delivered by Seller to Company hereunder shall be sales for resale, with Company reselling such electric energy. Company shall obtain and provide Seller with any certificates required by any Governmental Authority, or otherwise reasonably requested by Seller to evidence that the deliveries of electric energy hereunder are sales for resale.

(D) Notwithstanding clause (A) of this Section, Company shall be solely responsible for the payment of any taxes and other impositions enacted or promulgated by Governmental Authorities after the Effective Date, that are assessed based upon the quantity of carbon dioxide emissions produced from the combustion of fuel purchased by Company for consumption by the Facility to produce Contract Energy or Test Energy during the Term of this PPA.

1. If (i) following the Effective Date of this PPA, Applicable Law imposes any enforceable limits or other enforceable compliance obligations related to carbon dioxide emissions produced from the combustion of fuel by the Facility to produce Contract Energy or Test Energy, (ii) the limits or obligations are not imposed on a facility specific basis, and (iii) such limits or obligations can be mitigated

by the acquisition or application by Company of allowances, credits and/or eligible offsets, then (a) Company shall be responsible for compliance with the limits or compliance obligations from the Facility in its generation portfolio, and (b) Company shall be solely responsible for the acquisition costs, application and management of such allowances, credits and/or offsets necessary to mitigate carbon dioxide emissions produced from the combustion of fuel by the Facility to produce Contract Energy or Test Energy.

2. Nothing herein shall relieve Seller of its obligation to comply, at its sole cost, with Applicable Law or any Permit (including any emission limit or standard relating to carbon dioxide) imposed specifically on the Facility.

(E) With respect to any changes to Applicable Law with respect to emissions of carbon dioxide or other emissions, including SO_x and NO_x, enacted or promulgated by Governmental Authorities after the Effective Date that have or are reasonably likely to have a Material Adverse Effect on the economics of this PPA or the Facility with respect to either Party, the Parties will cooperate to consider a mutually agreeable and Commercially Reasonable response to mitigate such Material Adverse Effect.

20.3 Applicable Laws. Each Party shall at all times comply with all Applicable Laws, except for any non-compliance that, individually or in the aggregate, could not reasonably be expected to have a Material Adverse Effect on the business or financial condition of the Party or its ability to fulfill its commitments hereunder.

(A) As applicable, each Party shall give all required notices, shall procure and maintain all necessary governmental permits, licenses, and inspections necessary for performance of this PPA, and shall pay its respective charges and fees in connection therewith.

(B) Each Party shall promptly disclose to the other, any violation of any Applicable Laws arising out of or in connection with the Facility and this PPA.

(C) Upon permanent cessation of generation from the Facility, Seller shall decommission the Facility, remove the Facility and remediate the Site as, if and when required by Applicable Laws.

20.4 Fines and Penalties.

(A) Each Party shall pay when due all fees, fines, penalties or costs incurred by such Party or its agents, employees or contractors for noncompliance by such Party, its employees, or subcontractors with any provision of this PPA, or any contractual obligation, Permit or requirements of Applicable Law, except for such fines, penalties and costs that are being actively contested in good faith and with due diligence by such Party and for which adequate financial reserves have been set aside to pay such fines, penalties or costs in the event of an adverse determination.

(B) If fees, fines, penalties, or costs are claimed or assessed against a Party (“Aggrieved Party”) by any Governmental Authority due to noncompliance by the other Party, its employees, or subcontractors (“Offending Party”) with any provision of this PPA, or any contractual obligation, Permit or requirements of Applicable Law, or, if the performance of the Offending Party or any of its contractors or subcontractors is delayed or stopped by order of any Governmental Authority due to the Offending Party’s noncompliance with any provision of this PPA, or any contractual obligation, Permit or requirements of Applicable Law, the Offending Party shall reimburse and hold the Aggrieved Party harmless against any such costs incurred by the Aggrieved Party, including claims for indemnity or contribution made by third parties against the Aggrieved Party in accordance with Article 17.

20.5 Rate Changes.

(A) The terms and conditions and the rates for service specified in this PPA shall remain in effect for the term of the transaction described herein. Absent the Parties’ written agreement, this PPA shall not be subject to change by application of either Party pursuant to Section 205 or 206 of the Federal Power Act.

(B) Absent the agreement of all Parties to the proposed change, this PPA shall not be subject to change by application of either Party pursuant to Section 205 or 206 of the Federal Power Act. Absent the agreement of both Parties to the proposed change, the standard of review for changes to this PPA whether proposed by a Party, a non-party, or FERC acting *sua sponte* shall be the “public interest” standard of review set forth in *United Gas Pipe Line v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) (the Mobile-Sierra doctrine), as interpreted and applied by the Supreme Court of the United States in subsequent cases.

20.6 Disclaimer of Third Party Beneficiary Rights. In executing this PPA, Company does not and does not intend to extend its credit or financial support for the benefit of any third parties, or lending money to or having other transactions with Seller. Nothing in this PPA shall be construed to create any duty to, or standard of care with reference to, or any liability to, any person not a party to this PPA.

20.7 Relationship of the Parties.

(A) This PPA shall not be interpreted to create an association, joint venture, or partnership between the Parties nor to impose any partnership obligation or liability upon either Party. Except as specifically provided for in this PPA to the contrary, neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as an agent or representative of, the other Party.

(B) Each Party shall be solely liable for the payment of all wages, taxes, and other costs related to the employment of persons by such Party to perform such Party’s obligations under this PPA, including all federal, state, and local income,

social security, payroll, and employment taxes and statutorily mandated workers' compensation coverage. None of the persons employed by a Party shall be considered employees of the other Party for any purpose; nor shall a Party represent to any person that he or she is or shall become an employee of the other Party.

20.8 Equal Employment Opportunity Compliance Certification. Seller acknowledges that as a government contractor Company is subject to Applicable Laws regarding equal employment opportunity and affirmative action. Such Applicable Laws may also be applicable to Seller as a subcontractor to Company. All such Applicable Laws shall be deemed to be incorporated herein as required by Applicable Law, including 41 C.F.R. §60-1.4(a)(1-7).

20.9 Survival of Obligations. Cancellation, expiration, or earlier termination of this PPA shall not relieve the Parties of obligations, including warranties, remedies, or indemnities, that by their nature should survive such cancellation, expiration, or termination, which obligations shall survive for the period of the applicable statute(s) of limitation.

20.10 Severability. In the event any of the terms, covenants, or conditions of this PPA, its Exhibits, or the application of any such terms, covenants, or conditions, shall be held invalid, illegal, or unenforceable by any court or administrative body having jurisdiction, all other terms, covenants, and conditions of the PPA and their application not adversely affected thereby shall remain in force and effect; *provided, however, that* Company and Seller shall negotiate in good faith to attempt to implement an equitable adjustment in the provisions of this PPA with a view toward effecting the purposes of this PPA by replacing the provision that is held invalid, illegal, or unenforceable with a valid provision the economic effect of which comes as close as possible to that of the provision that has been found to be invalid, illegal or unenforceable.

20.11 Complete Agreement; Amendments. The terms and provisions contained in this PPA constitute the entire agreement between Company and Seller with respect to the Facility and shall supersede all previous communications, representations, or agreements, either verbal or written, between Company and Seller with respect to the sale of any output from the Facility. This PPA, including Exhibits, may be amended, changed, modified, or altered in accordance with the terms of this PPA, *provided, however, that* such amendment, change, modification, or alteration shall be in writing.

20.12 Binding Effect. This PPA is binding upon and shall inure to the benefit of the Parties hereto and their respective successors, legal representatives, and assigns.

20.13 Headings. Captions and headings used in this PPA are for ease of reference only and do not constitute a part of this PPA.

20.14 Counterparts. This PPA may be executed in counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

20.15 Governing Law. The interpretation and performance of this PPA and each of its provisions shall be governed and construed in accordance with the laws of the State in which the Facility is located, exclusive of conflict of laws principles. The Parties submit to the exclusive jurisdiction of the state courts of the State in which the Facility is located, and venue is hereby stipulated as the capital city of such State or such other city as mutually agreed to by the Parties.

20.16 Press Releases and Media Contact. Upon the request of either Party, the Parties shall develop a mutually agreed joint press release to be issued describing the location, size, type and timing of the Facility, the long-term nature of this PPA, and other relevant factual information about the relationship. In the event during the Term, either Party is contacted by the media concerning this PPA or the Facility, the contacted Party shall inform the other Party of the existence of the inquiry, any questions asked, and the substance of any information provided to the media.

20.17 Exhibits. Either Party may change the information in Exhibit D-Notices at any time by Notice without the approval of the other Party. All other Exhibits may be changed to the extent allowed by specific provisions of this PPA or with the mutual consent of both Parties.

20.18 Confidentiality.

(A) This PPA and all appendices and amendments hereto are intended to be treated as Confidential Information. Within thirty (30) Days from execution of this PPA, Seller shall provide the Company with its version of this PPA with all of Seller's claimed Confidential Information redacted. Within 30 Days of receipt, Company shall provide Seller its version of this PPA with all of Company's claimed Confidential Information as well as Seller's claimed Confidential Information redacted ("Confidential PPA Version"). A Party may provide this Confidential PPA Version to Governmental Authorities or their staffs in connection with any regulatory proceeding, including regulatory filings and responses to discovery requests, without consent from the other Party. Notice of a Party's disclosure of the Confidential PPA Version shall be provided to the other Party within 10 Days of such disclosure.

(B) The Parties acknowledge and agree that during the course of the performance of their respective obligations under this PPA, either Party may need to provide information to the other Party, which the disclosing party deems confidential, proprietary or a trade secret ("Confidential Information").

1. Confidential Information shall include all documentation and data, including special techniques, methods, computer programs and software that the disclosing Party considers proprietary or trade secret and furnishes to the receiving Party. Such materials may be designated as Confidential Information by clear and distinct notation on such documentation or by equivalent method, and shall be treated as such by the receiving Party. Documentation and data not so designated need not be considered by the receiving Party to be proprietary or trade secret; *provided, however, that* any and all data and documentation regarding Facility output,

performance, outages and similar operational information shall be considered Confidential Information without the need for further designation if any disclosure thereof would be in a form or by a means that associates such data or documentation with the Facility or Seller or any of its Affiliates, or from which a reasonable person could make such an association. The disclosing Party hereby grants to the receiving Party authority to use Confidential Information for the purposes of this PPA, including keeping electronic copies of such Confidential Information. The receiving Party agrees to keep such Confidential Information confidential, except as set forth in this Section, to use it for work necessary to the performance of this PPA, and not to sell, transfer, sublicense, disclose or otherwise make available any such Confidential Information to others; *provided, however, that* Confidential Information may be disclosed by the receiving Party to the agents, employees, advisors, consultants, or potential or actual debt or equity investors of the receiving Party (including in the case of Seller, Facility Lender), subject to their acceptance of the obligations of confidentiality imposed hereby and for whose violations of this requirement of confidentiality the receiving Party shall be responsible.

2. Confidential Information shall not include any data or information:

a. Which can be documented was in the public domain as allowed by this Section, or through no fault or action of the receiving Party at the time it was disclosed by the disclosing Party to the receiving Party or at any time thereafter;

b. Which can be documented was independently developed by the receiving Party;

c. Which can be documented was known to the receiving Party from an ultimate source other than the disclosing Party without breach of this PPA by the receiving Party;

d. Which is legally requested or required (by oral questions, interrogatories, requests for information or documents, subpoena, civil investigative demand or similar process or, in the opinion of its counsel, by Applicable Laws) to be disclosed, *provided, however, that* the Party requested or required to make a disclosure shall promptly notify the non-disclosing Party, no later than five Days of such request or requirement and prior to disclosure so that the non-disclosing Party may seek an appropriate protective order and/or waive compliance with the terms of this Section.

3. The obligation to maintain Confidential Information in confidence shall continue until two (2) years after the expiration or earlier termination of this PPA.

[remainder of this page intentionally left blank]

IN WITNESS WHEREOF, the Parties and MEC I have executed this PPA.

Seller:

By: _____

Company:

David M. Sparby
Senior Vice President & Group President,
Revenue
President & CEO, NSP Minnesota

By: _____

MEC I:

By: _____

EXHIBIT A

DEFINITIONS

The following terms shall have the meanings set forth herein:

“Acceptable Natural Gas Fuel” means (i) natural gas fuel procured from the Upstream Pipeline pursuant to the Upstream Pipeline’s tariff, which tariff includes the natural gas quality specifications, requirements, and minimum delivery pressures, as attached hereto as Exhibit K-Fuel Quality Specifications, or (ii) such other natural gas fuel delivered to a Fuel Delivery Point, the actual gas quality of which meets or exceeds the natural gas quality specifications, requirements and minimum delivery pressures in Exhibit K-Fuel Quality Specifications; or (iii) natural gas fuel that otherwise complies with the turbine manufacturer’s natural gas fuel quality specifications, requirements and delivery pressures and that would not otherwise void such manufacturer’s warranties.

“Accreditation Deadline” shall have the meaning set forth in Section 10.6(C).

“Accreditation Delay Notice” shall have the meaning set forth in Section 10.6(E).

“Actual Capacity” of the Facility means the actual (vs. tested) maximum net generating capability of the Facility from time to time, including capacity available from duct firing, unadjusted to Reference Conditions. Actual Capacity may be greater or less than the Net Capability of the Facility.

“Actual Damages” means direct damages proximately caused by an Event of Default.

“Actual Net Heat Rate” means the net heat rate for the Facility, stated in Btu/kWh, Higher Heat Value (“HHV”), as adjusted to Reference Conditions, resulting from a heat rate test conducted in accordance with Section 8.4.

“Affiliate” means any person or entity that directly or indirectly controls, is under the control of, or is under common control with, the named entity by the power to direct or cause the direction of the management of the policies of named entity, whether through ownership interest, by contract or otherwise.

“AGC” or “Automatic Generation Control” means the equipment and capability of an electric generation facility to automatically adjust the generation quantity within the applicable Balancing Authority with the purpose of interchange balancing and specifically, the Facility’s capability of accepting AGC Set-Point electronically and automatically adjusting and regulating the Facility’s energy production via the Facility’s SCADA System. For the Facility to be considered capable of AGC, it must meet the dispatchability requirements described in Section (A) of Exhibit H-Operating Standards.

“Aggrieved Party” shall have the meaning set forth in Section 20.4(B).

“Air Permit” means any permit or permit amendment required by the Minnesota Pollution Control Agency under Chapter 7007 of the Minnesota Rules for construction and operation of the Facility.

“Alternate Delivery Point” shall have the meaning set forth in Section 7.3.

“Alternate Generation Source” shall have the meaning set forth in Section 7.3.

“Ancillary Services” means those ancillary services defined under the Transmission Tariff as well as those other services and products that may be included under such tariff from time to time, which are associated, directly or indirectly, with the capacity of the Facility or the transmission of energy from the Facility.

“Applicable Law” means all laws, statutes, treaties, codes, ordinances, regulations, certificates, orders, licenses and permits of any Governmental Authority that are applicable to a Party, the business of a Party or the Facility, now in effect or hereafter enacted, amendments to or interpretations of any of the foregoing by a Governmental Authority having jurisdiction, and all applicable judicial, administrative, arbitration and regulatory decrees, judgments, injunctions, writs, orders, awards or like actions.

“Auction Clearing Price” means the price at which capacity credit can be purchased in the Transmission Authority’s market for such credit for the Facility’s location, which the Transmission Authority currently designates as Local Resource Zone 1.

“Availability Verification Test” shall have the meaning set forth in Section 10.1(B).

“Available Energy” shall have the meaning set forth in Section 8.1(A).

“Back-Up Metering” shall have the meaning set forth in Section 5.2(B).

“Balancing Authority” means the system of electrical generation, distribution and transmission facilities within which generation is regulated in order to maintain interchange schedules with other such systems.

“Base Capacity” means the portion of the Facility’s Actual Capacity, without duct firing.

“Breakage Fee” shall have the meaning set forth in 2.4(B).

“Btu” means British thermal unit.

“Business Day” means any Day that is not a Saturday, a Sunday, or a NERC recognized holiday.

“CAF” stands for Capacity Availability Factor and shall have the meaning set forth in Section 8.1.

“Capacity Resource” means the amount of net generating capacity associated with the Facility for which capacity credit may be obtained under the Transmission Authority’s planning reserve procedures and requirements.

“Change of Control” means the occurrence of any one of the following events with respect to Seller or any direct or indirect owner of a majority of the ownership interests in Seller if the direct or indirect interest in Seller represents substantially all of the value of such owner’s assets: (i) a transfer of a majority of the ownership interests in Seller or such owner; or (ii) any consolidation or merger of Seller or such owner in which Seller or such owner, as the case may be, is not the continuing or surviving entity, or (iii) a sale or conveyance of any direct or indirect ownership interest in Seller following which the selling entity or entities that formerly owned, directly or indirectly, a majority of the ownership interest in Seller no longer own such a majority, *provided, however, that* a Change of Control shall not be deemed to have occurred as a result of (i) transactions exclusively among Affiliates of Seller, (ii) any exercise by the Facility Lender of its rights and remedies under the Financing Documents, (iii) a change of the Ultimate Parent Entity of Seller (defined under Section 7A of the Clayton Act, 15 U.S.C. 18a, aka the Hart-Scott-Rodino Antitrust Improvements Act of 1976), or (iv) any change of economic and voting rights triggered in Seller’s organization documents arising from the financing of the Facility and that does not result in the transfer of ownership, economic or voting rights in any entity that had no such rights immediately prior to the change.

“COD Conditions” means all of the requirements that must be satisfied by Seller in order to achieve Commercial Operation as set forth in Section 4.3.

“Commercial Operation” means the period beginning on the Commercial Operation Date and continuing through the Term of this PPA.

“Commercial Operation Date” or “COD” means 12:01 am on the date following the date upon which Seller satisfies the COD Conditions, or such other date as is mutually agreed upon by the Parties.

“Commercial Operation Milestone” means the Construction Milestone specified in Exhibit B-Construction Milestones, as may be extended pursuant to the terms of this PPA, by which Seller must have satisfied the COD Conditions to achieve the Commercial Operation Date on the following Day .

“Commercial Operation Year” means any consecutive 12 month period during the Term, commencing with the Commercial Operation Date or any of its anniversaries.

“Commercially Reasonable” or “Commercially Reasonable Efforts” means, with respect to any action required to be made, attempted or taken by a Party under this PPA, the level of effort in light of the facts known to such Party at the time a decision is made that: (a) can reasonably be expected to accomplish the desired action at a reasonable cost; (b) is consistent with Good Utility Practices; and (c) takes into consideration the amount of advance notice required to take such action, the duration and type of action and the competitive environment in which such action occurs.

“Company” shall have the meaning set forth in the first paragraph of this PPA.

“Confidential Information” shall have the meaning set forth in Section 20.18.

“Construction Contract” means the contract or contracts providing for the engineering, procurement, construction, acquisition, manufacture, delivery and installation of the generating and step-up transformation equipment that is to be part of the Facility and the engineering, procurement and construction of the Facility.

“Construction Milestones” means the dates set forth in Exhibit B-Construction Milestones, as may be extended pursuant to the terms of this PPA.

“Contract Capacity” shall have the meaning set forth in Section 7.2(A).

“Contract Energy” shall have the meaning set forth in Section 8.3.

“Daily Gas Cost” for any Day, expressed in \$/MMBtu, means the sum of (i) the midpoint of the daily gas price survey for Northern, Ventura, as published for that Day by Platts Gas Daily (the “Gas Survey”), multiplied by the percentage fuel rate for the relevant delivering pipeline in effect for that Day, plus (ii) the applicable commodity transportation rate for the relevant delivering pipeline in effect for that Day, plus (iii) the midpoint of the daily gas price survey for Northern, Ventura, as published for that Day by Platts Gas Daily. If Platts Gas Daily ceases to publish the Gas Survey, or if the Gas Survey is changed so that it is intended to measure something materially different from the level of wholesale gas prices in the vicinity of the Site, the Parties shall substitute a new index that reasonably measures a comparable level of wholesale gas prices in the region.

“Damage Caps” shall have the meaning set forth in Section 12.3.

“Day” means a calendar day.

“Day-Ahead Market” shall have the meaning set forth in the Transmission Tariff.

“Deficiency” means the deficiency in Reported Availability and tested availability of the Facility as described in Section 10.1(B).

“Delay Option” shall have the meaning set forth in Section 2.3.

“Delay Period” shall have the meaning set forth in Section 2.3.

“Delivery and Supply Commencement Notice” shall have the meaning set forth in Section 10.6(B).

“Delivery and Supply Commencement Notice Effective Date” shall have the meaning set forth in Section 10.6(B).

“Demobilization Costs” shall have the meaning set forth in Section 2.3(A).

“Dispatchability Payment” shall have the meaning set forth in Section 8.2.

“Dispatchability Rate” means *[Trade Secret Data Begins...
...Trade Secret Data Ends]*.

“Dispute” shall have the meaning set forth in Article 13.

“Effective Date” shall have the meaning set forth in the introductory paragraph.

“Electric Metering Devices” means revenue quality meters, metering equipment and data processing equipment used to measure, record or transmit data relating to the output from the Facility, including the metering current transformers and the metering voltage transformers.

“Emergency” means any event or occurrence after the date of this PPA that results in the declaration of an Emergency Condition under and as defined in the Interconnection Agreement.

“Energy Markets Control Center” or “EMCC” means Company's merchant representatives responsible for dispatch of generating units, including the Facility.

“Energy Resource Interconnection Service” or “ERIS” shall have the meaning set forth in the Transmission Tariff.

“Environmental Assessments” shall have the meaning set forth in Section 4.1(A).

“Environmental Contamination” means the introduction or presence of Hazardous Materials at such levels, quantities or location, or of such form or character, as to constitute a violation of Applicable Law, and present a material risk under Applicable Laws that the Site will not be available or usable for the purposes contemplated by this PPA.

“ERO” means the Electric Reliability Organization certified by FERC pursuant to Section 215 of the Federal Power Act or any successor organization; the Midwest Reliability Organization (“MRO”) is the certified ERO as of the date of this PPA.

“ESC Event” shall mean those events described in Exhibit M-ESC Event Adjustment.

“ESC Event Adjustment” has the meaning set forth in Section 8.7.

“Event of Default” shall have the meanings set forth in Articles 10.6 and 12.

“Excused Outage” means a partial or complete outage of the Facility to the extent caused or extended by: (i) a breach of this PPA by Company; (ii) any disconnection of the Facility from the Transmission Authority's System not attributable to events or conditions at the Facility; (iii) an interruption in the supply of required House Power for the Facility, not attributable to the Facility, if the Facility is using the Company

distribution system for House Power; (iv) the Facility having reached the limits of the operating restrictions imposed by any Permits (or any subsequent amendments thereto) applicable to or affecting the Facility, *provided, however, that* if any Permit restriction results in the restriction of the amount of Contract Energy that is available for dispatch and receipt by Company to an amount which is less than the amount set forth in the original version of such Permit, then the Contract Capacity shall be considered unavailable to the extent that Seller cannot deliver Contract Energy to Company in an amount equal to such original amount; (v) modification of the Facility at Company's request pursuant to this PPA or otherwise; or (vi) Company's failure or inability to supply to a Fuel Point of Delivery sufficient Acceptable Natural Gas Fuel for operation of the Facility, whether due to Force Majeure or any other reason. Excused Outage does not include: (1) any disconnection of the Facility from the Transmission Authority's System attributable to events or conditions at the Facility except as described above; or (2) any event or condition of Force Majeure at the Site that affects the Availability of the Facility, not attributable to Company or events or conditions on the Company side of the Interconnection Point.

"Facility" means Seller's electric generating facilities, associated balance of plant, parts and equipment consistent with the warranties for the major equipment components, and all equipment necessary to interconnect such facilities to the Transmission Authority's System, all as further described in Exhibit C-Facility Description, One-Line Diagram, And Site Map, including all of the following: Seller's equipment, buildings, turbines, generators, step-up transformers, output breakers, facilities necessary to connect to the Interconnection Point, protective and associated equipment, Seller's Natural Gas Interconnection Facilities, and Seller's natural gas compression, heating and filter/separation equipment and associated piping and control systems, above ground and underground fuel piping systems and storage facilities, and other tangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for construction, operation, maintenance, generation and delivery of the capacity and energy subject to this PPA.

"Facility Debt" means the obligations of Seller or its Affiliates to any lender pursuant to the Financing Documents, or any portfolio financing, including principal of, premium and interest on indebtedness, fees, expenses or penalties, amounts due upon acceleration, prepayment or restructuring, swap or interest rate hedging breakage costs and any claims or interest due with respect to any of the foregoing.

"Facility Lender" means, collectively, any lenders providing any Facility Debt and any successors or assigns thereto.

"Facility Property" means all Seller's property rights necessary for the use of the Facility for its intended purpose, including (i) the Facility; (ii) the Site; (iii) Seller's Interconnection Facilities; (iv) the Facility collection facilities and substation; (v) Seller's rights and obligations under the Interconnection Agreement; (vi) Permits, and all material contracts; and (vii) all Facility fixtures, equipment and personal property.

“Failed Capacity Test” means a capacity test of the Facility that (i) must be cancelled because of a Forced Outage, failure of testing equipment, inclement weather, or any other reason, or (ii) if conducted, substantially fails to measure accurately the Actual Capacity of the Facility.

“Failed HR Test” means a heat rate test of the Facility that (i) must be cancelled because of a Forced Outage, failure of testing equipment, inclement weather, or any other reason, or (ii) if conducted, substantially fails to measure accurately the net heat rate of the Facility.

“Failure to Meet Accreditation Deadline” has the meaning set forth in Section 10.6(C)1.

“Federal Power Act” means the provisions of 16 U.S.C. 791(A) et seq. and amendments or supplements thereto.

“FERC” means the Federal Energy Regulatory Commission or any successor agency.

“Financing Documents” means the loan and credit agreements, notes, bonds, indentures, security agreements, lease financing agreements, mortgages, deeds of trust, interest rate exchanges, swap agreements and other documents relating to the development, bridge, construction or permanent debt financing for the Facility, including any credit enhancement, credit support, working capital financing, portfolio financing, or refinancing documents, and any and all amendments, modifications, or supplements to the foregoing that may be entered into from time to time at the discretion of Seller in connection with development, construction, ownership, leasing, operation or maintenance of the Facility.

“Fired Hour Charge” means ***[Trade Secret Data Begins...
...Trade Secret Data Ends]***.

“Force Majeure” means an event or circumstance that prevents a Party from performing its obligations under this PPA, which event or circumstance (i) was not reasonably anticipated as of the date of this PPA, (ii) is not within the control of or the result of the fault or negligence of the Party claiming its occurrence, and (iii) which by exercise of due diligence and foresight could not reasonably have been avoided. Without limiting the preceding, Force Majeure shall include acts of God; floods, earthquakes, hurricanes, and tornadoes; sabotage; vandalism beyond that which could reasonably be prevented by the Party claiming Force Majeure; terrorism; war; riots; fire; explosion; strike, slow down or labor disruption at the Site to the extent part of a general strike, slow down and/or labor disruption not otherwise confined solely to the Site; to the extent environmental hazards which could not have reasonably been detected by the environmental investigations of the Party claiming Force Majeure; severe cold or hot weather or snow or other extreme or severe weather conditions that the affected Party could not have reasonably anticipated based on the time of year and applicable geographic location; requirements, actions or failures to act by any Governmental

Authority taken after the date hereof (including the adoption or change in any rule, regulation, Permit, or environmental constraints lawfully imposed by such Governmental Authority) but only if such requirements, actions, or failures to act prevent or delay performance; mechanical or equipment breakdown, or inability to operate, attributable to circumstances occurring outside of design criteria and normal operating tolerances of similar equipment designed to be located in the local vicinity except to the extent attributable to Seller's failure to abide by Good Utility Practices; and inability, despite due diligence, to obtain any Permits required by any Governmental Authority; *provided, however, that* Force Majeure shall not include: (a) inability, or excess cost, to procure any equipment necessary to perform the obligations of this PPA; (b) acts or omissions of a third party in its capacity as a contractor or customer of the Party claiming Force Majeure unless such acts or omissions are themselves excused by reason of Force Majeure; (c) mechanical or equipment breakdown, or inability to operate, attributable to circumstances occurring within design criteria and normal operating tolerances of similar equipment designed to be located in the local vicinity; or (d) changes in market conditions.

"Forced Outage" means any condition at the Facility that requires the immediate and unplanned removal of the Facility, or some part thereof, from service, another outage state, or a reserve shutdown state, resulting from immediate mechanical/electrical/hydraulic control system trips and operator-initiated trips in response to abnormal Facility conditions or alarms.

"Fuel Delivery Point" means the natural gas delivery system point at which Company makes available and delivers to Seller the natural gas fuel consumed by the Facility to produce the Contract Energy dispatched by Company as described pursuant to Section 5.3. The Fuel Delivery Point shall be the outlet flange of the meter installed at the point of interconnection between the Natural Gas Interconnection Facilities and the Upstream Pipeline.

"Full Interconnection Agreement" means the conditions set forth in the Interconnection Agreement have been fulfilled, removed, or waived such that the Interconnection Agreement is no longer conditional and allows Seller to obtain accreditation of the Facility as a Capacity Resource for the Planning Year of COD pursuant to the Transmission Authority Capacity Accreditation Requirements.

"GDPIPD" means the Gross Domestic Product Implicit Price Deflator, as published by the US Bureau of Economic Analysis of the U.S. Department of Commerce.

"Generation Benefits" means existing or future environmental benefits or attributes, economic and other related carbon credits, carbon offsets, carbon allowances or benefits, renewable energy credits or green tags, carbon dioxide emissions credits, avoided or reduced carbon dioxide emissions, that are attributable to Energy generated by the Seller and sold to Company under this PPA, whether pursuant to or arising from any Governmental Authority or international agreement or treaty, *provided, however, that* this definition excludes any credits, offsets or other benefits

arising out of or associated with any emission or pollutant other than carbon dioxide emissions.

“Good Utility Practices” means the practices, methods, standards and acts engaged in or approved by a significant portion of the applicable segment of the electric power generation industry pertaining to facilities of the type, similar size and location to the Facility that, at a particular time, in the exercise of Commercially Reasonable judgment, in light of the facts that are known, or reasonably should have been known, at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with Applicable Law, Permits, codes, standards, equipment manufacturer’s recommendations, reliability, safety, environmental protection, economy, and expedition. Good Utility Practices is not limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods, standards and acts generally acceptable or approved by a significant portion of the applicable segment of the electric power generation industry in the relevant region, during the relevant period.

“Governmental Authority” means any federal, state, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power; or any court or governmental tribunal.

“GVTC Deferral Election” shall have the meaning set forth in Section 10.6(C)4.

“GVTC Deferral Requirements” means the applicable Transmission Tariff requirements for deferring the capacity testing that Seller must complete and report to the Transmission Authority for the Facility to be accredited by the Transmission Authority as a Capacity Resource. The current generation capacity deferral requirements are set forth in Module E-1 Resource Adequacy of the MISO OATT.

“Hazardous Materials” means any substance, material, gas, or particulate matter that is regulated listed, or identified by any local Governmental Authority, any applicable State, or the United States of America, as hazardous, dangerous, damaging, or toxic to public health, public welfare, or the natural environment including, without limitation, protection of non-human forms of life, land, water, groundwater, and air, including any material or substance that is (i) defined as “toxic,” “polluting,” “hazardous waste,” “hazardous material,” “hazardous substance,” “extremely hazardous waste,” “solid waste” or “restricted hazardous waste” under any provision of local, state, or federal law; (ii) petroleum, including any fraction, derivative or additive; (iii) asbestos; (iv) polychlorinated biphenyls; (v) radioactive material; (vi) designated as a “hazardous substance” pursuant to the Clean Water Act, 33 U.S.C. §1251 *et seq.* (33 U.S.C. §1251); (vii) defined as a “hazardous waste” pursuant to the Resource Conservation and Recovery Act, 42 U.S.C. §6901 *et seq.* (42 U.S.C. §6901); (viii) defined as a “hazardous substance” pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. §9601 *et seq.* (42 U.S.C. §9601); (ix) defined as a “chemical substance” under the Toxic Substances Control Act,

15 U.S.C. §2601 *et seq.* (15 U.S.C. §2601); or (x) defined as a pesticide under the Federal Insecticide, Fungicide, and Rodenticide Act, 7 U.S.C. §136 *et seq.* (7 U.S.C. §136).

"Heat Rate Adjustment" shall have the meaning set forth in Section 8.4.

"HHV" means Higher Heat Value.

"High Grade Collateral" or "HGC" shall have the meaning set forth in Section 11.1(D).

"House Power" means retail power to the Facility for purposes of Facility start-up or shut-down, or for any other purpose.

"Indemnified Party" shall have the meaning set forth in Section 17.1.

"Indemnifying Party" shall have the meaning set forth in Section 17.1.

"Inflation Factor" means, with respect to each Commercial Operation Year, a fraction, the numerator of which is the GDPIPD most recently announced as of the first (1st) Day of such Commercial Operation Year, and the denominator of which is the GDPIPD as of June 1, 2018.

"Interconnection Agreement" means the separate agreement among the Seller, Company, and the Transmission Authority for interconnection of the Facility to the Transmission Authority's System, as such agreement may be amended from time to time. For purposes of this PPA, the Interconnection Agreement shall be interpreted to include any third party facility construction agreement or other Agreement required by the Transmission Authority to interconnect the Facility in accordance with the Transmission Tariff.

"Interconnection Facilities" means those facilities designated in the Interconnection Agreement for the direct purpose of interconnecting the Facility at the Interconnection Point, along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities, whether owned by Seller, the Transmission Authority or another entity. This equipment is conceptually depicted in Exhibit C-Facility Description, One-Line Diagram, And Site Map to this PPA.

"Interconnection Point" means the physical point within the operational authority of the Transmission Authority as specified in the Interconnection Agreement, at which electrical interconnection is made between the Facility and the Transmission Authority's System in accordance with the Transmission Authority OATT and the Interconnection Agreement.

"Investment Grade" means a long-term credit rating (corporate or long-term senior unsecured debt) of (a) Baa3 or higher by Moody's, and (b) BBB- or higher by S&P.

"Issuer" shall have the meaning set forth in Section 11.1.

"kW" means kilowatt.

"kWh" means kilowatt hour.

"Lender Consent" shall have the meaning set forth in Section 18.1.

"Liquidated Delay Damages" means **[Trade Secret Data Begins...
...Trade Secret Data Ends]** per MW of the Nameplate Capacity of the Facility per Day.

"Local Provider" means the utility providing House Power to the Facility.

"Locational Marginal Pricing" or "LMP" shall have the meaning set forth in the Transmission Tariff.

"Maintenance Schedule" shall have the meaning set forth in Section 10.2.

"Major Equipment Failure" means either a sudden, unexpected failure or a mechanical or equipment breakdown of the steam turbine generator, condenser, circulating water pump, or cooling tower used for the operation of the Facility that: (i) substantially reduces or eliminates the capability of the Facility to produce energy, and (ii) is beyond the reasonable control of Seller and could not have been prevented by the exercise of reasonable due diligence by Seller.

"Mankato Energy Center" means, collectively, the Facility and the MEC I Facility.

"Material Adverse Effect" means any effect (or effects taken together) that is materially adverse to the present or future business, operations, assets, liabilities, properties, results in operations or condition (financial or otherwise), prospects, or property of a Party, its business, or this PPA.

"Material Permit" means any Permit designated as a "Material Permit" on Exhibit F—Material Permits.

"MEC I" shall have the meaning set forth in the first paragraph of this PPA.

"MEC I Facility" means the Mankato Facility as defined in the MEC I PPA.

"MEC I PPA" shall have the meaning set forth in Section 2.2.

"Minimum Load Starting Point" means the minimum level of operation at which the Facility is capable of receiving a dispatch signal unless there is a physical limitation to the AGC.

"Minimum Loading" means the minimum capacity the Facility can be scheduled for continuous operation according to Good Utility Practices.

“MISO” means the Midcontinent Independent Transmission System Operator, Inc., a non-profit Delaware corporation, or successor organization. MISO is the current Transmission Authority.

“Mortgaged Property” shall have the meaning set forth in Section 11.2(A).

“MPUC” means the Minnesota Public Utilities Commission.

“MW” means megawatt or one thousand kW.

“MWh” means megawatt hours.

“Nameplate Capacity” means 345 MW.

“Natural Gas Interconnection Facilities” means Seller’s, or Seller’s agent’s, pipeline, compression and related facilities required to receive, regulate and meter natural gas fuel and to transport such fuel from the Fuel Delivery Point to the Facility for the generation of electric energy under this PPA, including those facilities required to heat or filter/separate such natural gas fuel as Seller, in its sole judgment, deems necessary to install.

“Necessary Accredited Capacity Testing Results” means the capacity testing that Seller must complete and report to the Transmission Authority for the Facility to be accredited by the Transmission Authority as a Capacity Resource. The current accredited capacity testing requirements are set forth in Module E-1 Resource Adequacy of the MISO OATT.

“NERC” means the North American Electric Reliability Council or any successor organization.

“Net Capability” or “NC” means the lesser of (a) three hundred forty five (345) MW, or (b) the net generating capability of the Facility as determined by the most recent capacity test thereof, adjusted to Reference Conditions.

“Network Integration Transmission Service” or “NITS” shall have the meaning set forth in the Transmission Tariff.

“Network Resource” means the applicable amount of capacity for the Facility that has been designated as a “network resource” under the Transmission Tariff.

“Network Resource Interconnection Service” or “NRIS” shall have the meaning set forth in the Transmission Tariff.

“Network Upgrades” means the upgrades to any transmission facilities on the regional transmission system identified in the studies required pursuant to the Transmission Tariff.

“Notice(s)” shall have the meaning set forth in Section 20.1.

“Offending Party” shall have the meaning set forth in Section 20.4(B).

“Off-Peak Months” means the months of March, April, May, October and November.

“On-Peak Months” means the months of January, February, June, July, August, September and December.

“Operating Committee” means one representative each from Company and Seller pursuant to Section 10.4.

“Operating Procedures” means those procedures developed pursuant to Section 10.4, if any.

“Operating Records” means all agreements associated with the Facility, operating logs, blueprints for construction, operating manuals, all warranties on equipment, and all documents, whether in printed or electronic format, that Seller uses or maintains for the operation of the Facility.

“Operating Standards” means Company’s Operating Standards as set forth in Exhibit H-Operating Standards, as may be revised from time to time.

“Parent Guaranty” shall have the meaning set forth in Section 11.1(C)4.

“Party” and “Parties” shall have the meanings set forth in the introductory paragraph.

“Permit(s)” means all applicable construction, land use, air quality, emissions control, environmental and other permits, licenses and approvals from any Governmental Authority required under Applicable Laws for construction, ownership, operation and maintenance of the Facility and the generation and delivery of any output from the Facility to Company.

“Planning Year” means the annual capacity accreditation period that the Company is subject to as designated by the Transmission Authority. Currently under the Transmission Tariff this period is June 1st to May 31st of the following year. A Planning Year is identified by the year in which it begins. For example, the 2018 Planning Year begins June 1, 2018.

“Point of Delivery” means the physical point within the operational authority of Transmission Authority at which Seller makes available to Company and delivers to Company the Contract Capacity and Contract Energy being provided by Seller to Company from the Facility under this PPA as specified in Exhibit C-Facility Description, One-Line Diagram, And Site Map to this PPA. The Point of Delivery shall be the dead end structure on the high side of Seller’s step-up transformer at the Facility.

“PPA” shall have the meaning set forth in the introductory paragraph hereto and includes all amendments hereto.

“Post-COD Damage Cap” means *[Trade Secret Data Begins...
...Trade Secret Data Ends]*.

“Post-COD Security Fund” means *[Trade Secret Data Begins...
...Trade Secret Data Ends]*.

“Pre-COD Damage Cap” means *[Trade Secret Data Begins...
...Trade Secret Data Ends]*.

“Pre-COD Security Fund” means *[Trade Secret Data Begins...
...Trade Secret Data Ends]*.

“Predicted Net Heat Rate” means the predicted net heat rate for the Facility, stated in Btu/kWh Higher Heating Value (“HHV”), at Reference Conditions and adjusted to reflect the turbine manufacturer’s estimated degradation in equipment performance over the period of Commercial Operation from new and clean equipment conditions as specified in Exhibit J-Predicted Net Heat Rate Degradation Adjustment. The initial Predicted Net Heat Rate at new and clean equipment conditions and at Reference Conditions shall be the lesser of (i) *[Trade Secret Data Begins...
...Trade Secret Data Ends]* Btu/kWh HHV or (ii) the Actual Net Heat Rate resulting from the initial heat rate test of the Facility pursuant to Section 8.4. The Predicted Net Heat Rate degradation adjustment, as specified in Exhibit J-Predicted Net Heat Rate Degradation Adjustment, shall be used to adjust such initial Predicted Net Heat Rate, and thereby establish the Predicted Net Heat Rate, over the period.

“Reactive Power” shall have the meaning of “Reactive Supply and Voltage Control” set forth in the Transmission Tariff.

“Reference Conditions” means the Facility operating in ambient conditions used to establish the Predicted Net Heat Rate to provide a reference for adjustment in determining the Actual Net Heat Rate from heat rate testing of the Facility pursuant to Section 8.5. The ambient Reference Conditions for the Facility shall be an ambient temperature of 6.0 degrees Fahrenheit (F), 68% ambient relative humidity, and standard ambient pressure (14.696 psia at mean sea level) adjusted to the Site elevation of 800 feet above mean sea level.

“Re-mobilization Costs” has the meaning set forth in Section 2.3(B).

“Replacement Power Costs” means the costs incurred by Company that are necessary to replace the products and services that Seller was required to provide under this PPA, but failed to so provide, less the sum of any payments from Company to Seller, under this PPA, and costs of fuel that were eliminated as a result of such failure; *provided, however, that* the net amount shall never be less than zero in any hour and if the calculation for any hour results in a number less than zero, the number for such hour shall be deemed to be zero. Replacement Power Costs shall be determined on an hourly basis and shall equal the sum of all hours where the following calculation achieves a positive number.

Replacement Power Costs = (A + B + C) – D, where

“A” is the product of (x) the number of MW of capacity derived by subtracting the number of MW of capacity that qualifies for capacity credit actually made available to Company from the Contract Capacity, and (y) the applicable market price for capacity made available to Company’s system plus any other associated costs and penalties arising out of Seller’s failure to perform;

“B” is the product of the number of MWh of energy purchased by Company associated with the replacement capacity and the applicable market price for energy delivered to Company’s system at a point nearest to the Point of Delivery for the hour plus any other associated costs and penalties arising out of Seller’s failure to perform; and

“C” an amount equal to the actual cost of transmission, ancillary services, fuel and fuel transportation and related penalties that could not be avoided or mitigated and transaction charges to deliver reasonably available energy to Company in amounts equal to the number of MWh for which Replacement Power Costs are owed;

“D” is the sum of any payments from Company to Seller, under this PPA that would have been made but were eliminated as a result of such failure and any costs of fuel that can be reasonably avoided by Company to obtain replacement energy.

“Reported Availability” shall have the meaning set forth in Section 10.1(B)(2).

“ROFO Notice” shall have the meaning set forth in Section 19.2(A).

“SCADA” means supervisory control and data acquisition.

“Scheduled Termination Date” means through and including the last Day of a Planning Year on or immediately after the twentieth (20th) anniversary of the COD.

“Scheduled Maintenance Energy” shall have the meaning set forth in Section 8.1.

“Scheduled Outage/Derating” means a planned interruption/reduction of the Facility’s generation that both (i) has been coordinated in advance with Company, with a mutually agreed start date and duration, (ii) is required for inspection, or preventive or corrective maintenance, and (iii) complies with the Transmission Authority scheduling requirements as set forth in the Transmission Authority Business Practices Manual for Outage Operations.

“Scheduling Charge” means the product of [**Trade Secret Data Begins...
...Trade Secret Data Ends**] multiplied by the Inflation Factor.

“Security Fund” means the letter of credit, escrow fund, guaranty and/or other collateral that Seller is required to establish and maintain, pursuant to Section 11.1, as security for Seller’s performance under this PPA.

“Seller’s Reimbursable Transmission Costs” means all the engineering, design, procurement, and construction costs Seller incurs for transmission facilities required under the Interconnection Agreement, and the costs Seller shall incur for Network Upgrades associated with Company obtaining firm NITS for the Facility.

“Shut-Down Period” means any period during which the Facility has completed its run schedule, is taken off AGC, and ramps down to breaker open.

“Site” means the parcel of real property on which the Facility will be constructed and located, including any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of the Facility. The Site is more specifically described in Exhibit C-Facility Description, One-Line Diagram, And Site Map to this PPA.

“Site Permit” means any Permit, or any amendment to an existing Permit, required by Applicable Law to authorize the construction and siting of the Facility at the Site.

“Start-Up Period” means any period during which the Facility is ramping from breaker close to its Minimum Load Starting Point.

“Start-up Testing” means the initial synchronization to the Transmission System, including production of energy as measured on the Electric Metering Devices.

“State Regulatory Agency” means the North Dakota Public Service Commission, and any successor agency thereof.

“State Regulatory Approval” means a final, non-appealable written order of the North Dakota Public Service Commission making the affirmative determination that Company’s execution of this PPA is reasonable, in the public interest, and all costs incurred under this PPA are recoverable from the retail customers pursuant to Applicable Law, subject only to the requirement that the State Regulatory Agency retains ongoing prudence review of Company’s performance and administration of this PPA.

“Step-in Rights” means Company’s right, but not the obligation, to assume control and operate the Facility as agent for Seller (whether voluntary or involuntary) in accordance with Seller’s right, obligations, and interest under this PPA.

“Subordinated Mortgage” shall have the meaning set forth in Section 11.2(A).

“Successful Start” means, in response to a request from Company to start the Facility, Seller’s start and operation of the Facility that: (i) achieves the Minimum Loading level for the requested operating configuration within the greater of (a) two hundred thirty (230) minutes after the time Company requested the turbine start to begin or (b) the operating parameters of the air Permit, and (ii) upon achieving the aforementioned Minimum Loading level, generates continuously for a period of not less

than one hour while synchronized to the Transmission Authority's System at or above such Minimum Loading level without experiencing any abnormal operating conditions.

"Term" means the period of time during which this PPA shall remain in full force and effect as further defined in Article 2.

"Test Energy" means that energy which is produced by the Facility, delivered to Company at the Point of Delivery, and purchased by Company pursuant to Section 4.4 in order to perform testing of the Facility.

"Test Energy Rate" means *[Trade Secret Data Begins...
...Trade Secret
Data Ends]*.

"Tolling Price" means *[Trade Secret Data Begins...
...Trade Secret
Data Ends]*.

"Transmission Authority" means collectively those entities owning and/or operating the interconnected transmission system applicable to Seller and the Facility pursuant to the Transmission Tariff, including (i) Midcontinent Independent Transmission System Operator, Inc. ("MISO"), a non-profit, Delaware corporation, or successor organization and (ii) all entity(s) responsible under the Interconnection Agreement for providing the transmission lines, any Interconnection Facilities and other equipment and facilities with which the Facility interconnects at the Interconnection Point and transmission system.

"Transmission Authority Capacity Accreditation Requirements" means the applicable Transmission Tariff requirements for accreditation of the capacity of new generation added to the Transmission Authority's System. The current capacity accreditation requirements are set forth in Module E-1 Resource Adequacy of the MISO OATT.

"Transmission Authority's System" means the contiguously interconnected electric transmission and sub-transmission facilities over which the Transmission Authority has rights (by ownership or contract) to provide bulk transmission of capacity and energy from the Interconnection Point.

"Transmission Tariff" means the applicable open access transmission tariff of the Transmission Authority, as amended from time to time. The current Transmission Tariff is the MISO OATT.

"Turbine Start Payment" shall have the meaning set forth in Section 8.6.

"Turbine Start Price" means *[Trade Secret Data Begins...
...Trade
Secret Data Ends]* per Successful Start.

"UCP" shall have the meaning set forth in Exhibit G-1, Form of Letter of Credit.

“Unrecovered Costs for Early Termination” has the meaning set forth in Section 2.4(A).

“Upstream Pipeline” means Northern Natural Gas, the interstate natural gas pipeline interconnecting to the Facility at the Fuel Delivery Point and providing Acceptable Natural Gas Fuel to the Facility in accordance with its applicable tariff.

“Wenck Environmental Assessments” means the following Environmental Assessments performed by Wenck Associates, Inc.: Phase I Environmental Site Assessment—Mankato Energy Center Site, Mankato, Minnesota (September 2003); Limited Phase II Environmental Site Assessment—Mankato Energy Center Site, Mankato, Minnesota (December 2003); Phase I Environmental Site Assessment—Residential Property, 3274 Third Avenue, Mankato Minnesota (July 2004); Phase I Environmental Site Assessment—Remote Equipment Area, County Road 5 and Industrial Drive, Line Township, Minnesota (April 2005); Phase I Environmental Site Assessment—Pipeline Corridor, Mankato, Minnesota (July 2005); Phase I Environmental Site Assessment—Mankato Energy Center, LLC. 1 Fazio Lane, Mankato, Minnesota (August/September 2009); Phase I Environmental Site Assessment—Mankato Energy Center, LLC. Natural Gas Pipeline Corridor, Mankato, Minnesota (August, 2009); Phase I Environmental Site Assessment—Mankato Energy Center, LLC. Water Pipeline Within Section 31, T109N, R26W and Section 7, T108N, R26W, Mankato, Minnesota (August 2009).

EXHIBIT B

CONSTRUCTION MILESTONES

All Construction Milestones are subject to extension in accordance with the terms of the PPA.

Construction Milestone	Outcome
<i>[Trade Secret Data Begins...</i>	
	Company shall have obtained State Regulatory Approval.
	Seller and all required counterparties have executed major procurement contracts, the Construction Contract (Limited Notice To Proceed Only), any operating agreements, and the Interconnection Agreement needed to commence construction of the Facility.
	Seller shall have achieved closing on financing for the Facility or provided Company with proof of financial capability to construct the Facility.
	Seller shall have laid the foundation for generating facilities and step-up transformation facilities.
	The turbine(s)/generator(s)/step-up transformer shall have been delivered to, and set on foundation at, the Site.
	All Network Upgrades associated with obtaining NITS are completed.
	All fuel supply and transportation arrangements have been put in place and fuel interconnection facilities in have been constructed and are operational.
	Seller shall have constructed Seller's Interconnection Facilities and such facilities are capable of being energized
	Commissioning of the Facility commences.
	Seller shall have obtained either (i) unconditional ERIS and

	unconditional NITS, or (ii) unconditional NRIS.
	Seller shall have obtained MISO accreditation of the Facility as a Capacity Resource
	Commercial Operation Milestone
...Trade Secret Data Ends]	
June 1, 2018	Commercial Operation Date

EXHIBIT C

FACILITY DESCRIPTION, ONE-LINE DIAGRAM, AND SITE MAP

Site Location

The Facility will be located on a 25-acre site within the Mankato city limits in Blue Earth County, Minnesota, northwest of the County Highway 5 and Summit Avenue intersection. A one-line diagram of the Facility and site map is included in this Exhibit.

General

The Facility will consist of a combustion turbine generator (CTG) and heat recovery steam generator (HRSG) and associated balance of plant items required to supplement the MEC I Facility's 1x1x1 configuration to achieve a 2x2x1 configured plant. The Facility's CTG and HRSG will combust natural gas only.

Major New Equipment

The Facility's equipment will include: one (1) 501FD CTG, one (1) new generator step up transformer, one (1) natural gas, supplementary fired HRSG, plus associated switchgear, motor control centers, water treatment, and an expansion to the existing evaporative cooling tower.

Support Buildings

The existing administration/maintenance/warehouse/control building will be used for any Facility activities. Additionally, the existing water treatment building will be used to house any additional demineralization equipment and water lab equipment need to support the expanded operations.

Water

The Facility will make use of existing infrastructure to receive and discharge water. Gray water will be provided by the City of Mankato Municipal Wastewater Treatment Plant. Additional wastewater treatment facilities are located at the municipal treatment plant which is approximately one mile due south from the Facility. Two existing pipelines will transport gray water to the Facility and return discharged water from the Facility. The wastewater facilities are owned by the City of Mankato. Potable water is provided by the City of Mankato's water distribution system.

Gas Interconnection

A 20-inch natural gas lateral was constructed to provide fuel to the MEC I Facility and the Facility. The lateral connects to the Northern Natural Gas system which is located approximately 3.5 miles to the East of the Facility. The lateral is capable of serving the fuel requirements for the Facility and the MEC I Facility.

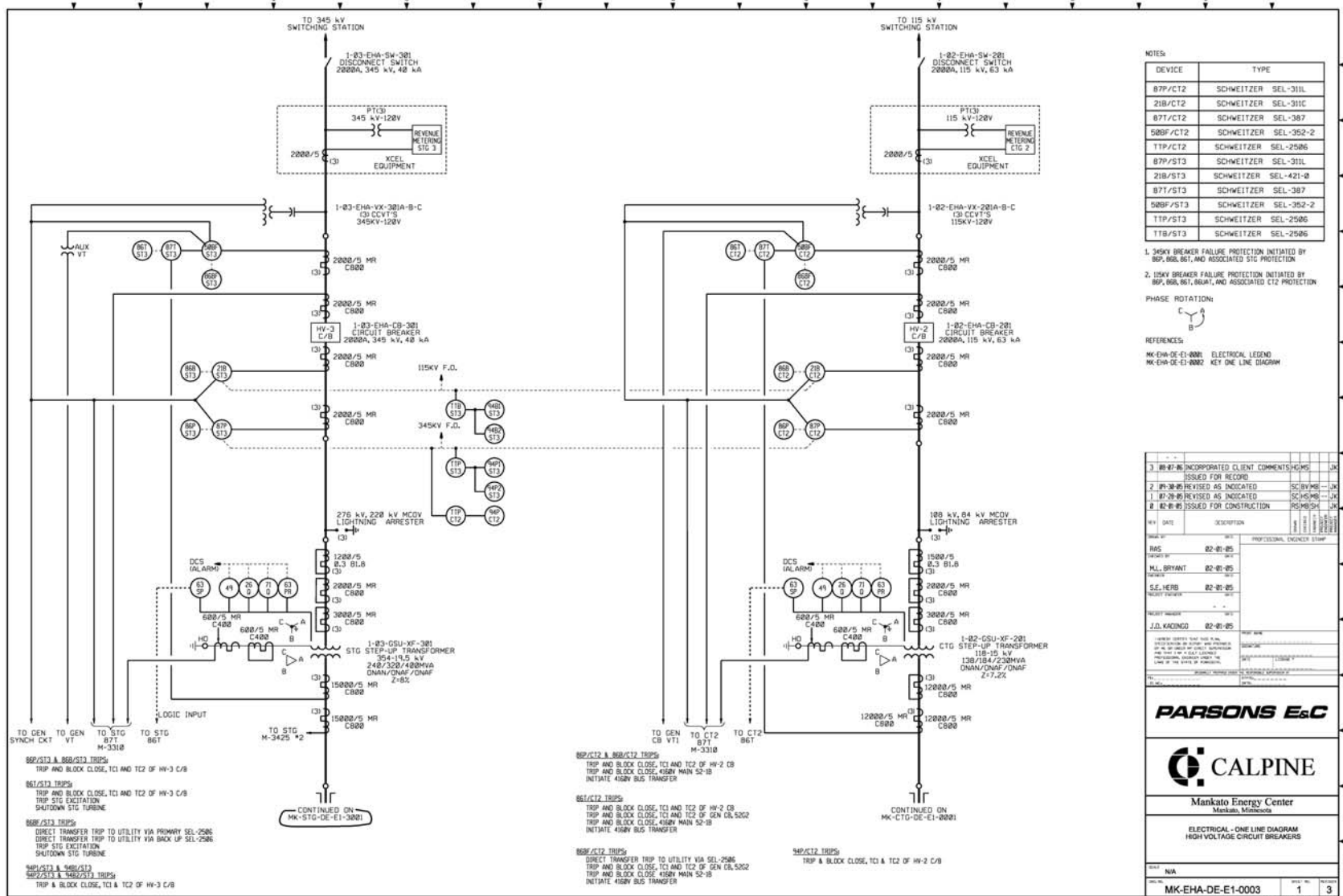
Electrical Interconnection

As described in the Interconnection Agreement, as may be amended from time to time, which as of August 29, 2014 provides as follows:

The Facility will be interconnected to Company's Wilmarth Substation, located approximately 2,500 feet west of the Facility, via a new 115 kV circuit.

Point of Interconnection. The Facility's point of interconnection is identified in the Interconnection Agreement. Currently, the point of interconnection is identified as the point where the transmission owner's new 115 kV line from the Mankato substation connects with the dead-end A-frame structure at the high side of the Facility's step-up transformer.

Interconnection Facilities (including metering equipment) to be constructed by Facility. The Facility's interconnection facilities are identified in the Interconnection Agreement, and currently are identified as requiring the following: one 115 kV breaker, and new line relaying and associated protection and metering equipment on Facility's side of the new 115 kV point of interconnection.



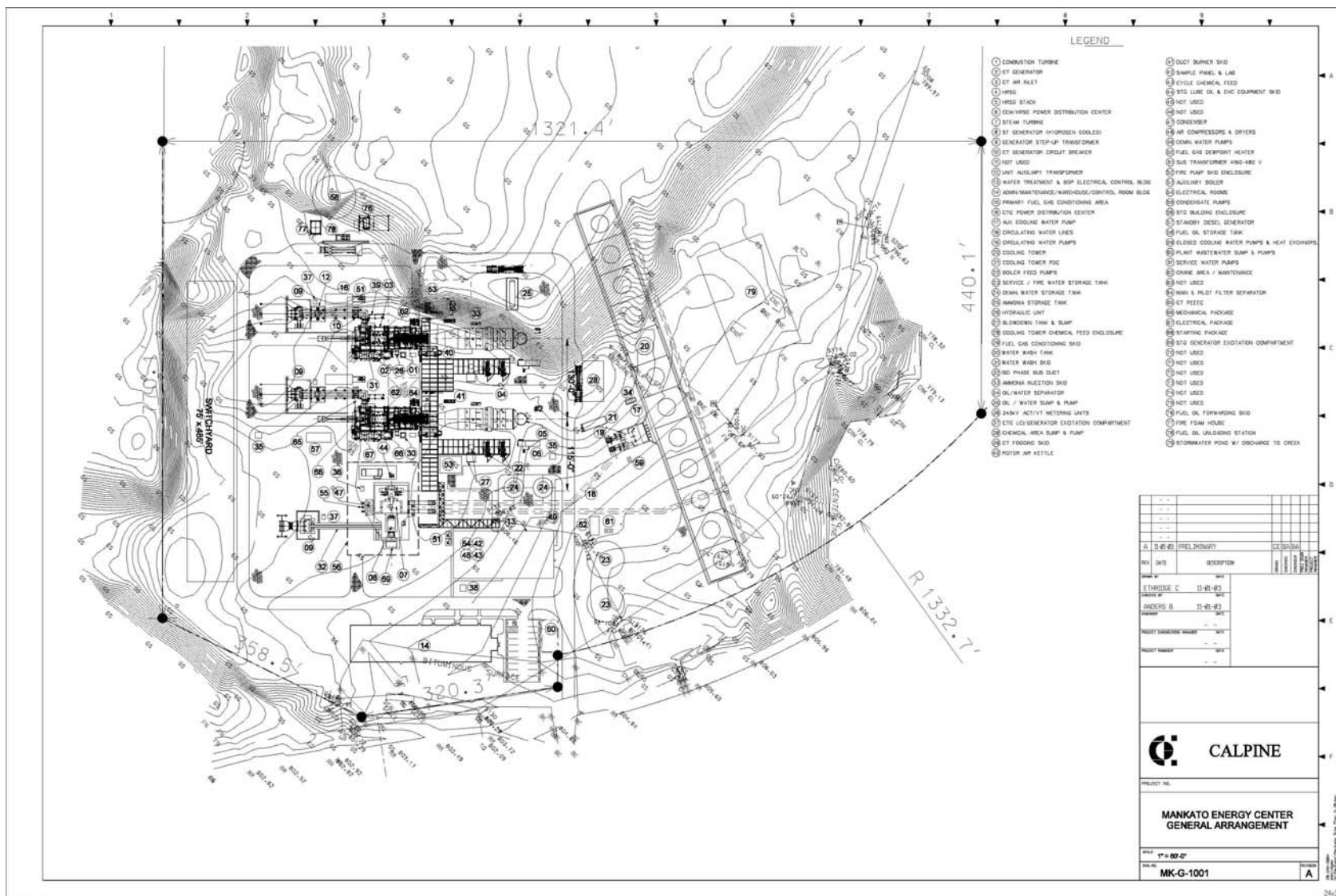


EXHIBIT D

NOTICES AND CONTACT INFORMATION

Company	Seller
<p>Notices:</p> <p>Tim Kawakami Director, Purchased Power Xcel Energy Services Inc. 1800 Larimer Street, Suite 1000 Denver, CO 80202 Phone: 303-571-2748 Email: tim.kawakami@xcelenergy.com Fax: 303-571-2913</p> <p>Jeff Klein Manager, Structured Purchases Xcel Energy Services Inc. 1800 Larimer Street, Suite 1000 Denver, CO 80202 Phone: 303-571-2732 Email: jeffrey.klein@xcelenergy.com Fax: 303-571-2913</p> <p>Jeanette Schuck Purchased Power Analyst Xcel Energy Services Inc. 1800 Larimer Street, Suite 1000 Denver, CO 80202 Phone: 303-571-7428 Email: jeanette.r.schuck@xcelenergy.com Fax: 303-571-2913</p>	<p>Notices:</p> <p>Mankato Energy Center II, LLC Attention: Vice President East Power Trading 717 Texas Avenue, Suite I 000 Houston, TX 77002 Email: CommodityContracts@calpine.com Facsimile: 713-830-8751</p> <p>Mankato Energy Center II, LLC Attention: Risk Management Counsel 717 Texas Avenue, Suite I 000 Houston, TX 77002 Email: CommodityContracts@calpine.com Facsimile: 713-325-1508</p>
<p>Operating Committee Representative:</p> <p>Jeff Klein Manager, Structured Purchases Xcel Energy Services Inc. 1800 Larimer Street, Suite 1000 Denver, CO 80202 Phone: 303-571-2732 Email: jeffrey.klein@xcelenergy.com</p>	<p>Operating Committee Representative:</p> <p>Asset Manager c/o Calpine Corporation East Region Office 500 Delaware Avenue, Suite 600 Wilmington, DE 19801 Phone: 302-468-5340</p>

<p>Fax: 303-571-2913</p> <p>Alternate: Jeanette Schuck Purchased Power Analyst Xcel Energy Services Inc. 1800 Larimer Street, Suite 1000 Denver, CO 80202 Phone: 303-571-7428 Email: jeanette.r.schuck@ xcelenergy.com Fax: 303-571-2913</p>	
<p>Real-Time Contact Information</p> <p>Real-time Communications Contact Real-time Generation Dispatch desk (24 hour coverage) Mark Schultz, or Shift Operator Phone: 303-571-7426 Fax: 303-571-7305 E-mail: mark.schultz@xcelenergy.com</p> <p>Transmission Operation Contact Position: Real Time Transmission Operations Todd Sarkinen, or Shift Operator Phone: 612-321-7432 FAX: 303-571-7305 E-mail: todd.k.sarkinen@ xcelenergy.com</p>	<p>Real-Time Contact Information</p> <p>Calpine 24-hour Desk Calpine Corporation 717 Texas Avenue, Suite 1000 Houston, TX 77002 Phone: 713-830-2083</p>

EXHIBIT E

INSURANCE COVERAGE

Type of Insurance	Minimum Limits of Coverage
Commercial General Liability (CGL) and commercial umbrella	\$11,000,000 combined single limit each occurrence and the aggregate, where applicable.

CGL insurance shall be written on ISO occurrence form CG 00 01 01 96 (or a substitute form providing equivalent coverage) and shall cover liability arising from premises, operations, independent contractors, products/completed operations, contracts, property damage, personal injury and advertising injury, and liability assumed under an insured contract (including the tort liability of another assumed in a business contract), all with limits as specified above. CGL insurance shall include ISO endorsement CG 24 17 (or an equivalent endorsement) which modifies the definition of "Insured contract" to eliminate the exclusion of easement or license agreements in connection with construction or demolition operations on or within 50 feet of a railroad. There shall be no endorsement or modification of the CGL insurance limiting the scope of coverage for liability arising from explosion, collapse, or underground property damage.

Company shall be included as an insured under the CGL policy, using ISO additional insured endorsement CG 20 10 (or a substitute providing equivalent coverage), and under the commercial umbrella insurance. The commercial umbrella insurance shall provide coverage over the top of the CGL insurance, the Business Automobile Liability insurance, and the Employers Liability insurance.

The CGL and commercial umbrella insurance to be obtained by or on behalf of Seller shall be endorsed substantially (by blanket endorsement or otherwise) as follows:

Such insurance as afforded by this policy for the benefit of Company shall be primary as respects any claims, losses, damages, expenses, or liabilities arising out of this PPA, and insured hereunder, and any insurance carried by Company shall be excess of and noncontributing with insurance afforded by this policy.

Business Automobile Liability	\$1,000,000 combined single limit (each accident), including all Owned, Non-Owned, Hired and Leased Autos.
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Business Automobile Liability insurance shall be written on ISO form CA 00 01, CA 00 05, CA 00 12, CA 00 20, or a substitute form providing equivalent liability coverage. If necessary, the policy shall be endorsed to provide contractual liability coverage equivalent to that provided in the 1990 and later editions of CA 00 01.

Workers Compensation	Statutory Requirements. Seller may comply with these requirements through the use of a qualified self-insurance plan.
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Type of Insurance	Minimum Limits of Coverage
Employers Liability	\$1,000,000 each accident for bodily injury by accident, or \$1,000,000 each employee for bodily injury by disease.

Builder's Risk	Replacement value of the Facility.
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Builder's Risk insurance, or an installation floater, shall include coverage for earthquake and flood, collapse, faulty workmanship, materials and design, testing of machinery or equipment, freezing or changes in temperature, debris removal, and partial occupancy, with sublimits as appropriate.

All-Risk Property insurance covering physical loss or damage to the Facility	Full replacement value of the Facility. A deductible may be carried which deductible shall be the absolute responsibility of Seller.
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All-Risk Property insurance shall include: (i) coverage for fire, flood, wind and storm, tornado and earthquake with respect to facilities similar in construction, location and occupancy to the Facility, with sublimits of no less than \$10,000,000 each for flood and earthquake; and (ii) Boiler and Machinery insurance covering all objects customarily subject to such insurance, including boilers and turbines, in an amount equal to their full replacement value.

Business Interruption insurance	Amount required to cover Seller's continuing or increased expenses, resulting from full interruption, for a period of 12 calendar months.
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Business Interruption insurance shall cover loss of revenues or the increased expense to resume operations attributable to the Facility by reason of total or partial suspension or delay of, or interruption in, the operation of the Facility as a result of an insured peril covered under Property insurance as set forth above, to the extent available on Commercially Reasonable terms as determined by Company, subject to a deductible that shall be the responsibility of Seller. Notwithstanding any other provision of this PPA, Seller shall not be required to have Business Interruption insurance until the Commercial Operation Date.

EXHIBIT F

MATERIAL PERMITS

1. Air Permit
2. Site Permit
3. [Reserved]

EXHIBIT G
FORM OF SECURITY DOCUMENTS

EXHIBIT G-1

FORM OF LETTER OF CREDIT

LETTERHEAD OF ISSUING BANK

Irrevocable Standby Letter of Credit
No: _____

Beneficiary:

Date of Issuance: _____
Initial Expiration Date: [Must be at least one year after date of issuance]

Applicant:

As the Issuing Bank ("Issuer"), we, [Name of Issuing Bank], hereby establish this irrevocable Standby Letter of Credit No. _____ (this "Letter of Credit") in favor of the above-named beneficiary ("Beneficiary") for the account of the above-named applicant ("Applicant") in the amount of USD \$ _____ (_____ U.S. Dollars).

Beneficiary may draw all or any portion of this Letter of Credit at any time and from time to time, and Issuer will make funds available to Beneficiary, upon presentation of the following documents (collectively, the "Presentation Documents"):

1. Beneficiary's draft(s) at sight in substantially the form attached hereto as Exhibit "A" ("Sight Draft"), drawn on Issuer and signed on behalf of Beneficiary, with Beneficiary's signatory indicating his or her title or other official capacity;
2. This Letter of Credit; and
3. A statement signed by an authorized officer or representative of Beneficiary substantially as follows:

"The undersigned hereby certifies that (i) I am duly authorized to execute this document on behalf of Northern States Power Company, (ii) the amount of the draft accompanying this certification is an undisputed amount due and owing to Northern States Power Company by virtue of a breach by Mankato Energy Center II, LLC under the terms of the Power Purchase Agreement dated as of _____, and (iii) all applicable notice-and-cure periods have expired."

or as follows:

"The undersigned hereby certifies that (i) I am duly authorized to execute this document on behalf of Northern States Power Company, and (ii) Northern States Power Company has

received notice that this Letter of Credit will not be extended beyond its Expiry Date, and Mankato Energy Center II, LLC has failed to provide alternate security to Northern States Power Company as required under the Power Purchase Agreement dated as of _____ within ten (10) days prior to the Expiry Date of the Letter of Credit.”

No documents other than the Presentation Documents will be required to be presented. Issuer will effect payment under this Letter of Credit within three (3) banking days following the date of Issuer’s receipt of the required Presentation Documents. Payment shall be made in U.S. Dollars with Issuer’s own funds in immediately available funds.

Issuer will honor any Sight Draft presented in compliance with the terms of this Letter of Credit at the Issuer’s letterhead office, the office located at _____ or any other full service office of the Issuer on or before the above-stated expiration date, as such expiration date may be extended hereunder. Partial and multiple draws and presentations are permitted on any number of occasions. Following any partial draw, Issuer will endorse this Letter of Credit and return the original to Beneficiary.

Issuer acknowledges that this Letter of Credit is issued pursuant to the provisions of that certain Power Purchase Agreement between Beneficiary and Applicant dated as of _____, 20__ (as the same may have been or may be amended from time to time, the “PPA”). Notwithstanding any reference in this Letter of Credit to the PPA or any other documents, instruments or agreements, or references in the PPA or any other documents, instruments or agreements to this Letter of Credit, this Letter of Credit contains the entire agreement between Beneficiary and Issuer relating to the obligations of Issuer hereunder.

This Letter of Credit will be automatically extended each year without amendment for a period of one (1) year from the expiration date hereof, as extended, unless at least thirty (30) days prior to the expiration date, Issuer notifies Beneficiary by registered mail that it elects not to extend this Letter of Credit for such additional period. Notice of non-extension will be given by Issuer to Beneficiary at Beneficiary’s address set forth herein or at such other address as Beneficiary may designate to Issuer in writing at Issuer’s letterhead address. The date on which this Letter of Credit expires (as such date may be extended pursuant to this paragraph) is referred to herein as the “Expiry Date.”

This Letter of Credit is not transferable or assignable by Beneficiary, except that this Letter of Credit may be transferred in its entirety to, and only to, any transferee who has succeeded to Beneficiary’s rights under the PPA, and notwithstanding any contrary provision in the UCP, such transferred Letter of Credit may be successively so transferred. Issuer agrees that it will affect any transfers immediately upon presentation to Issuer of this Letter of Credit and a completed written transfer request in a form acceptable to Issuer in Issuer’s sole

discretion. Any transfer fees assessed by Issuer will be payable solely by Beneficiary.

Issuer waives any rights it may have, at law or otherwise, to subrogate to any claims Beneficiary may have against Applicant or Applicant may have against Beneficiary.

This Letter of Credit is subject to the uniform customs and practice for documentary credits (2007 Revision), International Chamber of Commerce publication No. 600 (The "UCP"), except to the extent that the terms hereof are inconsistent with the provisions of the UCP, including but not limited to Articles 14(b) and 36 of the UCP, in which case the terms of this Letter of Credit shall govern. With respect to Article 14(b) of the UCP, Issuer shall have a reasonable amount of time, not to exceed three (3) banking days following the date of Issuer's receipt of documents from Beneficiary (to the extent required herein), to examine the documents and determine whether to take up or refuse the documents and to inform Beneficiary accordingly.

In the event of an act of God, riot, civil commotion, insurrection, war or any other cause beyond Issuer's control that interrupts Issuer's business and causes the place for presentation of this Letter of Credit to be closed for business on the last day for presentation, the expiry date of this Letter of Credit will be automatically extended without amendment to a date thirty (30) calendar days after the place for presentation reopens for business.

ISSUER:

By: _____
Authorized Signature

Name: _____
Its: _____

EXHIBIT "A"
TO LETTER OF CREDIT

SIGHT DRAFT

Draft Number _____
\$ _____

At sight, pay to the order of [Name of Beneficiary to be inserted], the amount of USD \$ _____ (_____ and 00/100ths U.S. Dollars).

Value received and charged to the account of: [Name of Issuer and address].
Drawn under [Name of Issuer to be inserted] Standby Letter of Credit No. _____.

Dated: _____, 20__

[Name of Beneficiary to be inserted]

By: _____

Name: _____
Its Authorized Representative and [Title
or Other official Capacity to be
inserted]

Account: [Applicant to be inserted]

EXHIBIT G-2

FORM OF GUARANTY

This Guaranty is executed and delivered as of this _____ day of _____, 20__ by _____, a _____ (“Guarantor”), in favor of _____ (“Company”), in connection with the performance by _____, a _____ [limited liability company] (“Seller”) of a Power Purchase Agreement dated _____, 20__ between Seller and Company (the “PPA”).

- RECITALS -

A. Seller is planning to construct, own, and operate an electric generation facility having Nameplate Capacity of approximately _____ MW to be located in _____ County, _____ (the “Facility”).

B. Seller and Company have entered into the PPA for the purchase and sale of capacity and electrical energy from the Facility on the terms and conditions set forth therein.

Seller is controlled by Guarantor. Guarantor expects to derive substantial benefits from the performance of the PPA by Seller and Company. To induce Company to enter into the PPA and consummate the purchase and sale of electrical energy contemplated by the PPA, Guarantor has agreed to guarantee the obligations of Seller as provided in this Guaranty.

NOW, THEREFORE, in consideration of the foregoing, Guarantor agrees as follows:

- AGREEMENT -

1. Guaranty. Subject to the provisions of this Guaranty, including any applicable exceptions or limitations, Guarantor hereby absolutely, irrevocably, unconditionally, and fully guarantees to Company the due, prompt, and complete observance, performance, and discharge of each and every payment obligation of Seller under the PPA, whether incurred before or after the date of delivery of this Guaranty (the “Obligations”). This is a guaranty of payment, not of collection, and as such, Company shall not be required to institute, pursue, or exhaust any remedies against Seller before instituting suit, obtaining judgment, and executing thereon against Guarantor under this Guaranty.

2. Maximum Liability. Notwithstanding anything herein to the contrary, Guarantor’s maximum liability under this Guaranty shall be limited to (\$US_____).

3. Rights of Company. Guarantor hereby grants to Company, in Company’s discretion and without the need to notify or obtain any consent from Guarantor, and

without termination, impairment, or any other effect upon Guarantor's duties hereunder, the power and authority from time to time:

(a) to renew, compromise, extend, accelerate, or otherwise change, substitute, supersede, or terminate the terms of performance of any of the Obligations, in each case in accordance with the PPA, except that any such renewal, compromise, extension, acceleration or other change shall not enlarge Guarantor's obligations under this Guaranty and Guarantor shall have the benefit of any such renewal, compromise, extension, acceleration or other change as Seller (e.g., if Seller's time for payment of an Obligation has been extended, Guarantor shall have no obligation under this Guaranty to make payment of such Obligation until such time as Seller is required under the extension to make payment);

(b) to grant any indulgences, forbearances, and waivers, on one or more occasions, for any length of time, with respect to Seller's performance of any of the Obligations; and

(c) to accept collateral, further guaranties, and/or other security for the Obligations, and, if so accepted, then to impair, exhaust, exchange, enforce, waive, or release any such security.

4. Performance. If any of the Obligations are not performed according to the tenor thereof, and any applicable notice and cure period provided by the PPA has expired ("Default"), Guarantor shall immediately upon receipt of written demand by Company (a) perform or cause Seller to perform the Obligation in Default, and (b) pay, reimburse, and indemnify Company against any liabilities, damages, and related costs (including attorneys' fees) incurred by Company as a result of any efforts to collect or enforce any valid obligations under this Guaranty all in such manner and at such times as Company may reasonably direct. All payments hereunder shall be made without reduction, whether by offset, payment in escrow, or otherwise, except to the extent of any defenses to payment or performance which Seller may have under the PPA (other than defenses arising out of the bankruptcy, insolvency, dissolution or liquidation of Seller, the power or authority of Seller to enter into the PPA, and to perform the Obligations, and the lack of validity or enforceability of the PPA or any other documents executed in connection with the PPA).

5. Satisfaction. Satisfaction by Guarantor of any duty hereunder incident to a particular Default or the occurrence of any other Default shall not discharge Guarantor except with respect to the Default satisfied, it being the intent of Guarantor that this Guaranty, subject to any applicable limitations or exceptions hereunder, be continuing until such time as all of the Obligations have irrevocably been discharged in full, at which time this Guaranty shall automatically terminate. If at any time the performance of any Obligation by Seller or Guarantor is rescinded or voided under the federal Bankruptcy Code or otherwise, then Guarantor's duties hereunder shall continue and be deemed to have been automatically reinstated, restored, and continued with respect to that Obligation, as though the performance of that Obligation had never occurred,

regardless of whether this Guaranty otherwise had terminated or would have been terminated following or as a result of that performance.

6. Notice of Acceptance. Guarantor waives and acknowledges notice of acceptance of this Guaranty by Company.

7. Waivers by Guarantor. Guarantor hereby waives and agrees not to assert or take advantage of:

(a) all set-offs, counterclaims, and, subject to Section 4 above, all presentments, demands for performance, notices of non-performance, protests, and notices of every kind that may be required by Applicable Laws;

(b) any right to require Company to proceed against Seller or any other person, or to require Company first to exhaust any remedies against Seller or any other person, before proceeding against Guarantor hereunder;

(c) any defense based upon an election of remedies by Company, subject to Company's obligation to reasonably mitigate damages;

(d) any duty of Company to protect or not impair any security for the Obligations;

(e) the benefit of any laws limiting the liability of a surety;

(f) any duty of Company to disclose to Guarantor any facts concerning Seller, the PPA or the Project, or any other circumstances, that would or allegedly would increase the risk to Guarantor under this Guaranty, whether now known or hereafter learned by Company, it being understood that Guarantor is capable of and assumes the responsibility for being and remaining informed as to all such facts and circumstances; and

(g) until all Obligations in Default have been fully paid and/or performed, any rights of subrogation, contribution, reimbursement, indemnification, or other rights of payment or recovery for any payment or performance by it hereunder. For the avoidance of doubt, if any amount is paid to Guarantor in violation of this provision, such amount shall be held by Guarantor for the benefit of, and promptly paid to, Company.

8. Termination and Release. This Guaranty shall terminate on the date (the "Termination Date") that is the earlier of (i) thirty (30) days after prior written notice of termination of this Guaranty has been received by Company, or (ii) the date when all Obligations have been paid; *provided, however, that* this Guaranty shall continue to remain in force following the Termination Date with respect to any Obligations of Seller arising on or prior to the Termination Date.

9. Release and Assignment. Upon (i) the transfer or assignment by Seller of the PPA or any rights thereunder to any third party that is not an Affiliate (as defined in the PPA) of Guarantor whereby Seller is released from or relieved of its obligations

under the PPA pursuant to the terms of the PPA or (ii) a Change of Control (as defined in the PPA) of Seller that results in Seller no longer being a direct or indirect subsidiary of Guarantor, Guarantor's obligations under this Guaranty shall be released and discharged, except with respect to Guarantor's guarantee of any Obligations of Seller arising on or prior to the effective date of such assignment or Change of Control. Company hereby agrees to enter into a mutually acceptable agreement to evidence, or otherwise provide adequate assurance of, any such release or discharge. Subject to the foregoing in this Section 9, Guarantor may not assign this Guaranty or its obligations hereunder without the prior written consent of Company, which consent of Company shall not be unreasonably withheld or delayed.

10. Cumulative Remedies. The rights and remedies of Company hereunder shall be cumulative and not alternative to any other rights, powers, and remedies that Company may have at law, in equity, or under the PPA. The obligations of Guarantor hereunder are independent of those of Seller and shall survive unaffected by the bankruptcy of Seller. Company need not join Seller in any action against Guarantor to preserve its rights set forth herein.

11. Representations and Warranties. Guarantor represents and warrants to Company as follows:

(a) Guarantor is a corporation, duly organized, validly existing, and in good standing under the laws of the state of its incorporation. Seller is a direct or indirect subsidiary of Guarantor. Guarantor has all necessary corporate power and authority to execute and deliver this Guaranty and to perform its obligations hereunder.

(b) The execution, delivery and performance of this Guaranty has been duly and validly authorized by all corporate proceedings of Guarantor and is not in violation of any law, judgment of court or government agency. This Guaranty has been duly and validly executed and delivered by Guarantor and constitutes a legal, valid and binding obligation of Guarantor, enforceable against Guarantor in accordance with its terms.

12. Collection Costs. Guarantor hereby agrees to pay to Company, upon demand, all reasonable attorneys' fees and other expenses which Company may expend or incur in enforcing this Guaranty against Guarantor, whether or not suit is filed.

13. Severability. Should any one or more provisions of this Guaranty be determined to be illegal or unenforceable, all other provisions nevertheless shall be effective.

14. Waiver or Amendment. No provision of this Guaranty or right of Company hereunder can be waived, nor can Guarantor be released from Guarantor's duties hereunder, except by a writing duly executed by Company. This Guaranty may not be modified, amended, revised, revoked, terminated, changed, or varied in any way whatsoever except by the express terms of a writing duly executed by Company or as expressly provided herein.

15. Successors and Assigns. This Guaranty shall inure to the benefit of and bind the successors and assigns of Company and Guarantor.

16. Governing Law and Limitation of Liability. **THIS GUARANTEE SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK WITHOUT REFERENCE TO CHOICE OF LAW DOCTRINE. CALPINE HEREBY IRREVOCABLY WAIVES ANY AND ALL RIGHT TO A TRIAL BY JURY WITH RESPECT TO ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS GUARANTEE. IN NO EVENT SHALL CALPINE BE LIABLE UNDER THIS GUARANTEE FOR ANY CONSEQUENTIAL, SPECIAL, EXEMPLARY OR PUNITIVE DAMAGES AND NO SUCH DAMAGES MAY BE AWARDED IN ANY PROCEEDING.**

17. Miscellaneous. This Guaranty shall not be deemed to benefit any person except Seller, Guarantor and Company. This Guaranty supercedes and replaces any guarantees made by Guarantor that pertain to the PPA prior to the effective date of this Guaranty.

18. Notices. All notices, requests, claims, demands, and other communications hereunder shall be in writing and shall be given (and shall be deemed to have been duly given upon receipt) by delivery in the manner contemplated by the PPA, addressed as follows:

(a) if to Company as provided in the PPA

(b) if to Guarantor: _____

Attn:
Phone: (____) _____
Fax: (____) _____

with a copy to: _____

Attn:
Phone: (____) _____
Fax: (____) _____

or to such other address(es) as the person to whom notice is given may have previously furnished to the others in writing in the manner set forth above.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered to Company as of the day and year first above written.

[Name of Guarantor]

By: _____

EXHIBIT G-3

FORM OF ESCROW AGREEMENT

This Escrow Agreement ("Agreement") is entered into and effective this ___ day of _____, _____ by and among _____ ("Seller"), _____ ("Company") and _____ ("Escrow Agent").

RECITALS

WHEREAS, Seller and Company are parties to a Power Purchase Agreement dated _____ (the "PPA"), pursuant to which Seller agrees to build and operate an electric generating facility in _____ (the "Facility") and to sell energy from the Facility to Company. Capitalized terms used but not otherwise defined herein shall have the meanings ascribed to them in the PPA; and

WHEREAS, Section 11.1 of the PPA requires Seller to provide security in favor of Company in amounts set forth in the PPA up to a total of **[Trade Secret Data Begins...
...Trade Secret Data Ends]**; and

WHEREAS, Seller has elected to establish and deliver funds (the "Escrow Funds") into an escrow account with Escrow Agent to meet its PPA security obligations, and Seller, Company and Escrow Agent agree to enter into this Agreement to define the terms of that escrow account.

NOW, THEREFORE, in consideration of the foregoing and the mutual covenants and other consideration set forth in this Agreement and the PPA, and other good and valuable consideration, the receipt and adequacy of which is hereby acknowledged, the parties agree as follows:

AGREEMENT

1. Appointment of Escrow Agent. On the terms, and subject to the conditions, set forth in this Agreement, Seller and Company hereby appoint Escrow Agent as their agent and custodian to hold, invest and distribute the Escrow Funds and all interest and investment earnings thereon (the "Escrow Interest") in accordance with this Agreement. To the extent any Escrow Interest accrues during the term of this Agreement, such Escrow Interest shall be added to but shall not be included as part of the principal amount of the Escrow Funds except as set forth in Section 5.
2. Delivery of Funds to Escrow Agent.

- a. Seller shall deposit with Escrow Agent an amount equal to \$_____ (the "Escrow Total") on or before [_____] / [the date required by the PPA].
 - b. Escrow Agent shall retain and disburse the Escrow Funds pursuant to the terms of this Agreement. The execution and full performance of this Agreement by Seller and Escrow Agent, and retention and disbursement by Escrow Agent of the Escrow Funds pursuant to the terms hereof, fully satisfies Seller's initial obligations under Section 11.1 of the PPA to establish and maintain the Security Fund. Escrow Agent shall hold the Escrow Funds under the terms of this Agreement and distribute the Escrow Funds only in accordance with Section 5.
 - c. The Escrow Funds shall, for all purposes, be considered property of Seller unless and until distributed to Company in accordance with this Agreement. To protect Company prior to such distribution, Seller hereby grants to Company a first priority security interest in all of Seller's right, title and interest in and to the Escrow Funds held under this Agreement for the purpose of securing Seller's obligations under the PPA. However, any release of any portion of the Escrow Funds to Seller or Company in accordance with this Agreement shall act as an automatic termination of Company's security interest in the Escrow Funds so released. Seller authorizes Company to file such financing statements and other documents as Company reasonably deems necessary or advisable to protect Company's rights in the Escrow Funds. Each party will sign such documents (including upon the request of Company a control agreement), provide such information, send such notices and take such other actions as any other party reasonably requests to consummate more effectively the intent and purpose of the parties under this Section 2(c).
3. Investment. Escrow Agent shall hold and invest the Escrow Funds only in accordance with the terms of this Agreement. At the written direction of Seller, Escrow Agent shall invest and reinvest the Escrow Funds in cash or one or more of the following short-term securities: a money-market fund, short-term treasury obligations, investment-grade commercial paper and other liquid investment-grade investments with maturities of three (3) months or less. All investments of the Escrow Funds shall be held by, or registered in the name of, Escrow Agent or its nominee. All Escrow Interest and investment income earned on the Escrow Funds shall accrue for the benefit of, and be taxable to, Seller.
 4. Distributions of Escrow Funds by Escrow Agent. Escrow Agent shall hold the Escrow Funds until instructed or otherwise required to deliver the same or any portion thereof in accordance with Section 5.
 5. Distributions.

- a. Escrow Interest. Once Escrow Funds being held by Escrow Agent reach the Escrow Total, Seller may be paid Escrow Interest earned on the Escrow Funds at times and amounts in Seller's discretion as long as the amount of the Escrow Funds does not, as a result, become less than the Escrow Total.
 - b. Release at End of Term; Substitution of Security. After the full and final satisfaction of all of Seller's obligations under the PPA, any Escrow Funds remaining with Escrow Agent after all deductions for any damages or other allowed charges made by Company, and all accrued Escrow Interest, shall be released to Seller. If Seller provides a letter of credit or other security under the PPA in form and substance as required by the PPA to secure Seller's obligations to Company prior to the expiration or termination of the PPA, then all Escrow Funds and Escrow Interest in excess of the amount necessary to maintain the Security Fund under the PPA shall be released to Seller upon the delivery to Company of such effective letter of credit or security mechanism as permitted by the PPA.
 - c. Escrow Claims by Company. During the term of the PPA, Company may draw all or any portion of the Escrow Funds to the extent necessary to recover amounts due and owing to Company pursuant to the PPA that are not the subject of a good faith dispute. Each claim against the Escrow Funds under this Agreement shall be made by Company by delivering to Escrow Agent a certificate, in substantially the form of Exhibit A attached hereto, specifying the nature of the claim (a "Claim Certificate"). A copy of each Claim Certificate shall also be delivered to Seller contemporaneously with provision to Escrow Agent. Escrow Agent shall pay to Company the amount of Escrow Funds set forth in the Claim Certificate, in accordance with the Claim Certificate, on the third Business Day after it receives the Claim Certificate.
 - d. Regulations of the Comptroller of the Currency. Company and Seller acknowledge that regulations of the Comptroller of the Currency grant Company and Seller the right to receive brokerage confirmations of any security transactions as they occur. Company and Seller specifically waive such notifications to the extent permitted by law, and Seller will receive monthly cash transaction statements that will detail all investment transactions.
6. Rights and Obligations of Escrow Agent.
- a. Duties.
 - i. Escrow Agent hereby accepts its obligations under this Agreement and represents that it has the legal power and authority to enter into this Agreement and to perform its obligations hereunder. Escrow Agent agrees that all Escrow Funds held by Escrow Agent under

this Agreement shall be segregated from all other property held by Escrow Agent and shall be identified as being held in connection with this Agreement. Segregation may be accomplished by appropriate identification on the books and records of Escrow Agent. Escrow Agent's documents and records with respect to the transactions contemplated by this Agreement shall be available for examination by authorized representatives of Company and Seller. Escrow Agent will deliver to Company and Seller written statements not less than quarterly summarizing any activity with respect to the Escrow Funds (including the amount of interest and earnings thereon) and detailing the balance of the Escrow Funds.

- ii. This Agreement may be terminated by a writing executed by all of Company, Seller and Escrow Agent.
 - iii. In the event that this Agreement is scheduled to expire or terminate during the term of the PPA, and Seller has not provided security pursuant to the PPA required to replace this Agreement, Company may draw the entire balance of Escrow Funds, up to the Escrow Total, within five (5) Business Days of the scheduled expiration or termination date, and without regard to any objection asserted by Seller, provided Company holds the Escrow Funds it draws in escrow until the earlier of (i) the date Seller provides adequate replacement security in compliance with the PPA, or (ii) the date Company is entitled to draw and retain all or any portion of the Security Fund under the PPA.
 - iv. Seller will provide immediate notice to Company in the event that the amount of Escrow Funds at any time falls below the Escrow Total.
- b. No Other Duties. Escrow Agent shall not have any duties or responsibilities under this Agreement except as expressly set forth herein.
- c. Escrow Fee. Escrow Agent shall be entitled to receive solely from Seller (a) \$_____ annually (pro-rated for any partial year) on each anniversary of this Agreement as compensation for its regular services as escrow agent under this Agreement and (b) reimbursement for all reasonable and necessary out-of-pocket expenses incurred by Escrow Agent in fulfilling its obligations under this Agreement, including, without limitation, reasonable fees and disbursements of legal counsel. Such compensation and reimbursement obligations under this Section 6.c(b) shall be paid from time to time as incurred. In no circumstance will Company have any obligation to pay any amount to Escrow Agent arising out of or under this Agreement, except for actual damages sustained by Escrow Agent that have been directly caused by Company's sole negligence or intentional tortious misconduct.

- d. Resignation of Escrow Agent. Escrow Agent may at any time resign by giving thirty (30) days advance written notice of such resignation to Company and Seller. Upon such resignation, Escrow Agent shall not be discharged from its obligations under this Agreement until (a) a successor escrow agent, as mutually agreed on by Seller and Company, shall have been appointed, (b) the successor escrow agent shall have executed and delivered an Escrow Agreement in substantially the form of this Agreement and (c) all Escrow Funds then held by Escrow Agent under this Agreement shall have been delivered to such successor escrow agent.
 - e. Liability of Escrow Agent. Escrow Agent shall not be liable for any action taken in accordance with the terms of this Agreement, including, without limitation, any distribution of the Escrow Funds in accordance with Section 5, as long as the action was taken in good faith. Escrow Agent shall not be liable for any other act or failure to act under or in connection with this Agreement, except for its own negligence or intentional tortious misconduct. Seller and Company agree to indemnify, defend and hold Escrow Agent harmless from and against all claims, causes of action, costs, judgments, losses and damages arising out of or related to this Agreement, except for any such claims, causes of action, costs, judgments, losses or damages arising from or related to any breach of this Agreement by Escrow Agent or negligent or intentional tortious actions or omissions of Escrow Agent.
 - f. Reliance on Documentary Evidence. Escrow Agent shall be entitled to rely on any written notice, certificate, affidavit, letter, document or other communication that is reasonably believed by Escrow Agent to be genuine and to have been signed or sent by the proper party or parties, and on statements contained therein, without further inquiry or investigation. Notwithstanding anything to the contrary in this Agreement, Escrow Agent may act on any written instructions given jointly by Company and Seller.
 - g. Interpleader. If Company and Seller shall disagree about the interpretation of this Agreement, or about the rights and obligations or the propriety of any act contemplated by Escrow Agent hereunder, then Escrow Agent may, within its reasonably exercised discretion, file an action of interpleader in the appropriate court of competent jurisdiction and deposit all of the applicable Escrow Funds with such court.
7. Termination of Agreement. Unless terminated earlier by a writing executed by all of Company, Seller and Escrow Agent, this Agreement shall continue through, and terminate on, the earlier of: (i) the date on which all obligations of Seller under the PPA have been fully satisfied; or (ii) the date on which all of the Escrow Funds shall have been paid to Company pursuant to the terms of this Agreement.

8. Taxes. Taxes on distributions of the Escrow Funds shall be paid by Seller.
9. Notices. All notices and other communications (including all certificates delivered pursuant to Section 5) under this Agreement by Company or Seller to Escrow Agent shall be delivered contemporaneously to the other parties in the same manner as provided to Escrow Agent. All notices and other communications under this Agreement shall be given in writing and shall be personally delivered, sent by telecopier or facsimile transmission or sent to the applicable parties at their respective addresses indicated in this Section 9 by registered or certified U.S. mail, return receipt requested and postage prepaid, or by private overnight mail courier service, as follows:

If to Seller, to:

Attention: _____
Phone: _____
Fax: _____

If to Company:

Manager, Structured Purchases
Xcel Energy Services Inc.
1800 Larimer Street, Suite 1000
Denver, CO 80202
Phone: (303) 571-7714
Fax: (303) 571-7002

If to Escrow Agent, to:

Attention: _____
Phone: _____
Fax: _____

or to such other person or address as any party shall have specified by notice in writing to the other parties. If personally delivered, such communication shall be deemed delivered upon actual receipt; if sent by telecopier or facsimile transmission, such communication shall be deemed delivered the day of the transmission, or if the

transmission is not made on a Business Day, the first Business Day after transmission (and sender shall bear the burden of proof of delivery); if sent by overnight courier pursuant to this Section 9, such communication shall be deemed delivered upon receipt; and if sent by U.S. mail pursuant to this Section 9, such communication shall be deemed delivered as of the date of delivery indicated on the receipt issued by the relevant postal service or, if the addressee fails or refuses to accept delivery, as of the date of such failure or refusal.

10. Miscellaneous.

- a. Captions. All titles, subject headings, section titles and similar items are provided for the purpose of reference and convenience and are not intended to be inclusive, definitive or to affect the meaning of the contents or scope of the Agreement.
- b. No Third-Party Beneficiary. No provision of this Agreement is intended to nor shall it in any way inure to the benefit of any customer, property owner or other third party, so as to constitute any such person a third-party beneficiary under this Agreement, or of any one or more of the terms hereof, or otherwise give rise to any cause of action in any person not a party hereto.
- c. Integration; Amendment. This Agreement constitutes the entire agreement among the parties relating to the transactions described herein and supersedes any and all prior oral or written understandings. No amendment, addition to or modification of any provision hereof shall be binding on the parties, and no party shall be deemed to have waived any provision or any remedy available to it unless such amendment, addition, modification or waiver is in writing and signed by a duly authorized officer or representative of the applicable party or parties.
- d. Governing Law. The Agreement is made in the State in which the Facility is located and shall be interpreted and governed by the laws of such State or the laws of the United States, as applicable.
- e. Good Faith and Fair Dealing; Reasonableness. The parties agree to act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this Agreement. Unless expressly provided otherwise in this Agreement, (i) whenever this Agreement requires the consent, approval or similar action by a party, such consent, approval or similar action shall not be unreasonably withheld or delayed, and (ii) whenever this Agreement gives a party a right to determine, require, specify or take similar action with respect to matters, such determination, requirement, specification or similar action shall be reasonable.
- f. Severability. Should any provision of this Agreement be or become void, illegal or unenforceable, the validity or enforceability of the other

provisions of this Agreement shall not be affected and shall continue in force. The parties will, however, use their reasonable best endeavors to agree on the replacement of the void, illegal or unenforceable provisions with legally acceptable clauses that correspond as closely as possible to the sense and purpose of the affected provision and this Agreement as a whole.

- g. Cooperation. The parties agree to cooperate reasonably with each other in the implementation and performance of this Agreement. Such duty to cooperate shall not require any party to act in a manner inconsistent with its rights under this Agreement.
- h. Execution in Counterparts and By Facsimile Transmission. This Agreement may be executed in two (2) or more counterparts and by different parties on separate counterparts, all of which shall be considered one and the same agreement and each of which shall be deemed an original. This Agreement may be executed and delivered by facsimile, and the parties agree that such facsimile execution and delivery shall have the same force and effect as delivery of an original document with original signatures.

[This space intentionally left blank.]

IN WITNESS WHEREOF, the undersigned have caused this Agreement to be duly executed as of the date first set forth above.

Dated: _____ **(Seller)**

By: _____

Name: _____

Its: _____

Dated: _____ **(Company)**

By: _____

Name: _____

Its: _____

Dated: _____ **(Escrow Agent)**

By: _____

Name: _____

Its: _____

EXHIBIT A TO ESCROW AGREEMENT

ESCROW

CLAIM

CLAIM CERTIFICATE

TO: _____

This Claim Certificate is issued pursuant to that certain Escrow Agreement, dated as of _____, 2010, by and among Company, Seller and you, as Escrow Agent (the "Agreement"). Capitalized terms used but not otherwise defined in this Claim Certificate shall have the meaning ascribed to them in the Agreement.

The undersigned representative of Company hereby certifies that Company is entitled to receive Escrow Funds in the amount of \$_____ pursuant to the terms of the Agreement and the PPA, due to the following (generally): _____

_____.

Accordingly, subject to the terms of the Agreement, you are hereby instructed to distribute, on the third Business Day after your receipt of this Claim Certificate if you have not received written notice from the Seller that the disbursement is the subject of a good faith dispute, the sum of \$_____ from the Escrow Funds to the undersigned by wire transfer to the following account:

Bank: _____
Account: _____
Routing Number: _____

Date: _____, 20____

(Company)

By: _____
Name: _____
Title: _____

EXHIBIT H

OPERATING STANDARDS

(A) Dispatchability Requirements. Each unit shall be capable of providing:

1. Automatic Generation Control (AGC) from the EMCC;
2. A minimum regulating range 30 MW per unit in automatic load regulation capacity;
3. Continuous response to EMCC pulsing at a minimum rate of five percent of the capacity available at the time per minute over the regulating range of increasing MW of the Facility dispatched and five percent of the capacity available at the time per minute over the regulating range of decreasing MW of the Facility dispatched; and
4. A low load point for the regulating range of the Facility, which is equal to or less than the Minimum Loading level for operation with AGC.

(B) Operations Requirements. The following operations requirements will apply throughout the Term.

1. Operations Log. Seller shall maintain an hourly operation log that identifies real-time unit operating information including: current level of unit capacity availability, planned and unplanned maintenance outages or deratings, circuit breaker operation and any other significant events related to the operation of the unit. Any changes in the generating status or availability of the unit shall be reported immediately to the EMCC operator by telephone.

2. Telemetry/Generation Load Control Requirements. Company shall design, purchase, own, install and test, in accordance with the procedures set forth in this Exhibit, the telemetry equipment, generation load control equipment and the circuits from the Facility demark to the EMCC. Generation load control equipment is defined as the equipment and associated hardware necessary to interpret the request for a generation load change and provide a signal to the governor of Seller's equipment. Seller shall in no way constrict or modify the generation load change signal path without review and written authorization by Company. The telemetry and generation load equipment is to provide the following: instantaneous net MW and MVAR levels, control status (available for automatic generation control), load regulation range limits, remote pulsing circuit, and any other parameters deemed necessary by Company. Seller shall install at the Facility MW and MVAR indicating equipment that reflects the identical MW and MVAR values as those telemetered to the EMCC.

3. Periodic Verification of Compliance. Subsequent to the initial verification of AGC compliance as provided for above, Company shall have the

right, at any time and without prior notice to Seller, to verify the continued compliance of such requirements. The subsequent tests will be performed by Company on an as needed basis with a frequency of not greater than every two years. Seller will be notified of test results for any noncompliance.

(C) Automatic Generation Control Availability. Company will monitor Seller's ability to be automatically dispatched. It is the expectation of the Parties that the Facility will be available for automatic generation dispatch during 100% of the Facility's on-line hours (excluding periods of failure of Company's telemetry, during which Seller will manually be dispatched by Company).

* * *

EXHIBIT I

LENDER CONSENT PROVISIONS

In the event Seller collaterally assigns its rights hereunder to the Facility Lender as security, any related Lender Consent will contain provisions substantially as follows:

1. Seller and Company will neither modify nor terminate the PPA other than as provided therein, without the prior written consent of the Facility Lender.
2. The Facility Lender shall have the right, but not the obligation, to do any act required to be performed by Seller under the PPA, and any such act performed by the Facility Lender shall be as effective to prevent or cure a default as if done by Seller itself.
3. If Company becomes entitled to terminate the PPA due to an uncured Event of Default by Seller, Company shall not terminate the PPA unless it has first given notice of such uncured Event of Default to the Facility Lender and has given the Facility Lender the same cure period afforded to Seller under Section 12.1 of the PPA, plus an additional 30 Days beyond Seller's cure period to cure such Event of Default; *provided, however*, that if the Facility Lender requires possession of the Facility in order to cure the Event of Default, and if the Facility Lender diligently seeks possession, the Facility Lender's additional 30-Day cure period shall not begin until foreclosure is completed, a receiver is appointed or possession is otherwise obtained by or on behalf of the Facility Lender.
4. Neither the Facility Lender nor any other participant in the Facility Debt shall be obligated to perform or be liable for any obligation of Seller under the PPA until and unless any of them assumes possession of the Facility through the exercise of the Facility Lender's rights and remedies.
5. Any party taking possession of the Facility through the exercise of the Facility Lender's rights and remedies shall remain subject to the terms of the PPA and shall assume all of Seller's obligations under the PPA, both prospective and accrued, including the obligation to cure any then-existing defaults capable of cure by performance or the payment of money damages. In the event that the Facility Lender or its successor assumes the PPA in accordance with this paragraph 6, Company shall continue the PPA with the Facility Lender or its successor, as the case may be, substituted wholly in the place of Seller.
6. Within ninety (90) Days of any termination of the PPA in connection with any bankruptcy or insolvency Event of Default of Seller, the Facility Lender (or its successor) and Company shall enter into a new power purchase agreement on the same terms and conditions as the PPA and for the period that would have been remaining under the PPA but for such termination.

EXHIBIT J

PREDICTED NET HEAT RATE DEGRADATION ADJUSTMENT

The Predicted Net Heat Rate (P), as used in Section 8.4, shall be calculated as follows:

P = initial Predicted Net Heat Rate × (1 + HRAF), where

HRAF = Predicted Net Heat Rate Adjustment Factor, as provided in Tables J-1 and J-2

Prior to the first major maintenance on the combustion turbine (CT) at the Facility, Table J-1 shall be used to calculate the HRAF for the Facility. The total fired hours on the CT shall be used to look-up the HRAF in the table. Linear interpolation shall be used to calculate the HRAF used to calculate the Predicted Net Heat Rate, between break points.

After the first major maintenance on the CT and after each following major maintenance, Table J-2 shall be used to calculate the HRAF. The total fired hours on the CT since the most recent major maintenance shall be used to look-up the HRAF in Table J-2. Linear interpolation shall be used to calculate the HRAF used to calculate the Predicted Net Heat Rate, between break points.

Major maintenance normally occurs after 48,000 hours of CT operation. Factors such as number of trips and a low average number of fired hours per start can accelerate the major maintenance schedule.

Table J-1:

Total combustion turbine fired hours (as of end of billing period)	Predicted Net Heat Rate Adjustment Factor (HRAF)
0	0%
5,000	1.13%
10,000	1.44%
15,000	1.63%
20,000	1.78%
25,000	2.17%
30,000	2.56%
35,000	2.87%
40,000	3.06%
45,000	3.22%
>48,000	3.25%

Table J-2:

Total combustion turbine fired hours (since last major maintenance) (as of end of billing period)	Predicted Net Heat Rate Adjustment Factor (HRAF)
0	1.70%
5,000	2.83%
10,000	3.14%
15,000	3.33%
20,000	3.48%
25,000	3.54%
30,000	3.58%
35,000	3.61%
40,000	3.65%
>45,000	3.70%

EXHIBIT K

FUEL QUALITY SPECIFICATIONS

See attached pages taken from the tariffs of the Upstream Pipeline and Northern Border Pipeline Company. The specifications are subject to change by the Upstream Pipeline and Northern Border Pipeline Company in accordance with the modification requirements of the tariff and other applicable regulations.

Northern Border Pipeline Company
FERC Gas Tariff
Second Revised Volume No. 1

PART 6.5
6.5 - GT&C
Quality of Gas
v.1.0.0 Superseding v.0.0.0

6.5 QUALITY OF GAS

1. Quality Standards of Gas Received by Company.

Company may refuse to accept gas which does not conform to the following specifications:

- (a) The gas shall not contain sand, dust, gums, crude oil, impurities or other objectionable substances which may be injurious to pipelines or may interfere with the transmission of the gas.
- (b) The gas shall have a hydrocarbon dew-point less than -5 degrees F at 800 psia, -10 degrees F at 1000 psia, or -18 degrees F at 1100 psia, or such higher dew point approved by Company as, without treatment by Company, may be compatible with the operating conditions of Company's pipeline.
- (c) The gas shall not contain more than 0.3 grains of hydrogen sulphide per Ccf.
- (d) The gas shall not contain more than 2 grains of total sulphur per Ccf.
- (e) The gas shall contain not more than 0.3 grains of mercaptan sulphur per Ccf, or such higher content as, in Company's judgment, will not result in deliveries by Company to Shippers of gas containing more than 0.3 grains of mercaptan sulphur per Ccf.
- (f) The gas shall not contain more than 2 percent by volume of carbon dioxide.
- (g) The gas shall not have a water vapor content in excess of 4 pounds per MMcf.
- (h) The gas shall be as free of oxygen as it can be kept through the exercise of all reasonable precautions and shall not in any event contain more than 0.4 percent by volume of oxygen.
- (i) The gas shall have a gross heating value of not less than 967 Btu per cf.

2. Quality Tests.

At each Point of Receipt of a Shipper, Company shall cause tests to be made, by approved standard methods in general use in the gas industry, to

determine whether the gas conforms to the quality specifications set out in Section 6.5 paragraph 1 hereof. Such tests shall be made at such intervals as Company may deem reasonable, and at other times, but not more often than once per day, at the request of any Shipper.

Issued: December 13, 2010
Effective: July 28, 2010

Docket No. RP10-1004-001
Accepted: August 16, 2011

Northern Natural Gas Company
FERC Gas Tariff
Sixth Revised Volume No. 1

Original Sheet No. 281

GENERAL TERMS AND CONDITIONS

44. QUALITY

All gas shall conform to the following specifications:

- a) The gas shall be commercially free from objectionable odors, solid matter, dust, gums and gum-forming constituents, or any other substance which might interfere with the merchantability of the gas, or cause injury to or interference with proper operation of the lines, meters, regulators, or other appliances through which it flows.
- b) Oxygen - less than or equal to 0.2% by volume.
- c) Hydrogen sulfide - less than or equal to 1/4 grain/Ccf.
- d) Total Sulphur - less than or equal to 20 grains/Ccf.
- e) Carbon Dioxide - less than or equal to 2.0% by volume.
- f) Water - less than or equal to 6 pounds/MMcf.
- g) Heating Value - greater than or equal to 950 Btu/Cubic Foot.
- h) The temperature shall be less than or equal to 120 degrees Fahrenheit.

If any gas received by Northern shall fail at any time to conform to the specifications set forth above, Northern may refuse to accept delivery pending correction by the other party. Northern may, on a basis that is not unduly discriminatory, elect to accept gas which fails to meet specifications.

Issued on: September 24, 2010

Effective on: September 24, 2010

EXHIBIT L

MAINTENANCE REQUIREMENTS

(A) Seller shall provide a schedule of the expected Scheduled Outages/Deratings for the Facility (“Maintenance Schedule”) for the first Commercial Operation Year at least ninety (90) Days prior to COD. Thereafter, at least ninety (90) Days prior to each successive Commercial Operation Year, Seller shall: (1) submit an annual Maintenance Schedule for the next successive Commercial Operation Year; each scheduled outage shall include the start time and expected duration of the outage; and (2) supply a long-term Maintenance Schedule that will encompass the following four Commercial Operation Years. Any change in the annual Maintenance Schedule, by either Party, shall be furnished to the other Party with advance notice. Minimum advance notice of any change in or extension of the Maintenance Schedule is as follows based on the original total duration:

<u>Scheduled Outage Expected Duration</u>	<u>Advance Notice Required</u>
(1) Less than 2 Days	at least 24 hours
(2) 2 to 5 Days	at least 7 Days
(3) Major overhauls (over 5 Days)	at least 90 Days

(B) Scheduled Maintenance Energy.

1. If the Facility is comprised only of combustion turbine units, Company shall provide Seller the opportunity to use 360 MWh of Scheduled Maintenance Energy (“SME”) per MW of Net Capability during each Commercial Operation Year as a credit towards Seller’s Capacity Availability Factor (“CAF”) pursuant to the payment calculation specified in Section 8.1, *provided, however, that* such SME is scheduled in advance with Company pursuant to this Exhibit L and approved in writing by Company prior to Seller’s use of such SME. If Seller uses less than 360 MWh of SME per MW of Net Capability in a Commercial Operation Year, Seller may carry over for use in the next Commercial Operation Year unused SME as additional credit towards Seller’s CAF during the next Commercial Operation Year, *provided, however, that* such SME carried over shall also be scheduled in advance with Company pursuant to this Exhibit L and approved in writing by Company prior to Seller’s use of such SME, and *provided, further, that* the total SME per MW of Net Capability that may be accumulated by Seller for use in any Commercial Operation Year, beginning with the second Commercial Operation Year and including carry over SME, shall not exceed 672 MWh of SME per MW of Net Capability for that Commercial Operation Year. SME may not be advanced from future Commercial Operation Years.

2. If the Facility is comprised of combustion turbine and steam turbine units operating in combined cycle mode, Company shall provide Seller the opportunity to use 456 MWh of Scheduled Maintenance Energy (“SME”) per MW of Net Capability during each Commercial Operation Year as a credit towards Seller’s

Capacity Availability Factor (“CAF”) pursuant to the payment calculation specified in Section 8.1, *provided, however, that* such SME is scheduled in advance with Company pursuant to this Exhibit L and approved in writing by Company prior to Seller’s use of such SME. If Seller uses less than 456 MWh of SME per MW of Net Capability in a Commercial Operation Year, Seller may carry over for use in the next Commercial Operation Year unused SME as additional credit towards Seller’s CAF during the next Commercial Operation Year, *provided, however, that* such SME carried over shall also be scheduled in advance with Company pursuant to this Exhibit L and approved in writing by Company prior to Seller’s use of such SME, and *provided, further, that* the total SME per MW of Net Capability that may be accumulated by Seller for use in any Commercial Operation Year, beginning with the second Commercial Operation Year and including carry over SME, shall not exceed 720 MWh of SME per MW of Net Capability for that Commercial Operation Year. SME may not be advanced from future Commercial Operation Years.

EXHIBIT M

ESC EVENT ADJUSTMENT

(A) If during some or all of an event (an “ESC Event”) deemed an “Energy Emergency” by the applicable “Reliability Coordinator” under NERC Standard EOP-002-3, or its replacement, the entire Facility either (i) is fully available, (ii) is deemed fully available pursuant to Section 8.1 and this Section, and/or (iii) is subject to a scheduled maintenance outage eligible for SME under Section 10.2 (an “SME Outage”), Seller shall be entitled to a positive ESC Event Adjustment with respect to such ESC Event in the amount of $NC \times DE \times ABF$, where consistent with NERC Standard EOP-002-3, or its replacement, Capacity and Energy Emergencies:

NC = the Net Capability of the Facility expressed in kW;

DE = the number of hours during the ESC Event, during which the Facility is fully available (excluding the number of hours (if any) during the ESC Event when the Facility was subject to an SME Outage); and

ABF = the applicable Availability Bonus Factor:

EEA-1:	<i>[Trade Secret Data Begins... Secret Data Ends]</i>	<i>...Trade</i>
EEA-2:	<i>[Trade Secret Data Begins... Secret Data Ends]</i>	<i>...Trade</i>
EEA-3:	<i>[Trade Secret Data Begins... Secret Data Ends]</i>	<i>...Trade</i>

(B) If some or all of the Facility is not fully available (other than due to SME Outages) during some or all of an ESC Event, Seller shall be subject to a negative ESC Adjustment with respect to such ESC Event in the amount of $ANC \times DO \times ARF$, where:

ANC = the Affected Net Capability of the Facility (i.e. the portion of the Net Capability subject to the outage), expressed in kW;

DO = the hours during which the Net Capability of the Facility is not fully available due to causes other than SME Outages; and

ARF = the applicable Availability Reduction Factor:

EEA-1:	<i>[Trade Secret Data Begins... Secret Data Ends]</i>	<i>...Trade</i>
EEA-2:	<i>[Trade Secret Data Begins... Secret Data Ends]</i>	<i>...Trade</i>
EEA-3:	<i>[Trade Secret Data Begins... Secret Data Ends]</i>	<i>...Trade</i>

provided, however, that with respect to each Commercial Operation Year, in no event shall aggregate net ESC Event Adjustment under this Section exceed:

(i) an amount equal to 200 hours x EEA-1 x NC, with respect to EEA-1 Events during such Commercial Operation Year;

(ii) an amount equal to 50 hours x EEA-2 x NC, with respect to EEA-2 Events during such Commercial Operation Year; or

(iii) an amount equal to 25 hours x EEA-3 x NC, with respect to EEA-3 Events during such Commercial Operation Year.

(C) In determining whether the Facility is “fully available” for purposes of an ESC Event (in contrast to Section 8.1), the availability of the Facility will be adjusted to Reference Conditions.

EXHIBIT N

FACILITY OPERATIONAL INFORMATION

General

The information contained in this Exhibit is indicative only and merely the Seller’s best representation of the operational characteristics of the Facility at the time of execution of the Agreement. Updates to the information are possible based on final design and construction and environmental permitting.

Heat Rate information

Unit Loading	Summer Load (MW)	Summer Net Heat Rate (Btu/kWh) HHV	Winter Load (MW)	Winter Net Heat Rate (Btu/kWh) HHV
[Trade Secret Data Begins...]				
Low operating point (Minimum Load)				
Minimum Loading Starting Point				
25% of base capacity				
50% of base capacity				
75% of base capacity				
100% of base capacity				
100%, plus supplemental capacity				

...Trade Secret Data Ends]

Summer reference conditions are at an ambient temperature of 90°F dry-bulb, and 68% relative humidity. Winter reference conditions are at an ambient temperature of 6°F dry-bulb, and 68% relative humidity.

Start Up information

Start Type	Duration (mins)	Fuel Consumed (MMBtu)	Energy Produced (MWh)
[Trade Secret Data Begins...]			
Warm			
Cold			
Lag			

...Trade Secret Data Ends]

A warm start is defined as less than or equal to 48 hours off-line and a cold start is when the steam turbine is off-line for more than 48 hours. A lag start refers to a start when the MEC I Facility is already operating.

The startup is initiated at “flame on” at the plant and ends when the unit is at Minimum Load Starting Point.

Shutdown and Minimum On/Off line

Minimum Up Time (minimum time between generator breaker close and re-open): 4 hours.

Minimum Down Time (minimum time Facility must be off-line before restarting): 60 minutes, unless the steam turbine generator has been placed on turning gear, in which case the Facility must be off-line for 4 hours.

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Direct Testimony and Schedules
Paul B. Johnson

Before the North Dakota Public Service Commission
State of North Dakota

Application of Northern States Power Company
for an Advance Determination of Prudence for a Power Purchase Agreement with
Mankato Energy Center, LLC for Approximately 345 MW of Combined-Cycle Gas
Generation

Case No. PU-15-_____
Exhibit____(PBJ-1)

Resource Need and Calpine Project PPA Testimony

February 13, 2015

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Table of Contents

I.	Introduction	1
II.	Resource Need	2
III.	Calpine Project PPA	11
IV.	Prudence of Calpine Project PPA	16
V.	Prudence of Proposed Resource Portfolio (Black Dog, Calpine, and Geronimo)	27

Schedules

Resume

Schedule 1

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I. INTRODUCTION

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Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Paul B. Johnson. I am Director of Resource Planning and Bidding for Xcel Energy.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since July 2014 in the area of resource planning. In my current role, I am responsible for the direction and oversight of electric Resource Planning for the five-state integrated Northern States Power Company system (NSP System), which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan.

My responsibilities include directing the development of resource plans, working closely with modeling to complete the analyses required for those plans. I also oversee the development and execution of Request for Proposals (RFP), the modeling for asset acquisition assessments, and provide long-term pricing guidance for purchased power negotiations. In addition, I lead the effort to provide resource analysis and planning guidance for regulatory filings, information requests needed by various departments, and NSP executives. My resume is provided as Exhibit____(PBJ-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss the capacity resource need that is the basis for the Company's proposal to enter into a 20-year power purchase agreement (PPA) with Mankato Energy Center, LLC, an affiliate of Calpine Corporation (Calpine

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1 Project PPA), including the factors and analysis that went into determining the
2 resource need. I also discuss the terms of the Calpine Project PPA, and our
3 analysis of the PPA’s costs and benefits for our ratepayers.
4

5 Q. PLEASE SUMMARIZE YOUR TESTIMONY.

6 A. The Company performs a rigorous analysis to estimate its resource needs
7 many years into the future, using econometric and other assumptions and
8 variables as a basis for its determinations. I identify in my testimony the
9 challenges and difficulties in accurately assessing future generation capacity
10 requirements, and provide the range of probable need we face based on the
11 best available information we have. Company Witness Mr. Kurtis J. Haeger
12 discusses in his Direct Testimony the variability in our demand forecasts that
13 contributed to the the Company’s determination of a capacity need of 150-500
14 MW by the end of the decade.
15

16 I then discuss the terms of the Calpine Project PPA, highlighting known risks
17 and the steps taken to mitigate those risks. I also provide a detailed analysis of
18 the costs and benefits of the PPA for our ratepayers to aid the Commission in
19 its determination of the PPA’s prudence.
20

II. RESOURCE NEED

21
22
23 Q. HOW IS THE COMPANY’S RESOURCE NEED DETERMINED?

24 A. The Company’s assessment of resource need is based on three primary
25 factors: (1) peak demand forecast; (2) required reserve margins; and (3) the
26 maximum generation capability of existing resources. The peak demand
27 forecast is based on an econometric model using a combination of variables,

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1 including weather-normalized native energy requirements and peak producing
2 weather by month. The reserve margins are based on the reserve margin
3 calculations used by the Midwest Independent System Operator, Inc., (MISO),
4 the regional transmission organization to which the Company belongs.
5 Finally, the maximum generation capability of existing resources is based on
6 NSP System operational data.

7
8 In addition to analyzing peak demand, we also forecast our total annual energy
9 requirements based on projected sales and transmission line losses, which
10 includes the impact of Demand-Side Management on our total sales. This not
11 only contributes to our assessment of a capacity need, but also allows us to
12 assess the type of resource that will best meet our energy needs, that is,
13 whether the best option in light of capacity and energy needs is the addition of
14 a baseload, intermediate, or peaking resource to our system or some
15 combination of those types of resources.

16
17 Q. WHAT IS THE COMPANY'S NEED?

18 A. The Company's need is 150-500 MW by 2019/2020, based on our updated
19 Fall 2011 forecast (Fall 2011 Forecast). This forecast updated the initial
20 forecasting included in our 2010 Resource Plan. Augmented with information
21 from the Company's Spring 2013 forecast, the Fall 2011 Forecast is the
22 forecast that was used in our advance determination of prudence application
23 for Black Dog Unit 6 and Red River Valley Units 1 and 2 (Case No. PU-13-
24 194 (Gas CTs ADP Case)).

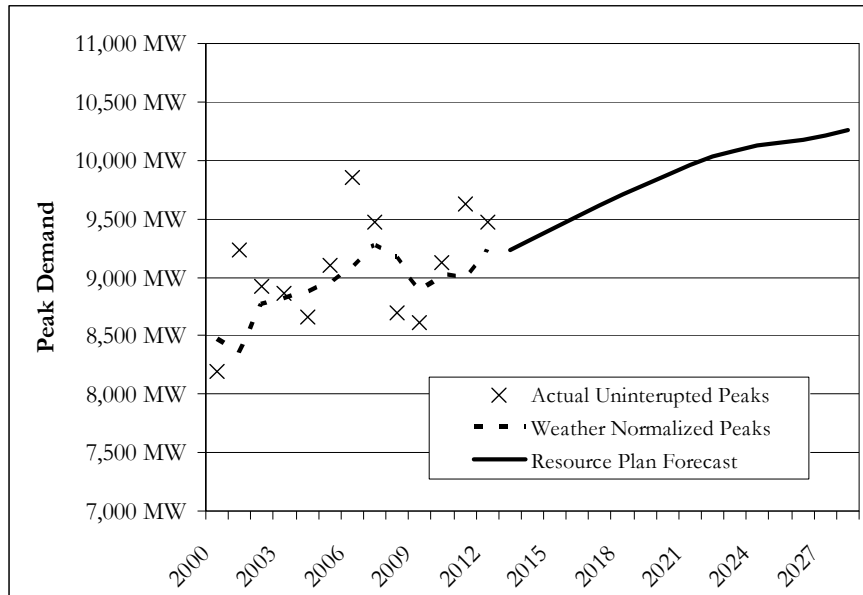
25
26 Q. PLEASE DESCRIBE THE COMPONENTS OF THE FALL 2011 FORECAST.

27 A. Figure 1 provides the Fall 2011 Forecast's peak demands. As shown in Figure

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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**

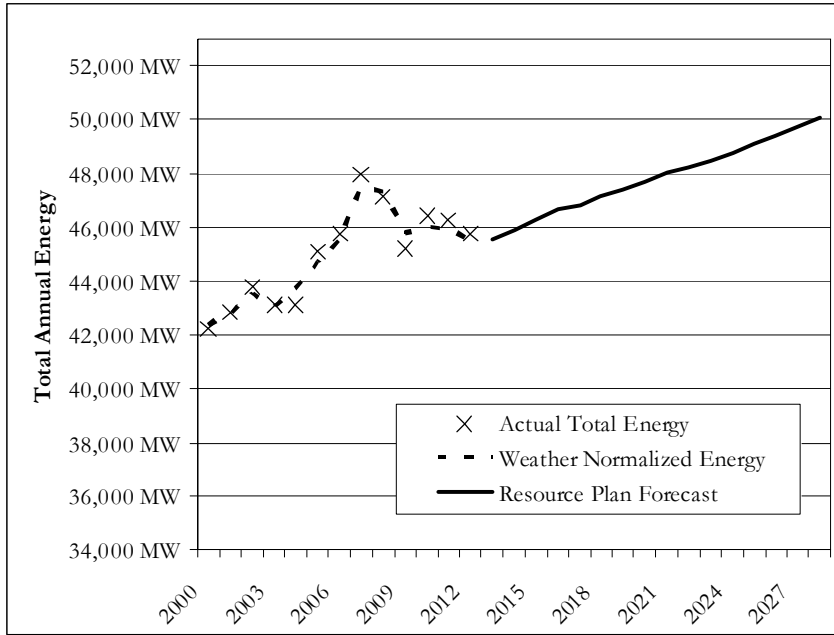


Our total annual energy forecast is shown in Figure 2. The Fall 2011 Forecast assumed an average growth rate from 2013 to 2020 of 0.7 percent.

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**Figure 2:
NSP Historic and Forecasts Total Annual Energy**



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Our Fall 2011 Forecast also took into consideration the reserve margin calculations specified by 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 around 500 MW by 2019-2020, as shown in Table 1.

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**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
<u>x 1+RM%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>
= Total Obligation	9,786	9,885	9,977	10,076	10,170	10,255
<u>Resources</u>	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	-	-	-	-	-
<u>Load Management*</u>	<u>1,145</u>	<u>1,153</u>	<u>1,157</u>	<u>1,153</u>	<u>1,149</u>	<u>1,145</u>
Total	9,943	9,917	9,823	9,757	9,727	9,724
Long (Short)	157	32	(154)	(319)	(443)	(532)

* Includes reserves

4

As shown in Table 1, our Fall 2011 Forecast identified a capacity need of 153 MW in 2017, growing to 532 MW in 2020.

5

6

7

Q. PLEASE DESCRIBE THE UNCERTAINTY RELATING TO CHANGES IN HOW MISO CALCULATES RESERVE MARGINS.

8

9

A. The way MISO calculates the generation reserve margins necessary to ensure system reliability has been subject to on-going change. Starting in 2013, MISO's reserve margin calculation for individual utility systems will change to reflect the utility's peak demand *at the time of the region's peak*, rather than the utility's own peak. The Company's demand at the MISO peak has varied

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1 substantially, and has not been coincident with MISO's in five of the last eight
2 summer seasons – averaging approximately five percent lower than our own
3 peak.

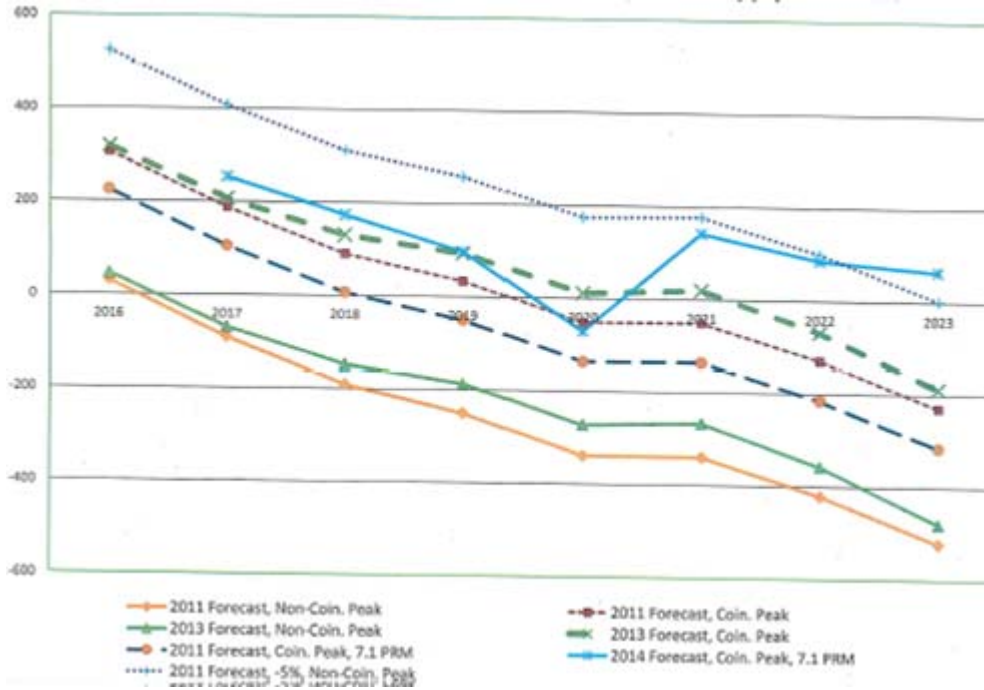
4
5 Because our peak has not been coincident with MISO's, this methodology
6 change reduces our reserve obligation. For 2013, the Company's reserve
7 margin was approximately 200-300 MW lower than what we used in 2010
8 Resource Plan analysis. Relatively small changes in coincidence factors,
9 combined with adjustments in MISO's UCAP capacity calculations and
10 adjustments in MISO's annual loss of load expectation calculations, can swing
11 reserve requirements on our system measurably. However, it is not clear at
12 this time how reserve calculations might change between now and the 2017-
13 2019 time period for which we currently have identified resource needs.

14
15 Figure 3 below illustrates the impact of this uncertainty by applying the
16 coincident and non-coincident methodologies to various demand forecasts
17 considered during our 2010 Resource Plan proceedings. The figure shows
18 that very small changes can result in material swings in the required amount of
19 capacity.

20

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**Figure 3:
Impact of Coincident and Non-Coincident Peak Methodologies on
Resource Plan Need Forecasts**



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

Q. WHAT IS THE MOST RECENT FORECAST OF THE COMPANY'S NEED IN ITS 2015 RESOURCE PLAN?

A. The Company's recently filed Resource Plan shows a modest amount of excess capacity (between 1 and 2.5 percent) from 2015 through 2018 and virtually no excess capacity on a system-wide basis in 2019 and 2020. In 2021, the system then regains a small amount of 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

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1 assumed supply portfolio is modest given that normal forecast variability can
2 result in demand swings of 200 MW (2 percent) or more.

3
4 Q. WHAT ARE THE COMPANY’S OPTIONS FOR MANAGING THIS RISK OF CHANGES
5 IN CUSTOMER LOAD FROM WHAT IS FORECASTED?

6 A. The normal variability we have experienced between load projections and
7 actual results in recent years indicates it is appropriate to acquire additional
8 generation as a hedge. While we recognize that we could potentially purchase
9 short-term capacity from the MISO voluntary capacity market at then-
10 prevailing rates for any capacity shortfall, we must also consider that existing
11 and proposed retirements of baseload units in the MISO footprint may result
12 in a shortfall of capacity across the footprint leading to higher capacity prices
13 in the MISO voluntary short-term capacity market. Prudent planning includes
14 balancing the risk of exposure to the capacity market in the next five years
15 against the cost of building additional capacity in the 2019/2020 time-frame,
16 which will be necessary by 2024 in any event.

17
18 Our 2015 Resource Plan includes a scenario that reflects all of our currently
19 contemplated resources. This includes: (1) the 98 MW creditable capacity
20 (187 MW nameplate) of the solar portfolio which is the subject of Case No.
21 PU-14-810; (2) the 278 MW creditable capacity (345 MW nameplate) of the
22 Calpine Project PPA; (3) the up-to 71 MW creditable capacity (100 MW
23 nameplate) of the Geronimo Solar PPA; (4) the 207 creditable capacity of
24 the Black Dog 6 combustion turbine unit (215 MW nameplate); (5) a new
25 short-term (four-year) 75 MW capacity exchange with Manitoba Hydro; and
26 (6) additional resources contemplated in our 2015 Resource Plan. If all of this
27 contemplated new generation is deployed, it will result in a system surplus in

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1 the 2019-2020 timeframe of about 6 to 7 percent (550 MW in 2019 and 685
2 MW in 2020) and address our resource need in 2024.

3
4 Table 2 provides a summary of this analysis on a system-wide basis:

**Table 2:
System Capacity Forecast (MW)
(2014 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	529	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									

9
10 Q. WHAT IS THE IMPACT IN NORTH DAKOTA?

11 A. We prepared a similar analysis showing the same information on a North
12 Dakota load-allocated basis. The following Table 3 provides the output of
13 that analysis:

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**Table 3:
North Dakota Allocated System Capacity Forecast (MW)
(2014 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 statistical 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.

III. CALPINE PROJECT PPA

Q. PLEASE DESCRIBE THE CALPINE PROJECT PPA?

A. The 20-year PPA will provide approximately 345 MW (nameplate) of capacity and associated energy to our system from a new natural-gas combined-cycle unit to be added to Calpine’s existing 375 MW Mankato Energy Center (MEC), located in Mankato, Minnesota. The new 345 MW CC unit (with an accredited capacity of 278 MW) will be incorporated into the existing

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1 footprint of MEC. The Company currently has a 20-year PPA with Calpine
2 for all of the capacity and associated energy produced from the existing
3 375 MW CC unit at MEC, which expires in 2026.

4
5 Q. WHAT ARE THE PRINCIPAL TERMS OF THE CALPINE PROJECT PPA?

6 A. The PPA has a kW-month price for capacity and MWh price for energy. The
7 proposed capacity and energy prices escalate annually after the first year of
8 operation. We anticipate that the new C unit at MEC will achieve commercial
9 operation in 2018 or 2019. Adding the resource to the NSP System in June
10 2018 would result in the addition of approximately **[TRADE SECRET**
11 **BEGINS** **TRADE SECRET ENDS]** of revenue requirements in
12 2018 and **[TRADE SECRET BEGINS** **TRADE SECRET**
13 **ENDS]** in 2019.

14
15 The payment and other terms in the PPA generally mirror the same terms in
16 the Company's existing MEC PPA with Calpine. By using the existing MEC
17 PPA payment provisions in the new Calpine Project PPA, the administrative
18 burden associated with using two different payment calculations and billing
19 processes for the two PPAs was avoided. It also avoids the risk that
20 unforeseen differences in the payments made and received under different
21 calculation formulas for the two PPAs could have unintended consequences
22 on how the parties choose to schedule, operate, and properly calculate
23 payments for each facility.

24
25 Q. PLEASE DESCRIBE THE RISKS OF THE PPA.

26 A. The Calpine Project PPA had risks with respect to (1) potential need to delay
27 or terminate the PPA; (2) transmission interconnection costs; (3) capacity

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1 accreditation; (4) environmental costs; (5) financial security; (6) construction
2 and operational issues; and (7) governmental/third-party authorizations and
3 approvals.

4
5 Q. PLEASE DESCRIBE HOW THE COMPANY MITIGATED THE DELAY/TERMINATION
6 RISKS?

7 A. The Company negotiated options to delay or terminate its PPA in the event
8 future circumstances warrant doing so. In the event it is deemed prudent to
9 delay the PPA, the Company may at its discretion delay the facility's COD
10 from 2018 to 2019 subject to the increased capacity and energy prices
11 associated with the new COD, and must also pay for Calpine's demobilization
12 and re-mobilization costs. The Company may also terminate the PPA, paying
13 Calpine for its unrecovered costs, as well as a breakage fee in addition to the
14 unrecovered costs. Total termination fees could be substantial as shown in
15 the PPA, provided as Trade Secret Exhibit___(KJH-1), Schedule 2.

16
17 Q. WHAT IS THE RISK WITH RESPECT TO TRANSMISSION INTERCONNECTION COST?

18 A. The PPA reflects Calpine's proposal that the Company pay for all
19 transmission costs to interconnect the expansion Facility to the grid. Calpine
20 has estimated that these costs will run from \$650,000 to \$1.5 million, and the
21 Company has agreed to accept the risk of such costs.

22
23 Q. WHAT IS THE CAPACITY ACCREDITATION RISK AND HOW HAS IT BEEN
24 MITIGATED?

25 A. It appears there are transmission network upgrades that must be made before
26 MISO can accredit the expansion capacity as a Capacity Resource available to
27 the Company, and the completion schedule for these upgrades is beyond

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1 Calpine’s control. The Company agreed to Calpine’s proposal that it may elect
2 to delay COD by one year upon timely notice to the Company that Calpine
3 cannot achieve accreditation by COD. This allows the Company to obtain
4 from another source the capacity credit it needs for the year the PPA is
5 delayed, although the cost of the capacity credit will be subject to the
6 prevailing market conditions. Absent such timely notice, Calpine must
7 achieve accreditation by COD, and failure to do so is an Event of Default
8 subject to specific cure provisions designed to keep the Company whole in all
9 events.

10
11 Q. PLEASE DESCRIBE THE COMPANY’S MITIGATION OF THE RISKS ASSOCIATED
12 WITH ENVIRONMENTAL COSTS.

13 A. Calpine proposed that the Company be liable for all costs resulting from
14 future regulation of all types of emissions. The Company strongly objected to
15 its customers incurring these unknown costs, and Calpine accepted the
16 Company’s position that it will only accept the conditional risk of carbon
17 emission regulation consistent with the Company’s assumption of that risk as
18 stated in the Company’s model PPA used to guide negotiations.

19
20 Q. HOW DOES THE PPA MITIGATE THE FINANCIAL SECURITY RISK OF THE PPA?

21 A. The Calpine Project PPA establishes a pre-COD and post-COD security fund
22 to protect the Company generally from the range of financial risks associated
23 with the PPA. The Company also negotiated a provision requiring Calpine
24 upon completion of the new CC unit to obtain a subordinated mortgage on
25 the facility for the benefit of the Company.

26
27 Q. PLEASE DESCRIBE THE MITIGATION OF THE PPA’S CONSTRUCTION AND

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1 OPERATIONAL RISKS.

2 A. The Company negotiated the payment of liquidated damages for each day that
3 Calpine fails to meet COD for its new CC unit at the Mankato plant site due
4 to reasons other than its failure to achieve MISO accreditation of the facility
5 as a Capacity Resource. In addition, the PPA includes other protective
6 measures such as specific performance, step-in rights, actual damages, and
7 termination. The Company also accepted Calpine’s proposal that it be
8 allowed to provide energy from an alternative generation source post COD in
9 the event that more than 50 MW of the capacity of its new CC unit becomes
10 unavailable due to a forced outage. This holds the Company harmless from a
11 shortfall in meeting its energy needs in the face of a significant outage of the
12 new CC unit.

13

14 Q. WHAT ARE THE RISKS ASSOCIATED WITH GOVERNMENTAL AND OTHER THIRD
15 PARTY APPROVALS AND AUTHORIZATIONS?

16 A. These risks include obtaining required governmental permits and approvals,
17 obtaining required third-party contracts that are necessary for the project to be
18 completed, and internal approvals of regulatory revisions of the PPA’s terms.
19 The PPA’s “conditions precedent” provide a mechanism for terminating the
20 PPA if these are not obtained. For Calpine, these conditions include
21 obtaining an air permit, a site permit and interconnection agreement, and
22 approval of the final PPA by the Calpine Board of Directors, all by specified
23 dates.

24

25 For its part, the Company must obtain timely approval of the PPA from this
26 Commission. The Company’s obligation is to seek an approval order from
27 the Commission no later than 15 business days after the execution of the

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1 PPA, or the Company shall be deemed to have waived its right to seek such
2 approval. The PPA provides that the Company may terminate the PPA if it
3 has not received the requested approval from the Commission by April 1,
4 2015, but can delay the April 1 deadline to July 1, 2015 with the consequence
5 that the PPA's commercial operation date is delayed until 2019.

6
7 **IV. PRUDENCE OF CALPINE PROJECT PPA**

8
9 Q. WHAT FACTORS SHOULD BE CONSIDERED IN DETERMINING THE PRUDENCE OF
10 THE CALPINE PROJECT PPA?

11 A. The two principal factors are (1) whether the type, size, and timing of the
12 Calpine Project PPA capacity is appropriate to meet the Company's identified
13 need, and if so, (2) does it effectively meet that need at a reasonable cost. Mr.
14 Haeger addresses our need in his Direct Testimony, and I address how the
15 type, size, and timing of the Calpine Project PPA effectively meets that need
16 at a reasonable cost.

17
18 Q. HOW DID THE COMPANY ANALYZE WHETHER THE TYPE, SIZE, AND TIMING OF
19 THE CALPINE PROJECT PPA MEETS THE COMPANY'S NEED?

20 A. To ensure that sufficient resources were evaluated to cover the high end of
21 potential capacity needs identified in our Fall 2011 Forecast, the Company
22 used Strategist to model portfolios consisting of different combinations of the
23 resource proposals submitted in the Minnesota competitive acquisition
24 process (CAP) docket (MPUC Docket No. E002/CN-12-1240), ranging from
25 358 MW to 636 MW. These proposals represented peaking and intermediate
26 resources.

27

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1 In addition to the 345 MW combined cycle unit proposed by Calpine to be
2 added in 2017 or 2018, we modeled the Company's proposal to add a single
3 combustion turbine unit at its Black Dog plant in 2017, 2018, or 2019, and
4 two combustion turbine units at a new Red River Valley plant site near
5 Hankinson, North Dakota in 2018 and 2019. We also modeled Invenergy
6 Thermal Development, LLC's proposal to add a single 179 MW natural gas
7 CT at its existing Cannon Falls, Minnesota plant, and two additional 179 MW
8 CTs located at a new plant site near Hampton Corners, Minnesota. The
9 proposed Invenergy units would be placed in service in either 2017 or 2018.
10 Our modeling also included Geronimo Energy's proposal for distributed solar
11 generation, with an aggregate capacity of up to 100 MW, to be placed in
12 service by the end of 2016 to take advantage of the federal Investment Tax
13 Credit. And our modeling included Great River Energy's proposal for a three-
14 year purchase of either 100 MW or 200 MW of resource capacity credits only,
15 no energy or generation would be associated with the purchase.

16
17 The peaking resources were modeled as dispatchable units with heat rate
18 curves that reflect the units' efficiency at various generation levels. Each unit's
19 maximum capacity was modeled as approximately 230 MW in the winter and
20 215 MW in the summer. The fuel costs were based on the forecasted costs of
21 natural gas at the Ventura hub, with transportation cost adders included to
22 reflect the expected cost at each of the sites. A scenario to reflect a large
23 natural gas, combined-cycle unit was also run through the Strategist model.
24 Natural gas, combined -cycle generators have higher capital expenditures for
25 construction, but are more fuel efficient when generating.

26
27 Q. WHAT WERE THE RESULTS OF THIS ANALYSIS?

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1 A. Based on our Strategist modeling, the Company determined Black Dog Unit 6
2 was the most cost-effective resource on a Present Value Societal Cost (PVSC)
3 basis, as required under Minnesota regulations, as evidenced by the fact that it
4 was included in each of the top 20 resource plans identified in the Company’s
5 analysis. The most effective portfolios identified by Strategist consisted of
6 Black Dog Unit 6 being deployed in conjunction with either the Calpine
7 Project or the Invenergy Cannon Falls project, on a PVSC basis. Our
8 modeling did not conclude that the Geronimo Solar Project was a least-cost
9 resource.

10
11 Q. DID THE COMPANY ANALYZE THESE RESOURCES ON A PRESENT VALUE
12 REVENUE REQUIREMENTS BASIS?

13 Yes, we used the Strategist resource planning model again to evaluate our
14 resource selection consistent with the requirements of this Commission. We
15 used the same assumptions and forecast information as we did in the
16 Minnesota CAP proceeding but expressed our modeling results as a Present
17 Value of Revenue Requirements (PVRR) comparison, consistent with North
18 Dakota law. Table 4 provides the results of this analysis.

**Table 4
PVSC v. PVRR of Portfolios (\$millions)**

Resource Combination	2013-2050 PVSC (\$millions)	2013-2050 PVRR with ND Assumptions (\$millions)
Calpine PPA + Black Dog 6	\$45,368	\$39,180
Black Dog 6 + RRV 1&2	\$45,404	\$39,198
Cost/(Savings) of Calpine PPA + Black Dog 6	(\$36)	(\$18)

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1 Our cost analysis shows that the acquisition of the 485 MW combination of
2 Black Dog Unit 6 (207 MW accredited capacity) and Calpine Project PPA (278
3 MW accredited capacity) is less expensive on both a PVRR and PVSC basis
4 than the 621 MW combination of Black Dog Unit 6 and the two Red River
5 Valley Units (207 MW accredited capacity each).

6
7 Q. DOES THE ADDITIONAL \$18 MILLION COST ASSOCIATED WITH THE EXTRA
8 136 MW OF THE BLACK DOG AND RED RIVER VALLEY CT'S PRESENT MORE
9 VALUE THAN THE COMBINATION OF BLACK DOG UNIT 6 WITH THE CALPINE
10 PROJECT PPA?

11 A. I do not believe it does. As I discuss in more detail below, the addition of
12 278 MW of combined cycle capacity to our system through the Calpine
13 Project PPA provides the Company significant operational flexibility as it
14 faces the loss of intermediate and baseload capacity over the next decade as a
15 result of retiring generation units and expiring PPAs.

16
17 Q. DID THE COMPANY DO OTHER ANALYSES OF THE COST-EFFECTIVENESS OF
18 THE CALPINE PROJECT PPA?

19 A. Yes. While the above analyses show that the Calpine Project PPA is a
20 reasonable and prudent decision based on the alternatives available to us
21 through the CAP docket, we also believe it is appropriate to present the most
22 recent vintage information on the cost effectiveness of the Calpine Project
23 PPA so that the benefits and the burdens of acquiring this resource can be
24 appropriately evaluated by the Commission. To do this, we used the 2014
25 load forecast and resource availability assumptions included in our 2015
26 Resource Plan recently filed with the Commission, which is our most recent
27 load forecast update.

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Q. PLEASE DESCRIBE THIS ADDITIONAL ANALYSIS THE COMPANY CONDUCTED ON THE CALPINE PROJECT PPA.

A. As the Commission knows, 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 Calpine Project PPA. For purposes of this analysis we considered the PPA in isolation rather in combination with the other proposed new generators.

MISO generally dispatches combined cycle intermediate load units on an economic basis during peak to support and balance baseload units and intermittent resources. The energy produced by an economically dispatched CC unit generally displaces a similar amount of more expensive energy that would have been produced by the Company or otherwise purchased elsewhere. The Strategist analysis identifies a displacement of approximately 18,300,000 MWh of more expensive generation, which accounts for the differences in the cost of system operations with and without the Calpine Project PPA.

We also conducted various “sensitivity tests” to evaluate how the Calpine Project PPA will affect system costs under different circumstances. The sensitivities analyzed include the effect on system costs if one assumes (1) the Fall 2011 Forecast of capacity need relied upon by the MPUC (i.e., a need of 150-500 MWs in the 2017-2019 timeframe), (2) no MISO market purchases

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1 available to supplement system resources (Markets Off), and (3) higher and
2 lower gas costs.

3
4 As Table 5 below shows, our analysis estimates that the overall system cost of
5 energy with the Calpine Project PPA added to our system (on a PVRR basis
6 without considering any costs associated with CO2 emissions or externalities)
7 is \$11 million lower than it would be without the this resource being on our
8 system.

**Table 5:
Total System Cost With/Without Calpine Project PPA**

Changes in PVRR Cost (\$millions)	Base Case Using ND Assumptions	2012 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions
Base Case Using ND Assumptions	\$44,949	\$49,279	\$41,260	\$50,050	\$45,957	\$51,971
Base Case Using ND Assumptions with Calpine Project PPA	\$44,937	\$49,257	41,271	\$50,010	\$45,883	\$51,944
Net Cost/(Savings)	(\$11)	(\$22)	\$10	(\$40)	(\$74)	(\$27)

12
13 Our analysis also concluded that the addition of the Calpine Project PPA
14 reduces system costs for all sensitivities except when the price of gas is low, as
15 shown in the above table.

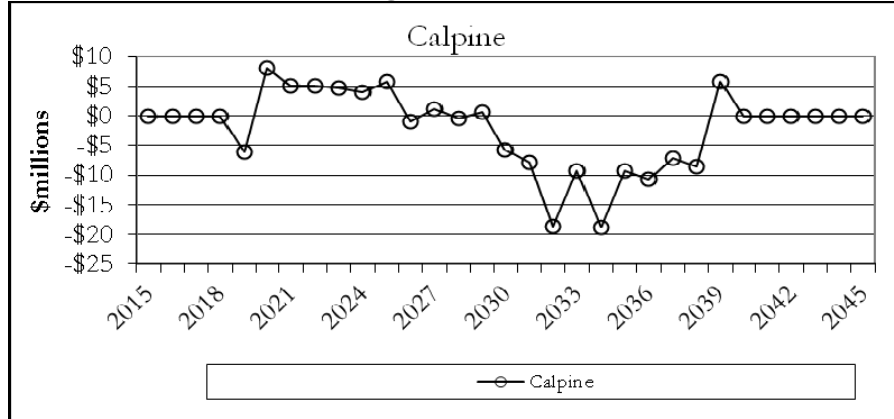
16
17 Q. HOW ARE THE CALPINE PROJECT PPA COSTS SPREAD OVER TIME?

18 A. Figure 4 below illustrates the year-over-year annual net costs or savings of the
19 Calpine Project PPA during its 20-year life, which results in the net \$11
20 million savings identified in the table above. Except for 2019, the cost of
21 energy over the first 10 years of the PPA does not offset its capacity cost,
22 while energy savings in the second 10 years of the PPA more than offset its

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1 capacity cost to achieve the overall net savings of \$11 million over the PPA’s
2 20-year term.

3
4 **Figure 4:**
5 **Annual Net System Costs (Savings) with Calpine Project PPA Compared to**
6 **Base Case Using North Dakota Assumptions**

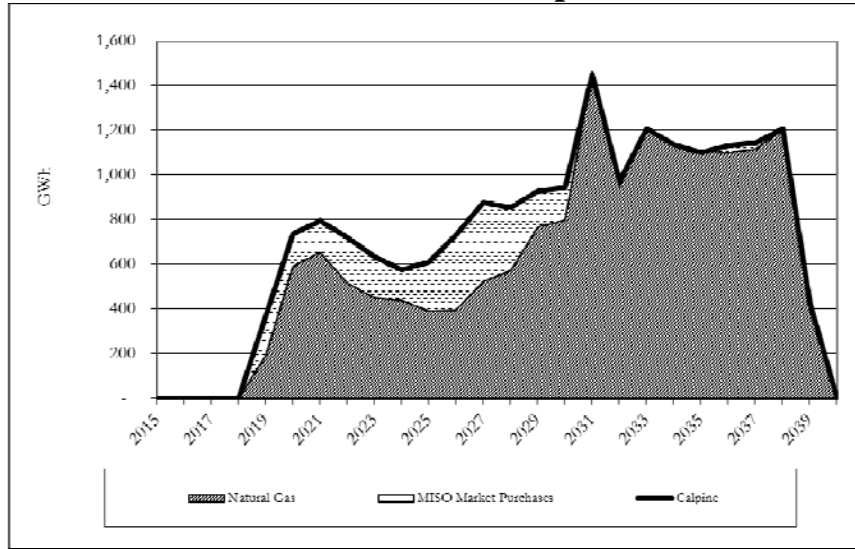


7
8
9 Q. WHAT IS THE PROFILE OF THE 18,300,000 MWH OF MORE EXPENSIVE
10 GENERATION THAT THE CALPINE PROJECT PPA DISPLACES?

11 A. Figure 5 below illustrates the results of the Strategist dispatch simulations for
12 the Base Case using North Dakota assumptions (i.e., a “Markets On” scenario
13 with no additional renewable generation selected by Strategist and no
14 externalities or carbon cost). In this scenario Strategist may choose to
15 purchase market energy to meet system needs. Over the 20-year term of the
16 PPA, approximately 87 percent of the Calpine Project PPA’s generation
17 displaces other natural gas generation, and 13 percent displaces market energy.

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**Figure 5:
Calpine Project PPA – Displaced Energy for Base Case Using
North Dakota Assumptions**



Q. WHAT IMPACTS WILL THE CALPINE PROJECT PPA HAVE ON CUSTOMER RATES?

A. While the Calpine Project PPA represents the addition of a combined cycle unit to our system, the customer rate impacts will be mitigated when spread across the entire NSP System because the System is so large. As shown in Table 6 below, our Strategist dispatch simulation forecasts for most years show the rate impact of the Calpine Project PPA (energy and capacity costs) to be significantly offset by avoiding higher priced fossil fuel energy and market energy purchases.

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**Table 6:
Calpine Project PPA Impacts
(¢/kWh)**

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Base Rates	0.000	0.000	0.000	0.000¢	0.041	0.070	0.071	0.072	0.073 0	0.073 0	0.074
Fuel Clause	0.000	0.000	0.000	0.000	0.036	0.077	0.088	0.080	0.073	0.069	0.074
Avoided Fuel/Mkt Purchases	0.000	0.000	0.000	0.000	-0.091	-0.129	-0.148	-0.140	-0.134	-0.133	-0.135

As shown in Table 7 below, the initial net rate impact of the Calpine Project PPA is estimated to be 0.014¢ per kWh in 2019, rising to 0.019¢ per kWh in 2020, and then dropping and staying at or below 0.012¢ per kWh through 2024 before rising back up to 0.014¢ per kWh again in 2025.

**Table 7:
Calpine Project PPA Net Rate Impacts (10 Years)**

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
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

Q. DID THE COMPANY IDENTIFY ANY OTHER BENEFITS OF THE CALPINE PROJECT PPA?

A. Yes. The Calpine Project PPA provides value in light of a reduction in baseload and intermediate resources on our system in the next decade due to unit retirements and expiring PPAs. The PPA also provides value with respect to controlling the risk of emerging environmental regulations.

Q. PLEASE DESCRIBE THE VALUE OF THE CALPINE PROJECT PPA WITH RESPECT TO THE REDUCTION OF BASELOAD AND INTERMEDIATE CAPACITY RESOURCES

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1 ON THE COMPANY’S SYSTEM.

2 A. From 2015-2030, the NSP System will experience significant reductions in
3 energy resources due to power contracts expiring without extension or
4 renewal. Several potential key changes include the following:

- 5 • 2023- Blue Lake Units 1-4 cease operation (153 MW)
- 6 • 2025- Manitoba Hydro contracts expire (850 MW)
- 7 • 2026- Cottage Grove combined cycle contract expires (262 MW)
- 8 • 2027- Mankato combined cycle contract expires (357 MW)

9

10 Further, in the 2030-2035 timeframe, the Company faces the potential
11 retirement of three baseload nuclear units, along with Sherco Units 1 and 2
12 retiring after a 60 year operating life. Altogether this suggests that a significant
13 proportion of our baseload generation may be retired within 15 to 20 years.
14 These five generating units have been the backbone of the NSP System for
15 many years and have formed the foundation to provide low cost and highly
16 reliable service to our customers.

17

18 With respect to Sherco, there is the possibility that Unit 1 may be retired as
19 early as 2025, and we have included modeling in our 2015 Resource Plan to
20 identify system requirements in the case that occurs. The addition of the
21 Calpine PPA is a hedge against that possibility. Current technology suggests
22 that natural gas combined cycle units, along with additional renewable energy,
23 will be the likely candidates to replace the energy and capacity these units have
24 provided. As a result of the large potential exposure to add natural gas to our
25 system in the 2025 to 2035 timeframe, the Company must attempt to
26 minimize this exposure going into that timeframe. The addition of the
27 Calpine PPA in 2019 minimizes the Company’s exposure to this risk, allowing

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1 for greater flexibility to respond when our backbone baseload plants are
2 retired.

3
4 Q. PLEASE EXPLAIN HOW THE CALPINE PROJECT PPA MINIMIZES THE RISK
5 ASSOCIATED WITH THE DECLINE IN BASELOAD CAPACITY.

6 A. First, the Calpine PPA locks in very competitive pricing for natural gas
7 combined cycle generation for the next twenty years. Second, this
8 competitively priced capacity resource is capable of intermediate and baseload
9 operation, offering a flexible option to conservatively address the uncertainty
10 of our forecasted capacity need. In addition, the Calpine Project PPA is
11 capable of significant energy production that enhances system flexibility for a
12 variety of system outcomes.

13
14 Q. HOW DOES THE CALPINE PROJECT PPA MINIMIZE THE RISK ASSOCIATED WITH
15 EMERGING ENVIRONMENTAL REGULATIONS?

16 A. Despite our strategy of shifting our resource portfolio toward lower-emission
17 options while maintaining our focus on fuel diversity, affordability and
18 reliability, we continue to experience significant uncertainty surrounding
19 environmental regulation. Probably the biggest – and most uncertain – factor
20 is the EPA’s existing source GHG performance standard, known as the Clean
21 Power Plan or Section 111(d) Rules, which EPA expects to finalize in mid-
22 summer 2015. The final rule is likely to face legal challenges, which depending
23 whether or not the rule is stayed during litigation, may affect the timeline for
24 state plan development. If the Rule is not stayed, each state will draft plans
25 and submit them to EPA by 2016 to 2018, for approval by EPA one year
26 later; compliance will begin in 2020.

27

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1 While much remains unknown, it seems clear that the Rule will (1) put
2 increasing pressure on coal plants, possibly resulting in reduced utilization
3 levels or additional retirements; (2) likely increase generation from existing and
4 new natural gas plants; and (3) push us to continue adding renewable energy
5 resources and increasing energy efficiency efforts and associated investments.
6 The addition of the Calpine PPA hedges against these likely outcomes. It
7 constitutes intermediate capacity that can step in to support the NSP System
8 due to impacts the any future environmental regulation may have on our key
9 generating facilities, including our baseload coal units at the Sherburne County
10 Generating Station and our Allen S. King Plant.

11
12 **V. PRUDENCE OF PROPOSED RESOURCE PORTFOLIO**
13 **(BLACK DOG, CALPINE, AND GERONIMO)**
14

15 Q. DID THE COMPANY ANALYZE THE COSTS AND BENEFITS OF THE ENTIRE
16 RESOURCE PORTFOLIO IT IS PROPOSING?

17 A. Yes. To provide context for the Commission’s evaluation of this ADP
18 request, we conducted modeling that identifies the costs of various
19 combinations of the three resources we propose to acquire: Black Dog Unit
20 6, the Calpine Project PPA, and the Geronimo Solar PPA. Tables 8 and 9
21 below present the PVRR results of the specified combinations of resources,
22 and the results of the same sensitivity tests that we conducted for the Calpine
23 Project PPA.

24

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**Table 8:
PVRR Results (\$millions)**

<u>Scenarios</u>	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)**

<u>Scenarios</u>	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)

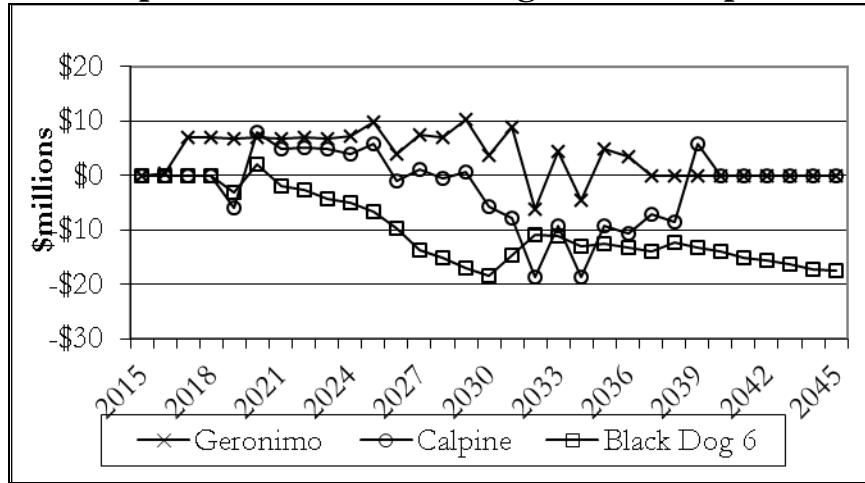
Notably, the addition of the Calpine Project PPA together with Black Dog Unit 6 provides the most Present Value of Revenue Requirements (PVRR) savings of the combinations provided. Further, the Geronimo Solar PPA in combination with the Calpine Project PPA and Black Dog Unit 6 provides a net reduction in the PVRR in all scenarios except the low gas case.

Q. WHAT IS THE AGGREGATE IMPACT OF ADDING THE THREE RESOURCES OVER TIME?

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

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**Figure 6:
Annual Net Costs (Savings) (without CO2)
Compared to Base Case using ND Assumptions**

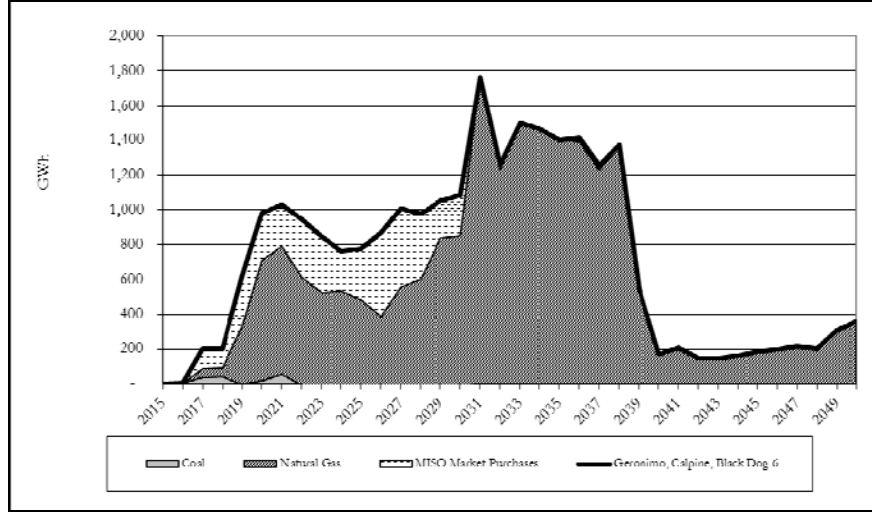


Q. WHAT IS THE PROFILE OF THE MORE EXPENSIVE ENERGY DISPLACED BY THE ADDITION OF BLACK DOG UNIT 6, THE CALPINE PROJECT PPA, AND THE GERONIMO PPA?

A. Figure 7 below illustrates the results of the Strategist dispatch simulations for the Base Case using 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.

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**Figure 7:
Strategist Simulations - Displaced Energy Base Case Using ND
Assumptions for combination of Geronimo, Calpine, and Black Dog 6
Projects**



As shown, the overall impact of adding all three resources on the operation of the NSP System is displaced natural gas generation.

Q. WHAT IS THE AGGREGATE RATE IMPACT OF ADDING BLACK DOG UNIT 6, THE CALPINE PROJECT PPA, AND THE GERONIMO PPA TO THE SYSTEM?

A. 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

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

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1 A. Yes, it does.

Paul B. Johnson
Director Resource Planning and Bidding
Northern States Power
411 Nicollet Avenue
Minneapolis, MN 55345
612-330-5656
[*paul.b.johnson@xcelenergy.com*](mailto:paul.b.johnson@xcelenergy.com)

PROFESSIONAL EXPERIENCE

Director Resource Planning and Bidding

July 2014 –Present

Xcel Energy, Minneapolis, MN

- Develop and direct the systems, processes and personnel required to prepare effective and prudent long term system plans for each of the four Xcel Energy operating utilities.
- Develop and direct the systems, processes and personnel required to conduct effective and fair power solicitation processes to procure needed power and energy to meet native load demand and energy requirements and achieve cost reductions in the Xcel supply portfolios.
- Direct acquisition of up to 800 MW per year of additional capacity and for management of the various state resource planning processes in a manner to fulfill requirements and meet company objectives meeting native load requirements and company asset growth goals.

Manager Power Supply Planning

March 2012—June 2014

Old Dominion Electric Cooperative (ODEC), Glen Allen, VA, a large G&T Cooperative serving 11 distribution cooperative members located in VA, MD and DE who serve over 1.3 million customers with a peak load of about 3000 MW.

- Directed long term power supply area of ODEC managing all ongoing power supply analysis, requests for proposals, PPA negotiations for renewable and thermal resources and planning analysis and issue or hot topic updates responsive to ODEC Board requests which meets monthly.
- Directed selection, implementation and ongoing management and updates of all planning models and data sources used for long term planning.
- Worked effectively and collaboratively with all areas of ODEC to successfully fulfill corporate and business unit objectives for current budget year.
- Actively develop staff providing growth opportunities within power supply planning and with other areas of ODEC.
- Kept abreast of developments and trends in PJM and electric industry and evaluate potential impact as a part of long term planning efforts and updates to executive management and Board members.

President, S&P Energy, LLC

October 2011--February 2012

I formed S&P Energy LLC October 2011 in response to interest by others in my network to work with other consulting firms and development companies with all aspects of renewable project development and marketing (permitting, interconnection, off-take prospects and contracting, RFP responses, etc.).

- Worked as contract consultant with Bridge Energy Group as key resource for interconnection report development and filing support for large Californian utility to the California ISO involving over 120 reports (November 2011 through January 2012)
- Pursued consulting contract negotiations for work with a couple renewable project developers and biomass fuel production facility developers.

Sr. Manager, Development North central and Eastern Regions

April 2009—May 2011

RES Americas, Minneapolis, MN, a national wind and solar project development and construction company. I have management responsibility of regional office in Minneapolis under Regional Vice

President Minneapolis Office has active project pipeline of nearly 2000 MW.

- Direct project management responsibility for development and power marketing of 300 MW Wind Project in southeastern, MN Successfully initiated and navigated permitting to advanced stage resulting in MPUC unanimous October 2010 approval of site permit and certificate of need. Led effort to successfully gain unanimous Mower County Commissioner approval of permits for two transmission routes and three substation sites. Provided direction and support for project interconnection options and study evaluation and effective and timely interaction with Midwest Independent System Operator (MISO) staff.
- As member of company-wide management team participated in 2010 effort to evaluate and refine RES Americas business strategy and identify key implementation efforts.
- Established and maintained project marketing relationships and RFP follow-up with electric utilities in MN, WI, IA, OH and TN.
- Actively monitored renewable market project development and sale opportunities which resulted in relationships with new power purchase prospects in upper Midwest and Eastern US.
- Led effort to evaluate potential biomass fuel opportunity and led effort to develop a biomass fuel business plan for generation market in US and Europe. This effort relied on extensive biomass fuel and biomass power market research.
- Identified and completed initial due diligence for potential acquisition of biomass fuel planting, harvesting and combustion technologies for utility-scale greenfield and retrofit biomass power generation projects.
- Completed preliminary work on strategic approach for wind project development in eastern US based on current and projected changes in renewable market and electric utility generation plans.

Several key positions with Minnesota Power, Duluth, MN June 1999—April 2009

An 1800 MW investor-owned electric utility serving 140,000 customers.

Renewable Energy Project Development Manager October 2006—April 2009

- Developed and led turbine 2008 purchase solicitation, screening and contract negotiation process which resulted in executed contract for 33 turbine project in North Dakota.
- Developed and gained management support for capital budget and project development plan for several 100 MW of wind generation development. Supported executive management's effort to secure budget and initial project approval.
- Initiated and continued to direct multi-year wind prospecting effort which resulted in met tower siting and installation on several project site in northeastern Minnesota. Prospecting effort also identified large area with high average winds within economic distance of grid interconnection. Oversaw successful wind option acquisition effort with sufficient land and wind rights to support substantial wind project development.
- Provided site control and project information necessary to maintain interconnection study process and avoid higher study costs.
- Developed and directed 2004 and 2007 All Source Request for Proposals through bid completeness, evaluation, short-list, contract negotiation and filing with state public utilities commission (all filed contracts approved).
- Successfully led negotiation team for four wind-based power purchase agreements totally 156 MW.
- Developed, maintains and directs implementation of renewable strategy responsive to corporate strategy and direction of key state and federal policies.
- Developed and managed relationships with major wind developers, turbine suppliers and regulators essential for continuing to increase wind portion of Minnesota Power renewable power supply.
- Managed hand-off to project construction team of permitted, sited projects with turbines.
- Provided liaison as needed with MP executive management, outside consultants and key landowners to resolve issues and keep wind generation project progress on schedule.

Strategic Initiatives—Project Leader

September 2002—October 2006

- Directed development and implementation of long term power supply request for proposals for renewable, bridge transactions and long term purchases; evaluation and PPA negotiation completion by mid-2005.
- Led multi-area effort to develop and maintain MP's long term plan and develop and defend MP's biennial 15-year Resource Plan filed in September 2004.
- Developed long term power sales responses to RFPs and manage post-bid submittal follow-up through buyer screening and short-list announcement
- Identified long term power market and generation technology developments, trends, events and provide assessment executive management.
- Led and manage multi-area generation strategy development to support executive management decisions.
- Managed long term generation asset sale process including buyer due diligence and definitive agreement development.
- Tracked and provided assessments of regional generation development and performance of existing regional generation.

Generation Development –Project Leader

June 1999—August 2002

- Managed internal generation development agreement compliance.
- Identified and screened generation development opportunities as key member of generation development team and lead project due diligence under executive management direction.
- Led effort to deploy and integrate price forecasting and generation opportunity evaluation tools into management decision processes.
- Monitored electric industry and key data sources for competitive intelligence and use this information to improve timing and focus of generation development.

ELECTRIC UTILITY INDUSTRY COMMITTEE LEADERSHIP OPPORTUNITIES

- Edison Electric Institute Renewables Committee. Committee developed policy proposals on federal renewable policy initiatives to reflect position of member investor-owned utilities)
- EPRI Storage and Renewables Task Force (Biomass/Waste Fuel Working Group Chair) Efforts resulted in gaining \$85 million DOE funding commitment to complete engineering and build first 100 MW biomass power using “whole tree energy” technology. Also chaired national biomass technology symposium jointly hosted by EPRI and DOE in Washington, DC.

EDUCATION

Bachelor of Science and Master of Arts Environmental Studies

Bemidji State University. Bemidji, MN

Completed extensive graduate studies in organic chemistry, ecology, macro/micro economics, environmental law, politics of pollution and many special topic research papers requiring peer defense. Degree was designed to prepare students to understand industrial environmental issues and regulatory requirements, pollution control and renewable technologies, law and associated environmental impacts. Served as graduate assistant in library and physics lab. Completed graduate internship with regional development commission providing technical support to environmental projects.