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April 17, 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: NORTHERN STATES POWER COMPANY REQUEST FOR APPROVAL OF AN ADVANCE DETERMINATION OF PRUDENCE FOR A 187 MW SOLAR PORTFOLIO
CASE NO. PU-14-810

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy, submits to the North Dakota Public Service Commission this Rebuttal Testimony in the above-referenced matter. The 187 MW Solar Portfolio consists of Purchase Power Agreements to purchase the output of the Marshall Solar project, located near Marshall, Minnesota; the MN Solar I project, located near Tracy, Minnesota; and the North Star Solar project, located near North Branch, MN.

An original and nine copies of the Rebuttal Testimony of Kurtis Haeger are being provided via Federal Express.

Please contact me if you have any questions regarding this filing.

Sincerely,

David H Sederquist

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

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Pre-filed Rebuttal Testimony and Schedules - Kurtis J. Haeger
Northern States Power Company
David Sederquist

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 187 MW Portfolio of Utility Scale Solar Resources

Case No. PU-14-810
Exhibit___(KJH-2)

**Rebuttal Testimony**

April 17, 2015

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## Schedules

## I. INTRODUCTION AND SUMMARY

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 Inc. In that role I coordinate the resource planning function for Northern States Power Company-Minnesota (NSP, Xcel Energy or the Company).

Q. HAVE YOU PROVIDED OTHER TESTIMONY ON THE TOPICS YOU ARE PROVIDING HERE?

A. Yes. On November 7, 2014, I submitted prefiled written Direct Testimony in this proceeding. That testimony provided the Commission with the Company's view of the resource planning context that supports granting an Advance Determination of Prudence (ADP) for this requested 187 MW solar portfolio resource addition.

I also submitted prefiled written Direct Testimony on February 13, 2015 in Case No. PU-15-095 (the Geronimo Solar PPA proceeding). My testimony in the Geronimo Solar PPA proceeding provides additional information about the Company's resource planning efforts and describes NSP's views on the desirability to plan conservatively to ensure sufficient generating capacity is and reasonable-cost energy in place to meet our customers' needs under all reasonable circumstances. In addition, that testimony provides discussion about the generation resource "Restack" concept, which arose in our settlement of the last rate case (Case No. PU-12-813) and which is currently being negotiated by the Company and Commission Staff.

Many of the issues addressed in my Direct Testimony in the Geronimo Solar PPA case are similar to the issues raised in this case. As a result, I have attached a copy of the public version my Direct Testimony (without Schedules) in that case as, Schedule 1 to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to the Direct Testimony of Commission Advocacy Staff member Mike Diller. Mr. Diller provides an important and valid perspective for the Commission to consider in planning for system additions in a multi-jurisdictional utility like the Company. Mr. Diller's testimony is helpful in that it provides a reasoned policy perspective on the timing and justification for the Company's resource additions to serve our North Dakota customers. However, that policy perspective carries with it certain implications and risks that should also be taken into account as the Commission considers the appropriate timing for adding resources under the circumstances.

My Rebuttal Testimony provides the Company's perspective on the issues raised by Mr. Diller. More specifically, I address the following:

- General resource planning concepts that influence the selection and timing of resource additions;
- The development and utilization of a planning reserve margin;
- The risks associated with reliance upon MISO as a backstop in the event of a capacity shortfall;
- The Company's need for additional resources at this time in light of current demand forecasts;
- The potential impact on NSP's integrated system arising from differing

public policy choices in the states we serve; and

- The implications if North Dakota chooses to have capacity direct-assigned to the jurisdiction rather than accept a pro-rata allocated share of the Company's integrated generation fleet.

My testimony also presents letter agreements for minor changes to the PPAs for the 187 MW solar portfolio.

Q. MR. DILLER SUMMARIZES HIS TESTIMONY WITH THE FOLLOWING CONCLUSION (PAGE 1:20-26):

> "NSP's North Dakota ratepayers do not need the proposed SP for generation capacity or the energy that these units would provide. The proposal does not represent least cost planning. Instead, the SP is being proposed to satisfy Minnesota's Solar Energy Standard (SES). Staff recommends that the NDPSC deny the requested ADP and also deny any replacement costs for the denied capacity." (Emphasis added.)

HOW DO YOU RESPOND?

A. Mr. Diller's summary touches on four important policy issues that I will address below. They are: (1) the timing and cost of generation additions to meet customer needs, (2) the relevant considerations and criteria (including least-cost planning principles) in selecting resources, (3) divergent state policies and the implications of those policies on a multi-state system, and (4) the implications and risks of direct-assigning generation to North Dakota.

## II. RESOURCE PLANNING OVERVIEW

Q. WHY ARE YOU PROVIDING AN OVERVIEW OF RESOURCE PLANNING IN YOUR TESTIMONY?

A. Mr. Diller's Direct Testimony raises important issues that are central to integrated resource planning and the Company's obligation to provide safe, reliable and adequate service to our customers under all reasonable circumstances. I think it is important for the Company to provide background and context on these issues to assist the Commission in considering the policy implications of Mr. Diller's proposed approach.

Q. PLEASE SUMMARIZE HOW THE COMPANY PLANS TO MEET ITS OBLIGATIONS.

A. Public utilities such as the Company have an obligation to serve all of the needs of all customers in their service areas. This obligation to serve requires that we provide for our customers' electric needs under all reasonable circumstances.

The obligation to serve leads to the utility planning its system to ensure sufficient generating capacity is available to meet customer requirements. In order to avoid the risk of falling short, we must plan for a future that has many unknowns. Realizing that new generation usually takes several years to develop – including planning and design, obtaining regulatory approvals, procuring transmission access and fuel supply, and of course the actual, physical construction – utilities generally must initiate the generation development process three to six years before the resource is needed. The future can look very different from what we expect today. The need to accommodate future uncertainties requires a utility to plan conservatively and ensure that adequate power supply exists even if unforeseen circumstances arise.

Q. WHAT DETERMINES WHETHER THE COMPANY NEEDS TO ADD GENERATION?

The Company has two major objectives when it considers whether to add new resources to the integrated system:

- Reliably serve customers during those hours when their needs are highest; and
- Minimize total system energy costs throughout the year, taking into account all relevant considerations.

To meet these twin goals, the Company considers both the need to meet our peak demand and our overall energy mix. There is more than one combination of resource types that can be employed to meet a given system's peak demand. And there is a variety of energy sources that can contribute to our mix.

Q. IS IT APPROPRIATE TO ONLY CONSIDER THE COMPANY'S CURRENT DEMAND FORECASTS WHEN DECIDING WHETHER TO ADD RESOURCES TO THE SYSTEM?

A. I agree that assessing and planning for the current forecast of peak demand is a critical consideration, but it is not the only criterion in our determination of what resources to add to the system. The Company must consider both the need to reliably serve our customers under all reasonable circumstances and to achieve a low-cost overall energy mix for our integrated system while meeting the policy requirements of all of the states we serve.

As a result, in planning resource additions, we take into account (1) peak demand, (2) reserve margin requirements, (3) contingencies such as higher-than-anticipated peak demand or forced (unplanned) outages, (4) energy mix (and overall energy costs), and (5) relevant policy considerations.

Q. WHY DOES THE COMPANY NOT PLAN NEW GENERATION TO PRECISELY MATCH FORECAST PEAK DEMAND?

A. The Company makes its resource investments within a long-term planning horizon – 40 years or more. It is not plausible to precisely match generating capacity with the exact customer demands in each year, keeping in mind that it is not acceptable to be short in any one year. We take a comprehensive approach to planning how we will serve all customers reliably throughout the planning horizon considering all circumstances.

Q. WHAT DO YOU MEAN BY A COMPREHENSIVE APPROACH TO PLANNING?

A. Several variables are considered. We consider (1) the size or amount of capacity to be added to the system including consideration of economies of scale, (2) the type of resource selected, such as natural gas or renewable resources, (3) the timing of the selection to ensure that we meet all of our obligations, and (4) whether there is firm delivery from the new generation site to the Company's customers.

For example, it is commonly known that the least expensive option for adding capacity is to build combustion turbines to serve as peaking plants. Yet, most utilities also plan for and build intermediate and baseload plants and add renewable energy to their systems – even at a much higher capital cost per MW than a peaking unit – to balance the energy needs of the customers they must serve. Utility planners understand that baseload plants and renewable energy resources are more expensive to build, but their energy production costs are relatively low.

Seeking to obtain an appropriate mix of baseload, intermediate, and peaking facilities helps to balance the costs of capacity and energy and obtain a diverse resource mix for the utility. A diverse resource mix, in turn, allows us to meet a wide range of needs from round-the-clock baseload energy to immediate peaking needs. A well-balanced generation portfolio provides a versatile and robust ability for a utility to respond to its customers' changing needs.

Q. WHAT ARE THE FACTORS THAT YOU CONSIDER WHEN DECIDING WHETHER AND WHEN TO INSTALL NEW GENERATION SUCH AS THE 187 MW SOLAR PORTFOLIO THAT IS THE SUBJECT OF THIS CASE?

A. First, new generation resources, including those that are the subject of this proceeding, require significant investment and time to build. We make generation resource decisions taking into account that we need to have enough time to deploy the generation resource to meet the identified customer need. This can be a challenge, since the development and construction cycle take up to five or more years during which time our demand forecasts could change dramatically (either up or down).

Second, economics generally favor building generation in fewer, but larger, capacity increments to capture economies of scale and to minimize duplicative infrastructure. This dynamic can result in choosing generation resources that exceed the immediate minimum forecast demand level by some amount to capture the benefits of the larger increment (*i.e.*, scale, efficiency, margins). Constructing larger increments of generation will also influence the timing of the next generation resource since, once built, a generation resource remains available to meet increasing demand, thereby deferring the addition of the next generation resource.

All of these factors tend to favor having a conservative amount of generation on the system going forward than what a simple analysis of the expected demand and the existing resources may suggest.

Q. DOES THE UTILITY PLAN ITS SYSTEM IN ISOLATION FROM OTHER UTILITIES?

A. In some ways yes, and in some ways, no.

On one end of the spectrum, a utility is ultimately responsible for ensuring that they will have adequate resource to meet its customers' needs. Therefore, utilities must do their own system planning, utilizing their own resource planning criteria, which is influenced by their obligations and regulatory oversight.

On the other end of the spectrum, planning paradigms have always taken into account the efficiencies achieved through interconnected operations with other interconnected utility systems. For example, when the Company was a member of the Mid-Continent Area Power Pool (MAPP), the ability to utilize other systems to ensure adequate capacity, and the MAPP requirements in this respect, were a key part of our resource planning considerations. Similarly, with the advent of MISO, the MISO reserve margin requirements are also a key consideration in our resource planning. Regional coordination enables all participating utility systems to meet reliability standards which lower reserve margins, than if each system operated on its own.

I stress, however, that the existence of other systems to support our resource adequacy does not fully compensate for the need to ensure we have sufficient capacity available on our system to meet our customers' needs. While regional constructs, such as MISO, can be helpful, I do not believe it is prudent to rely on MISO to ensure adequate resources are available should conditions change.

## III. RELIANCE ON MISO

Q. MR. DILLER TESTIFIES ON PAGE 3:8-14:

> "The structure of generation resource adequacy has changed under regional grid operators like the one NSP belongs to; Midcontinent Independent System Operator (MISO). One of the primary values of operating the electric system on a regional basis is to share generation assets to enable companies to carry a smaller reserve margin and improve reliability at the same time. It is no longer necessary or desirable for every utility to carry large amounts of excess generation as though they are still operated on a stand-alone basis."

HOW DO YOU RESPOND?

A. Mr. Diller is correct that regional operation such as under MISO may enable utility systems to carry smaller reserve margins than if they each operated on their own. He is also correct that MISO recently began operating a voluntary capacity auction that provides a small amount of short-term capacity to utilities for balancing their systems.

That said, I have some concerns with Mr. Diller's conclusion. Specifically, his position with respect to MISO does not fully consider all of the factors that must be taken into account when planning for future resource additions. These concerns relate mainly to MISO's resource adequacy requirements and the related planning reserve margin as well as the feasibility of relying on MISO's voluntary capacity auction. Fundamentally, we believe that participation in MISO does not remove our need to ensure that we have enough capacity resources for our own NSP System.

### A. MISO Resource Adequacy Requirements

Q. WHAT IS THE PURPOSE OF A PLANNING RESERVE MARGIN WITH RESPECT TO RESOURCE ADEQUACY?

A. The planning reserve margin represents additional generation capacity, over and above the utility's forecast of its customers' demand needs. Thus, the planning reserve margin is forward looking and based on the utility's forecasted demand. To illustrate, if a utility has 100 MW of forecasted demand and it requires 7 percent of reserve margin, it must have 107 MW of capacity.

The excess capacity required by the reserve margin is intended to accommodate operational fluctuations that occur throughout the year. In essence, the reserve margin is intended to ensure sufficient capacity is available to account for variations in the actual levels of demand as well as resource availability on peak days, as compared to the levels assumed in the forecast modeling. In this way, the reserve margin ensures that capacity is available to address the fundamental difference between forecasting and actual operations.

For example, our demand forecasts are weather normalized and so the reserve margin accounts for the actual variations in weather that we know will occur. As another example, our forecasts assume that our generating resources will be operating under normal conditions; the reserve margin provides a cushion for outages and derates that can affect the actual amount of generation available on any given day.

However, our demand forecasts are also keyed off of key economic indicators and other, non-operational, assumptions to determine our forecasted amount of customer demand. For example, we utilize econometric data such as housing starts and gross domestic product in building our demand forecasts. We also make assumptions about customer usage patterns and technological factors than can impact customer demand. Since the reserve margin does not take into account these non-operational factors and therefore is not designed to compensate for changes to these factors, should these non-operational assumptions prove to be incorrect, it is likely the reserve margin will not be sufficient to ensure that sufficient capacity is available to meet customer demand.

As described in my testimony in Case No. PU-15-095 (provided as Schedule 1), the Company has seen a fluctuation in its demand forecasts due to these non-operational metrics that argue for conservative resource planning notwithstanding the availability of a reserve margin.

Q. DOES THIS MEAN THAT YOU DO NOT AGREE THAT THE COMPANY SHOULD ONLY PLAN TO MEET ITS DEMAND FORECAST PLUS A RESERVE MARGIN?

A. Correct. The planning reserve margin has limits; it does not take into account that demand forecasts can shift dramatically in the four to six year period that it may take to develop or arrange for additional generation resources. Economic factors and historical usage are two of the more significant forecast variables, and the uncertainty in these variables since the 2008/2009 recession has been significant.

That is why we believe it is appropriate to take a conservative approach in resource planning by accounting for these variables that are not adequately captured by a planning reserve margin.

Q. DO YOU CONCUR WITH MR. DILLER THAT MISO'S PLANNING RESERVE MARGIN REQUIREMENTS ARE LIKELY TO DECLINE IN THE FUTURE?

A. It's difficult to say what the future holds for MISO's reserve margin requirements. MISO's reserve margin calculations are based on a series of assumptions. Under a certain set of assumptions, MISO forecasts that the current 7.1 percent planning reserve margin could decline to 6.6 percent in 2024. However, this result reflects assumptions that there will be significantly more generation added to the MISO system by 2024 and that these future resources will be more reliable than existing generation. However, given the uncertainty surrounding the utility industry and changes in generation technology, MISO concluded that a more likely outcome is that the reserve margin will stay relatively flat.

When we couple the changing industry with the potential of retiring a significant number of large baseload plants in the next several years, it is clear that the future need for new generation is very difficult to predict. It is my opinion that this uncertainty argues for a more conservative planning approach now.

**B. MISO Voluntary Capacity Auction**

Q. DO UTILITIES BUY AND SELL CAPACITY WITH EACH OTHER TO BALANCE THEIR NEEDS?

A. Yes. Historically, utilities have used bilateral agreements to buy and sell both short-term and long-term capacity and energy to each other. In addition to the traditional option of bilateral agreements, MISO has developed a voluntary short-term capacity auction as an option for utilities to use.

Q. DO YOU AGREE WITH MR. DILLER'S CONCLUSION THAT THE AVAILABILITY OF BALANCING CAPACITY THROUGH MISO PRECLUDES THE NEED FOR NSP TO PLAN FOR AND OBTAIN CAPACITY FOR ITS CUSTOMERS?

A. No. While MISO's efforts have been beneficial to customers, the short-term voluntary capacity auction administered by MISO is not an effective tool to replace traditional, single-system resource planning efforts. Utilities have typically accomplished the same outcome through bilateral transactions. Therefore, MISO's voluntary capacity auction merely provides another option for utilities to consider on a short-term basis only.

Q. IS IT PRUDENT FOR UTILITIES TO RELY ON MISO'S VOLUNTARY CAPACITY AUCTION TO BACKSTOP ANY RESOURCE DEFICIENCIES?

A. I do not believe so. The same factors that could contribute to a longer-term capacity deficit for a utility are likely to also lead to an absence of available capacity in the MISO voluntary capacity auction. Therefore, prudent resource planning would ensure that a utility's system has sufficient resources under all circumstances, notwithstanding the availability of a balancing mechanism such as the MISO voluntary capacity auction.

Q. PLEASE ELABORATE.

A. Fundamentally, it is only prudent to rely on MISO's voluntary capacity auction if we can be assured that sufficient capacity will be available in the MISO region when we need it. I do not believe that the current structure of MISO's voluntary capacity auction can provide such guarantees; let alone ensure that we can obtain the capacity at a reasonable price.

On the demand side, since a large portion of the capacity on a utility's system is driven by historical usage and economic factors, there is a high probability that when these key indicators change the customer demand on any one utility's system, they will also be changing the demand requirements of the other utilities within MISO. Thus, the capacity needed to support one utility's deficiency may likely be needed to support another utility's deficiency. Without a buffer of additional capacity above a utility's planning reserve margin, there is no guarantee that capacity will be available when it is needed.

Q. IS THE SAME THING TRUE ON THE SUPPLY SIDE?

A. Yes, the same is true on the supply side. With implementation of existing environmental regulations (*e.g.*, Mercury and Air Toxics Standards, Cross-State Air Pollution Rule) or potentially new regulations (*e.g.*, Clean Power Plan), there is a high likelihood that the economics of keeping existing power plants open will be adversely impacted, which could result in retirements. These retirements are likely to happen simultaneously across many utilities. The potential for significant future power plant retirements within a relatively short period of time could constrain available capacity when it is most needed.

Again, this uncertainty would suggest that MISO's voluntary capacity auction may have use as a backstop tool only, but not as a prudent resource to rely on to meet capacity needs. And relying on other utilities with excess generation to meet the Company's capacity needs could lead to unforeseen capacity deficiencies in the future.

## C. Other Considerations

Q. MR. DILLER POINTS OUT THAT MISO HAS A VERY LARGE FOOTPRINT,

INCLUDES SIGNIFICANT CAPACITY, AND PROVIDES ECONOMIES OF SCALE TO ITS MEMBERS. SHOULDN'T THIS HELP MITIGATE THE ISSUES YOU JUST DESCRIBED?

A. I generally agree with Mr. Diller that MISO provides these significant benefits to its members in the region. Through its roles as regional transmission provider and operating the regional energy market, MISO provides valuable coordination to the regional marketplace. Further, MISO's large footprint, and continual transmission planning efforts to reduce congestion on the MISO system, provide significant benefits to knit the MISO system together and provide outlet for location-based (*i.e.*, wind) generation for the entire MISO system.

However, the MISO footprint is split up into nine Local Resource Zones (LRZ). The transmission connections between each LRZ may not be sufficiently robust to allow for capacity to be shared amongst zones for resource adequacy purposes. To account for this, MISO has included a "Local Clearing Requirement" in its resource adequacy rules, which determines the amount of resources which must be located in a utility's LRZ so that it can meet its resource adequacy requirements.

Therefore, in reality, the Company must mainly rely (with a few exceptions) on the resources available in LRZ 1, which is where the NSP System is located. Having to rely on a single LRZ for capacity sharing significantly mitigates the economies of scale and geographic breadth of MISO for resource adequacy purposes. I note that the resource additions for which we are requesting an ADP have added value because they reside within LRZ 1.

I believe Mr. Diller's assessment overstates the usefulness of MISO's voluntary capacity market for resource adequacy purposes. In order for there to be sufficient capacity available in the MISO voluntary capacity auction that can be used for the NSP System, other utilities within LRZ 1 will need to have installed sufficient excess capacity to make up any shortfall the Company may have. If all utilities only planned to their reserve margin there would not be significant amounts of available capacity for the Company to use. Further, as the largest system in LRZ 1, the use of excess capacity provided by the fact that capacity additions are "lumpy" in nature could be insufficient for the Company to use.

To underscore the fact that reliance on MISO's voluntary capacity auction could result in a capacity shortfall, I note that MISO's capacity auction is held only about two months prior to the start of the applicable planning year. So, if the auction fails to supply needed capacity, there is essentially no time afterwards to correct the deficiency.

Q. MR. DILLER ACKNOWLEDGES ON PAGE 6:20-28 THAT THE COMPANY CAN INCUR SIGNIFICANT PENALTIES FOR FAILURE TO PLAN FOR ADEQUATE GENERATION TO COVER OUR PEAK DEMAND AND REQUIRED RESERVE MARGINS. HOW WOULD YOU RESPOND?

A. I agree that the potential for penalties is both real and substantial. However, I take issue with his apparent conclusion that it would be prudent to rely on purchasing short-term capacity to cover any potential shortfall that may arise.

Ultimately, MISO is not designed or intended to supplant the utility's traditional resource planning function nor the Commission's oversight and approval of generation resource selections. MISO's key responsibility is regional reliability. It implements its tariff on behalf of all stakeholders throughout the large MISO footprint. In fulfilling its functions, MISO's focus is properly on regional issues, rather than state- or utility-specific concerns.

Q. Are there other factors that the Commission should take into consideration?

A. Yes. As we described in great detail in our Resource Plan in Case No. PU-15-019, the utility industry and the NSP System are in a period of uncertainty and evolution. The utility industry as a whole will be impacted by the implementation of existing and new environmental regulations. Further, the NSP System may need to replace more than seventy-five percent of its energy resources by 2035. While it is likely that it will take years for these issues to be fully resolved, we must act in a very short timeframe to ensure we have adequate resources in place from 2016 to the early 2020s.

Q. Please describe the impact that MISO-wide capacity retirements that are currently contemplated by the Company and other MISO utilities will likely have on the prudence of making a resource addition at this time.

A. Our analyses indicate that the cost of generation development, especially natural gas-fired generation, may become more expensive as demand for new natural gas-fired generation increases due to the decommissioning of coal plants in the MISO footprint. And, as mentioned, these plant retirements are also expected to increase the costs of short-term capacity in MISO's voluntary capacity auction. Taking a conservative approach with diversified energy resources such as the solar resource additions that are the basis of this proceeding will position the Company well for the long term in light of these issues.

Q. ON PAGE 5:8-24, MR. DILLER DESCRIBES SOME POTENTIAL IMPACTS OF HAVING EXCESS GENERATION IN THE MISO REGION. HOW DO YOU RESPOND?

A. The Company appreciates Mr. Diller's discussion on this issue. However, I believe the situation is more complicated.

It is important to distinguish between recovery of production (energy) costs and recovery of capacity costs. Under MISO's current rules, we may only include our production costs when we offer generation into the market. Therefore, the energy markets only allow us to recover the marginal cost of producing the energy. In contrast, we recover our capacity costs by including our assets in rate base and recovering these investments through retail revenues, or, in the case of merchant generation, through bilateral contracts for the capacity.

When planning a utility system, one must plan for an optimal mix of energy and capacity. In certain circumstances, the overall least-cost method of providing energy and capacity to meet demand requirements is to install low-cost capacity generation (*e.g.*, combustion turbines) that is not expected to run often because of the high production costs to make this energy. The primary purpose of this low-cost capacity is to ensure that there are adequate resources available to meet peak demands; the energy value of that resource is of secondary importance. Therefore, this resource has value to the system by providing low-cost capacity since the system needs do not require the energy from this resource to meet demand needs except for a very few hours during the year.

It is rather complicated to identify the impact of a particular resource on energy prices in the market. The peaking resource I mention above would have little effect on energy pricing since it is designed to provide energy only during limited hours of the year. Whereas an intermediate resource would have more effect on the cost of energy since it is designed to produce more energy when there are needs above what can be met by regular baseload generation. This analysis becomes even more complicated when the impact of intermittent resources such as solar and wind are taken into account.

Q. PLEASE SUMMARIZE YOUR COMMENTS ON THIS MATTER.

A. The interplay of the types of resources on the system, their effect on energy pricing, and the carrying costs of capacity are what ultimately effects overall costs to our customers. In certain circumstances we may have the opportunity to add resources to our system that lower the overall costs of power to our customers by reducing energy prices by more than the incremental increase in capacity costs. This is the rationale behind most baseload power plants but also was the underlying economic justification for adding the Pleasant Valley and Border Winds projects to the NSP System. Although these resources added investments to rate base, these costs were offset by zero cost energy, thereby bringing down total system costs to our customers over their life.

## IV. PRUDENCE OF RESOURCE ADDITION

Q. MR. DILLER STATES ON PAGE 2:2-4 THAT INCREMENTAL NEW CAPACITY IS NOT NEEDED ON THE NSP SYSTEM AT THIS TIME. HOW DO YOU RESPOND?

A. I agree that our most recent demand forecast shows that we have sufficient capacity to serve our integrated system until 2024 without considering other issues. However, as I describe above, (1) we believe it is appropriate to plan conservatively to ensure we have resources available in case we experience an unexpected increase in demand, (2) obtaining the bare minimum of capacity to serve our peak-hour demand is not the only consideration that goes into deciding to add resources, and (3) we have other reasons to add solar capacity at this time, including the need to satisfy Minnesota's Solar Energy Standard. On balance, we conclude that the overall needs of our integrated system are better served by adding the 187 MW solar portfolio at this time.

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

A. Yes. Even beyond preparing to supply customer demand if growth increases faster than presently forecasted, adding solar generation at this time is an appropriate choice under the circumstances. Those circumstances include: (1) anticipated MISO-wide capacity retirements; (2) the currently-favorable interest rate and cost environment for solar generation; (3) an uncertain environmental regulatory environment and the likelihood that regulations will increasingly focus on carbon-free generation; and (4) our need to meet the Solar Energy Standard of the State of Minnesota.

Q. MR. DILLER SAYS THAT THE 187 MW SOLAR PORTFOLIO IS NOT A "LEAST-COST" RESOURCE. HOW DO YOU RESPOND?

A. Mr. Diller's observation is correct when looked at from one perspective, but it does not fully address all of the considerations we include in development and selection of resources. Let me explain:

I would agree that on a per-kWh basis, solar capacity and energy is not least-cost when compared to natural gas generation or even wind generation. However, when we make resource decisions, I do not believe the unit cost of a resource can be considered in isolation. For example, prudent resource planning would take into account policy drivers for a particular resource addition; market conditions which impact the cost of the generation in comparison to potential future costs; future system retirements; and resource diversity.

Mr. Diller does not explain what he is measuring against when he concludes the 187 MW solar portfolio is not least-cost. Given the Solar Energy Standard compliance obligation in Minnesota, I believe the most appropriate comparison is to consider the cost of this solar portfolio with the cost of similar solar projects that were available to us at the time we made this selection. As we describe in our filing, the three solar resources being considered in this case were selected because they were the least-cost solar resources that met the requirements of the competitive request for proposal (RFP) that we conducted.

Q. MR. DILLER SUGGESTS THAT LESS EXPENSIVE RESOURCE OPTIONS ARE AVAILABLE TO THE COMPANY. HOW DO YOU RESPOND?

A. As I mention above, I agree that the nominal cost of natural gas and wind generation is less than solar on a per kWh basis. But it is also important to consider other factors, such as the ones I described above.

I note that our resource plan contemplates significant additional solar generation during the planning horizon. Thus adding solar to the system now is appropriate in light of the overall circumstances. I also note that solar generation, while intermittent in nature, is generally producing energy during the peak periods of the day. This means that solar generation is available to offset high peak energy market pricing. This is in contrast to wind generation which is more likely to experience intermittent output primarily during non-peak periods.

## V. POLICY CONSIDERATIONS

### A. Multi-State Considerations

Q. YOU MENTIONED THAT ONE OF THE REASONS FOR SELECTING SOLAR RESOURCES AT THIS TIME IS THE NEED FOR THE COMPANY TO COMPLY WITH MINNESOTA'S SOLAR ENERGY STANDARD. IS NORTH DAKOTA REQUIRED TO FOLLOW MINNESOTA'S ENERGY POLICY AS IT PERTAINS TO SOLAR ENERGY?

A. No. North Dakota is free to implement its own state energy policies.

I agree with Mr. Diller's observation on page 8:5-10 of his testimony that North Dakota and Minnesota "should seek to mutually and beneficially coexist whenever possible so long as doing so is not detrimental to our own citizenry." However, there is more to consider in the determination of "detrimental" than simply whether the resource addresses a policy requirement in another state.

Q. PLEASE EXPLAIN.

A. The Company jointly plans for and operates an integrated system that serves more than 1.8 million retail electric customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. We have successfully planned for and managed the integrated NSP System to meet all of our customers' needs for almost 100 years. Because customers in all of our 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.

Q. CAN THE COMPANY ACCOMMODATE ALL OF THE ENERGY POLICIES OF ALL OF ITS STATES?

A. The simple fact is that Xcel Energy is *required* to comply with the energy policies of all of the states in which we provide service, and we are constrained by the regulatory processes prescribed by lawmakers and regulators in each state. We are finding it increasingly difficult to accommodate all of the various policies, as each state in which we provide electric service has different regulatory constructs and oversight regimes. However, we continue to believe that the benefits of our large integrated system outweigh the costs that may be imposed by any particular state.

Q. HOW DOES THE COMPANY ACCOMMODATE THE INTERESTS OF DIVERGENT STATE POLICIES IN MAKING RESOURCE CHOICES?

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

Q. WHAT SHOULD THE COMMISSION CONSIDER IN DECIDING WHETHER NSP'S RESOURCE DECISIONS ARE "DETRIMENTAL TO OUR OWN CITIZENRY" AS SUGGESTED BY MR. DILLER?

A. The Company believes it is important for the Commission to consider a broad range of factors including the interests of North Dakota customers as a whole, rather than focusing on any particular consideration. In other words, when viewing our resource choices with respect to our North Dakota customers, it is important to balance the cost impact of meeting certain non-North Dakota energy policy requirements with the economies of scale, and therefore lower costs, provided by the large demand from the other states in the NSP System. Even if the Company makes resource acquisitions in part to accommodate Minnesota's energy policies, it does not necessarily mean that our overall integrated resource mix is not in the best interest of all of our customers.

Q. PLEASE EXPLAIN.

A. What I mean by this is that the North Dakota citizenry experiences a variety of costs and benefits in being served by NSP's integrated five-state system. For example, our North Dakota customers are able to take advantage of their pro rata share of the Company's extensive nuclear, coal, natural gas and large hydro generation. These resources, which provide low-cost and efficient generation, would likely not be as available to our North Dakota customers if our North Dakota operation was a stand-alone system. This is because having the scope and scale of the other ninety-five percent of the NSP System allows the Company to obtain the critical mass to achieve significant economies of scale.

The Commission has historically approved the North Dakota share of the Company's resource choices, including even wind and biomass additions to the system. While many of those resources were added in furtherance of Minnesota energy policy, our North Dakota customers benefited overall from the integrated system while accepting the costs of those policy choices. In addition to the low-cost baseload facilities I mentioned earlier, the benefits included transmission system reliability improvements and fuel price volatility hedges from non-thermal generation additions.

In the end, the Company believes that there is a balance to be struck between (1) the benefits of a large, multi-state system, and (2) accommodating the requirements of a particular state's energy policy.

Q. SHOULD THE COMMISSION ALSO CONSIDER THE QUALITATIVE FACTORS OF THE COMPANY'S PROPOSED SOLAR RESOURCE ADDITIONS?

A. Yes. As we discuss at length in our recently filed resource plan, the utility industry and the NSP System are in a period of great change and significant uncertainty. We believe that our resource decisions during this time should be made with an eye to the future. The fuel price hedge and resource diversity value of our 187 MW solar portfolio are exactly the types of considerations that the Commission should take into account while evaluating our request. The Commission has been making these types of qualitative evaluations since at least 2008[1] and should continue to do so.

Q. PLEASE ELABORATE.

A. Our underlying purpose for making our proposed solar resource addition notwithstanding, there are material qualitative advantages of adding these resources to the NSP System at this time that argue for their prudence.

Solar is a developing resource and making utility scale additions to the NSP System will provide us with operational experience with this type of resource. Further, solar resources provide us with a hedge against other fuels, adding to our resource diversity. These resource additions will also help to position us should future carbon regulations in fact become mandatory. This is similar to the Company's experience with wind generation. While Minnesota policy was a driver in our initial additions of wind to the system, we are now seeing wind be an economic resource that can and does provide benefits to our customers, including comparatively low cost of energy that minimizes upside fuel price risk.

These qualitative factors are the same types of factors that the Commission has, in the past, used to recognize the prudence of renewable resource additions such as wind that were not least-cost (but were a reasonable cost for that resource type) and not utilized to meet an identified capacity deficit.[2]

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[1] *See* Case Nos. PU-06-481; PU-06-482.

[2] *See, e.g.* Case No. PU-08-907.

Given the uncertain future, we believe that a qualitative evaluation of our proposed resource addition is appropriate and will further demonstrate the prudence of our resource additions at this time at a system-wide net cost of only $14 million (compared to a total system cost of more than $1 billion) on a present value revenue requirements basis.

**B. Restack**

Q. WHAT OPTIONS DOES THE COMMISSION HAVE IF IT DOES NOT APPROVE THE COMPANY'S REQUEST?

A. I believe there are two basic options available to the Commission: (1) allow both the capacity and energy of the 187 MW solar portfolio to be re-priced through the North Dakota Restack process, or (2) direct-assign resources to be consistent with divergent state energy policies. Each of these choices carries important policy considerations.

Q. WHAT IS THE COMPANY'S RECOMMENDATION?

A. In this circumstance, we respectfully request that the capacity and energy of any resource for which the Commission does not grant an ADP be eligible to be included in the Restack process.

Q. PLEASE SUMMARIZE THE NORTH DAKOTA RESTACK PROCESS.

A. As the Commission is aware, development of a Restack Agreement with Commission Staff is guided by ten negotiating principles adopted by the Commission in the Settlement Agreement adopted in our last rate case. Key among these principles is that both the energy and capacity costs of any new resource addition (such as those proposed by the Company here) rejected by the Commission be re-priced using a suitable marginal cost proxy to essentially remove from North Dakota rates what the Commission has determined to be unacceptable policy premium costs of the resource. By addressing both the capacity and energy impacts of such resource additions, the Restack will acknowledge the "used and useful" nature of these resource additions to the NSP System while identifying and mitigating the cost impact for our North Dakota customers of energy policy decisions made in other states with which the Commission does not concur but which provide used and useful capacity and energy to the NSP System.

The Settlement Agreement's negotiating principles indicate that the appropriate proxy pricing would reflect the marginal cost of the next unit of capacity or energy available to be added to the system. We are currently negotiating the appropriate capacity and energy proxy pricing framework for this "marginal" cost with Commission Staff. The final Agreement will establish the "used and useful" pricing for any new resource additions subject to the Restack.

Q. WHY DO THE RESTACK NEGOTIATING PRINCIPLES INCLUDE A PROXY PRICING FOR CAPACITY EVEN IF THERE IS NO DEMONSTRATED CAPACITY DEFICIT JUSTIFYING THE ADDITION OF A PARTICULAR RESOURCE?

A. As I mentioned, the Restack concept is premised on maintaining the Company's ability to plan and operate the NSP System as an integrated system while at the same time addressing the impact of different state energy policies on our North Dakota customers. Using a proxy price for energy and capacity provides an objective standard (*i.e.* the cost of the next increment of energy or capacity to the system) to determine what type of "policy premium" exists for the resource addition.

Q. WHAT DO YOU MEAN BY THE TERM "POLICY PREMIUM?"

A. In this instance, Minnesota's energy policy calls for the Company to deploy additional resources that are of certain types and sizes. The Restack provides a mechanism to quantify the additional costs of both the capacity and energy from these resources due to other states' policy preferences. This "policy premium" provides a way to help ensure North Dakota's rates better reflect North Dakota energy policy judgments while allowing the Company to continue to make resource decisions for the integrated system.

Q. HOW DOES THE RESTACK CONCEPT MAINTAIN A BALANCE BETWEEN NORTH DAKOTA'S ENERGY POLICY JUDGMENTS AND THE COMPANY'S RESOURCE SELECTIONS?

A. By determining a proxy price for the capacity and energy, North Dakota customers are still contributing to used and useful resources on the integrated system and specifically for the energy they use and the capacity that is serving them. In this manner we are able to appropriately allocate the energy and capacity of all of the resources on the integrated NSP System to all of our customers, and thereby maintain the integrated nature of the NSP System.

Q. IF THIS 187 MW SOLAR PORTFOLIO IS NOT APPROVED BY THE COMMISSION, WHY WOULD IT BE APPROPRIATE TO INCLUDE IT IN THE RESTACK?

A. Yes. Should the Commission not deem our proposal prudent, we believe that including the 187 MW solar portfolio in the Restack allows us to continue to plan and operate the NSP System on an integrated basis while a long-term or permanent solution to the state divergent energy policy issue is being developed.

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

A. The Restack provides a short- to mid-term solution to the issue of accommodating divergent state policies by pricing and excluding from North Dakota rates the "policy premium" associated with those resources. It therefore reflects an opportunity to address policy differences while at the same time providing the Company with at least partial recovery for the capacity and energy that are actually being used to serve North Dakota customers.

Q. IF THE COMMISSION DOES NOT APPROVE THIS RESOURCE AND IT IS SUBSEQUENTLY INCLUDED IN THE RESTACK, WOULD NORTH DAKOTA CUSTOMERS BE PAYING FOR ENERGY AND CAPACITY THAT IS NOT NEEDED?

A. No. With respect to energy, this resource addition will likely displace the production of energy from other resources on the system. Because the system must always balance generation and load, all of our customers use the energy that is produced by these new resource additions when they are generating.[3] Therefore, the Restack is merely re-pricing energy that is being consumed by our North Dakota customers.

[3] 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 percent of the earnings on such sales.

Q. IF THE RESOURCE ADDITION SIMPLY DISPLACES ENERGY ALREADY ON THE SYSTEM, WOULDN'T THAT SUGGEST THE APPROPRIATE PROXY IS THE AVERAGE SYSTEM FUEL COST?

A. There is no "correct" answer to this question, only different policy outcomes that can be achieved through the use of proxy pricing. It is arguable that the true financial impact to the NSP System of the 187 MW solar portfolio would be the actual production costs of the NSP generation resources that are displaced by the 187 MW solar portfolio when the solar portfolio is generating. However, because MISO and not the Company dispatches all generation in MISO, the MISO Locational Marginal Pricing for the hours that the 187 MW solar portfolio is generating represents the cost to the Company of the energy it would have used to replace the generation of the solar portfolio.

In contrast, utilizing system average as a replacement proxy does not account for the marginal cost of the energy that the 187 MW solar portfolio displaces. Rather, a system average cost of fuel without the 187 MW solar portfolio represents a look at system costs without the 187 MW solar portfolio <u>or</u> some other resource that would have been generating in its stead.

Q. PLEASE ADDRESS WHETHER NORTH DAKOTA CUSTOMERS WOULD BE PAYING FOR *CAPACITY* THAT THEY DO NOT NEED.

A. Unlike energy, capacity is additive to the system and does not displace other capacity. Our resource planning efforts take into account the lumpy nature of capacity additions when planning for future additions to the system. By providing for capacity in the Restack Agreement, the negotiating principles in our rate case Settlement Agreement recognize the impact that capacity additions have on the need for and timing of the next increment of capacity for the system. When the Company adds the capacity represented by the 187 MW solar portfolio, the size, type, and timing of any future resource additions will be affected.

Q. WHY MUST CAPACITY BE INCLUDED IN THE RESTACK TO MAINTAIN THE INTEGRITY OF THE INTEGRATED SYSTEM?

A. 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 future capacity shortfalls for our North Dakota customers. 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. Doing so would be a departure from the integrated system approach.

**C. Implications of Direct Assignment**

Q. MR. DILLER RECOMMENDS THAT XCEL ENERGY DIRECT-ASSIGN GENERATION TO ITS NORTH DAKOTA CUSTOMERS AS A WAY TO ADDRESS DIVERGENT STATE ENERGY POLICIES. HOW DO YOU RESPOND?

A. Mr. Diller states his policy perspective on page 8:21-23 that "basic cost allocation and rate design principles require that costs be assigned to the cost causers whether allocating costs between states or to various customer classes." I agree with Mr. Diller's perspective and that cost causation is an important consideration. But cost causation isn't the only relevant criteria to inform the Commission's consideration.

I think it is important that the Commission also recognize that our integrated five-state system allows us to plan and implement it on a consolidated basis in order to meet all of our customers' needs as well as complying with all of the policies in all of our states. Overall this has proved to be a cost-effective way for us to serve our North Dakota customers as well as the customers in the other four states. While it may be true that some of the costs we incur are designed to address specific policies in Minnesota, we do not believe this nullifies the overall value of the integrated system to our customers in North Dakota.

Q. WHAT ARE SOME OF THE IMPLICATIONS IF THE COMMISSION DECIDES TO ADOPT A POLICY OF DIRECT-ASSIGNING GENERATION CONSISTENT WITH NORTH DAKOTA'S ENERGY POLICY?

A. If one state requires that we direct-assign generation to avoid the impact of another state's energy policy, we will no longer be able to manage the NSP System as an integrated whole since some capacity component of our resource additions will not be available to the system. This will require us to plan for and manage our North Dakota customers on a separate basis than the remainder of the NSP System.

Q. WOULD THE OUTCOME BE THE SAME IF THE COMMISSION DENIED AN ADP FOR THE COMPANY'S REQUESTED RESOURCE ADDITION AND DID NOT ALLOW THE ENERGY OR CAPACITY COSTS TO BE RE-PRICED THROUGH THE RESTACK PROCESS?

A. Yes. Rejecting the capacity from the Restack, as Mr. Diller recommends, would eliminate this capacity from consideration for serving our North Dakota customers. This will make it impossible to continue to fully integrate our North Dakota customers into the NSP System on a going-forward basis.

Q. PLEASE EXPLAIN.

A. Eliminating the capacity component from recovery in the Restack would mean that North Dakota could not take advantage of that capacity since it would be making no contribution to the cost of that generation. This would require the Company to plan separately for how to meet North Dakota's capacity needs. Ultimately, this would result in a separate analysis of when new generation is needed to serve our North Dakota customers and would require that we deploy generation specifically dedicated to North Dakota.

Q. DO YOU HAVE GENERAL CONCERNS OVER DIRECT-ASSIGNING CAPACITY AWAY FROM NORTH DAKOTA?

A. Yes. In order to maintain the integrated system, we must be able to allocate all of our generation across all of our states. If a state chooses to reject a particular resource, then that generation must be allocated away from that state to avoid the state using capacity it is not paying for. Ultimately, direct-assignment would require the Company to separate its utility operations by jurisdiction to ensure that all capacity being dedicated to each jurisdiction is properly accounted for.

Q. ARE THERE OTHER PROBLEMS WITH THE CONCEPT OF DIRECT-ASSIGNMENT?

A. Yes. Direct-assigning generation away from North Dakota raises the risk that North Dakota could find itself in a capacity deficit position (on an individual basis) even if NSP's overall portfolio would have enough generation to serve North Dakota but for the fact that some of that generation was direct-assigned away.

Q. WHAT WOULD THE COMPANY HAVE TO DO IF IT FORECASTED A CAPACITY DEFICIENCY FOR ITS NORTH DAKOTA OPERATION AND WAS UNABLE TO PLAN FOR THE NSP SYSTEM ON AN INTEGRATED BASIS?

A. We would have to procure additional resources specifically dedicated to North Dakota to make up for the deficit created by direct-assigning existing capacity. We could do this by purchasing capacity from another utility (if it was available) or we could try to obtain that capacity using the MISO voluntary capacity auction. However, as described above, procuring capacity through those market mechanisms is risky and not assured. We could also seek to obtain capacity through either short-term or long-term bilateral transactions.

Another alternative is that the Company would need to build additional capacity for our North Dakota customers to meet that deficit. In this scenario, we would consider the size, type and timing of construction to address this deficit and would expect that it would be a smaller unit than would be possible if we were planning for the NSP System on an integrated basis.

I note that because this would be a resource dedicated to meeting only our North Dakota customers' capacity needs, we would anticipate direct-assigning these costs to our North Dakota jurisdiction.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission decline to direct-assign generation on the Company's system and that the Commission allow us to reflect the used and useful portion of the capacity we propose to add to our system. In this instance, we recommend that the Commission grant the requested ADP for the 187 MW solar portfolio or, in the alternative, allow both the energy and capacity from this purchase to be re-priced through the North Dakota Restack process.

## VI. CHANGES TO PPAS

Q. HAVE THE PPAS CHANGED SINCE THE TIME THEY WERE FILED WITH THE COMMISSION WITH THE COMPANY'S APPLICATION?

A. Yes, minor edits were made to the PPAs. The only substantive edit was to conform the regulatory approval language with the PPA we entered into for the Geronimo Solar Project that is the subject of Case No. PU-15-095. These conforming changes were made by letter agreement between the Company and PPA developers and are attached as Schedule 2[4].

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

[4] *See also* March 24, 2015 ORDER APPROVING SOLAR PORTFOLIO in MPUC Docket No. E002/M-14-162.

# 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 187 MW PORTFOLIO OF UTILITY SCALE SOLAR RESOURCES

**Case No. PU-14-810**

**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, and in the above captioned matter, that he has read the testimony and schedules submitted under his name, that he testimony and schedules 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 8th day of April, 2015.

Notary Public
My Commission Expires: 1-31-2020

CYNTHIA D. HARRINGTON
Notary Public, State of Minnesota
My Commission Expires
January 31, 2020

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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 Aurora Distributed Solar, LLC for up to 100 MW of Solar Generation

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

**Resource Planning Policy Testimony**

February 13, 2015

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## Schedules

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## I. INTRODUCTION AND QUALIFICATIONS

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 Geronimo Solar power purchase agreement (PPA), which is included as Trade Secret

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

- The Company's utilization of its Fall 2011 Forecast to establish this need that is being met by the Geronimo Solar PPA;
- The impacts that demand forecast variability have on the nature and timing of our resource acquisition decisions; and
- The impacts o four proposed resource acquisitions on the "Restack" concept established in the Settlement Agreement in Case No. PU-12-813.

## II. RESOURCE NEED

Q. IS THE COMPANY PROPOSING ITS RESOURCE ADDITION TO MEET AN IDENTIFIED NEED?

A. Yes. The Company has identified a need of between 150-500 MW of additional capacity in the 2017-2019 time frame. Company Witness Mr. Paul B. Johnson discusses this need further in his Direct Testimony.

Q. HOW DID THE COMPANY IDENTIFY THIS NEED?

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

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

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

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

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

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

Q. WHAT NEED DID THE FALL 2011 FORECAST IDENTIFY?

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

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

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

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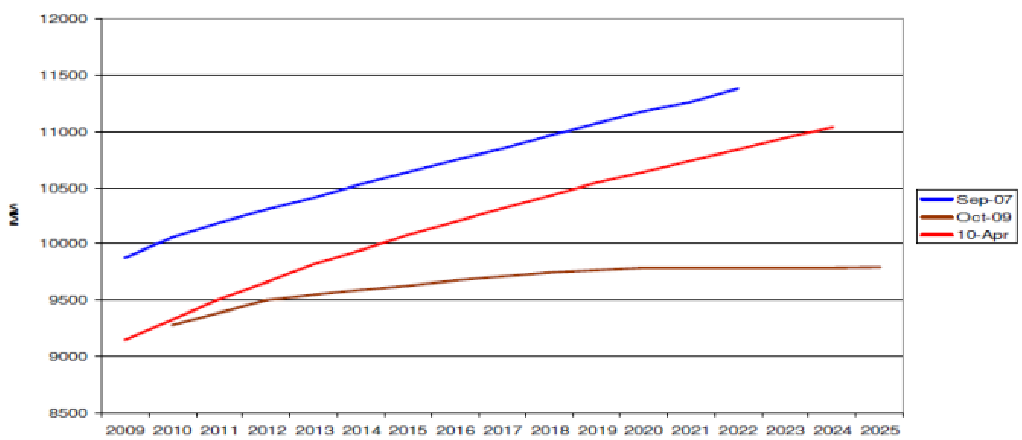
forecasts during this time period. As a result, if actual circumstances do not match the assumptions used to develop the forecast, then actual results will be different than the forecasted results.

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

**Figure 1.3**
**Demand Forecast Over Time**




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

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

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

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

Q. WHAT DID THESE FORECASTS UPDATES INDICATE?

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

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

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

While the range of these more recent forecasts falls within an error band, or probability range, of only two to three percent, these changes result in varying estimates of peak demand by approximately 250 MW within the 2016-2020 timeframe.

## III. IMPLICATIONS OF NEED ASSESSMENT

Q. WHAT ARE THE IMPLICATIONS OF THE VARIABILITY OF DEMAND FORECASTS OVER TIME?

A. 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. And, while our most recent 2105 Resource Plan forecast suggests weakening demand, this forecast also demonstrates that our capacity position in 2019 and 2020 is very near a deficit. In other words, our forecast updates have demonstrated a slackening of demand that could argue to postpone making capacity additions. However, we believe that a conservative approach to meeting our needs is appropriate at this time.

Q. PLEASE ELABORATE.

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

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

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

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

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

A. Our recommended 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

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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 the short-term capacity markets and the price uncertainty inherent with such markets. Company Witness Johnson discusses further in his Direct Testimony how the Geronimo Solar PPA in combination with the Calpine Project PPA and Black Dog Unit 6 appropriately address our customer's need under all reasonable circumstances, specifically including the softer need forecast in our 2015 Resource Plan.

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

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

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

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

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

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

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

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

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

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

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

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

## IV. MPUC ASSESSMENT OF NEED

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

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

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

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

Q. DID THE MPUC AGREE WITH THIS FORECAST UPDATE?

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

Q. DID THE COMPANY PROVIDE ANY ADDITIONAL UPDATES?

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

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previously assumed. We suggested that the 2014 forecast update would support a potential delay of two years or more in adding any new capacity to our system.

Q. DID THE MPUC AGREE WITH THE COMPANY ON THIS POINT?

A. No. In its February 5, 2015 Order selecting the Geronimo Solar PPA and Calpine Project PPA for execution, the MPUC found that it was more appropriate to rely upon the forecasts that were used in our 2010 Resource Plan, which supported a finding of 150-500 MW of capacity need in the 2017-2019 timeframe. The MPUC concluded that a conservative approach was the most appropriate outcome. In order to ensure that adequate generating capacity is installed in a timely fashion, it is necessary to adopt an analysis and finalize the inputs in order to provide certainty and finality to the decision-making process. As the MPUC stated in that Order:

> Need assessments are necessarily approximate and even the most analytic utilities must plan for a range of outcomes. In this docket, the Department has evaluated the consequences of selecting various combinations of generators under multiple scenarios – including a scenario of lower-than-expected demand. In short, Xcel's latest demand forecast, though new, was still within the range of contingencies contemplated and evaluated by the Department.

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> Finally, the [Minnesota] Commission's goal is not to forecast the precise level of need – a task rife with the potential for error – but to identify the resource mix that will best manage forecasting error . . .. Based on the state of the record regarding Xcel's latest need assessment, the Commission will decline to alter its finding of need on this basis.

Q. DOES XCEL ENERGY AGREE WITH THE MPUC'S DECISION TO CHOOSE NEW CAPACITY DESPITE THE MOST RECENT FORECASTS SHOWING A REDUCED NEED?

A. The Company accepts that there are a number of ways to review capacity needs and that any single forecast is not determinative. While we provided information that suggests deferring the acquisition of additional capacity could be appropriate, we are comfortable that acquiring capacity at this time is consistent with the long-term needs of our customers.

## V. COMPANY ADP REQUEST

Q. WHAT IS THE COMPANY'S REQUEST IN THIS PROCEEDING?

A. The Company is requesting that the Commission grant an ADP for the Geronimo Solar PPA. As described in our application and supporting testimony, this PPA, as well as the Calpine Project PPA, are prudent resources to meet our capacity needs in the 2017-2020 time frame.

Q. COULD THE COMMISSION DENY THE COMPANY'S REQUEST?

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

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

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

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

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

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

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

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

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

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

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

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

Capacity, on the other hand, is additive to the system and does not displace other capacity. Our resource planning efforts take into account the lumpy nature of capacity additions when planning for the next capacity additions to the system. By providing for capacity in the Restack Agreement, the negotiating principles in our rate case Settlement Agreement recognize the impact that capacity additions have on the need for and timing of the next 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 Geronimo Solar PPA and Calpine Project 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

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

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

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

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

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

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

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Xcel Energy

1800 Larimer Street, Suite 1000
Denver, CO 80202

April 2, 2015

Mr. Tim Oliver
Executive Director
NextEra Energy Resources, LLC
700 University Boulevard
Juno Beach, Florida 33408

Mr. Mitch Ross
Vice President and General Counsel
NextEra Energy Resources, LLC
700 University Boulevard
Juno Beach, Florida 33408

Re: Exhibit A, Definitions, Solar Energy Purchase Agreement

Dear Mr. Oliver,

Northern States Power Company ("Company") and Marshall Solar, LLC, ("Seller" and jointly with the Company, the "Parties") have entered into a Solar Energy Purchase Agreement, (the 'PPA") dated as of March 3, 2015. Section 20.17 of the PPA provides the right to change an Exhibit with the mutual consent of both Parties.

Accordingly, Company and Seller agree to change Exhibit A, Definitions, "State Regulatory Approval" so that the definition now reads: "State Regulatory Approval" occurs after a final written order is received from one State Regulatory Agency, or if needed, both State Regulatory Agencies, and means final written orders that (i) are not subject to application for rehearing, reargument or reconsideration and (ii) singly or in the aggregate make affirmative determination that Company's execution of this PPA is prudent and/or in the public interest, and that all costs incurred under this PPA as currently allocated by ratemaking mechanisms to Company's Minnesota and North Dakota jurisdictions are recoverable, in the aggregate, from the Company's Minnesota and/or North Dakota retail customers. The preceding is subject only to ongoing prudency review of Company's performance and administration of this PPA.

Seller and Company acknowledge and agree that this letter does not constitute an amendment to the PPA, which shall remain in full force and effect.

Please sign below in acknowledgment and agreement of the foregoing on both signed copies enclosed and return one fully executed copy to Company.

Sincerely,

**NORTHERN STATES POWER COMPANY**

By:________________________
Name: Thomas A. Imbler
Title: Vice President, Commercial Operations
Xcel Energy Services Inc. as agent for
Northern States Power Company

Acknowledged and agreed to this __14__ day of April, 2015.

**Marshall Solar, LLC**

________________________

Michael O'Sullivan
Vice President

Xcel Energy

1800 Larimer Street, Suite 1000
Denver, CO 80202

April 6, 2015

Jay T. Sonnenberg
General Counsel
MN Solar I LLC
c/o juwi solar Inc.
1710 29th Street, Suite 1068
Boulder, CO 80301

Re: Exhibit A, Definitions, Solar Energy Purchase Agreement

Dear Mr. Sonnenberg,

Northern States Power Company ("Company") and MN Solar I LLC ("Seller" and jointly with the Company, the "Parties") have entered into a Solar Energy Purchase Agreement, (the 'PPA") dated as of February 19, 2015. Section 20.17 of the PPA provides the right to change an Exhibit with the mutual consent of both Parties.

Accordingly, Company and Seller agree to change Exhibit A, Definitions, "State Regulatory Approval" so that the definition now reads: "State Regulatory Approval" means final written orders from one State Regulatory Agency, or if needed, both State Regulatory Agencies that (i) are not subject to application for rehearing, reargument or reconsideration, and (ii) singly or in the aggregate make an affirmative determination that Company's execution of this PPA is prudent and/or in the public interest, and that all costs incurred under this PPA as currently allocated by ratemaking mechanisms to Company's Minnesota and North Dakota jurisdictions are recoverable, in the aggregate, from the Company's Minnesota and/or North Dakota retail customers. The preceding is subject only to ongoing prudency review of Company's performance and administration of this PPA.

Seller and Company acknowledge and agree that this letter does not constitute an amendment to the PPA, which shall remain in full force and effect.

Please sign below in acknowledgment and agreement of the foregoing on both signed copies enclosed and return one fully executed copy to Company.

Sincerely,

**NORTHERN STATES POWER COMPANY**

By:______________________________
Name: Thomas A. Imbler
Title: Vice President, Commercial Operations
Xcel Energy Services Inc. as agent for
Northern States Power Company

Acknowledged and agreed to this 6th day of April, 2015.

**MN Solar I LLC**

______________________________
Jay Sonnenberg
Secretary

Xcel Energy[SM]

1800 Larimer Street, Suite 1000
Denver, CO 80202

April 13, 2015

Mr. Eric Blank
Manager
North Star Solar PV LLC
3 Radnor Corporate Center, Suite 300
100 Matsonford Road
Radnor, PA 19087

Ms. Molly Arbes
Treasurer
Community Energy, Inc.
3 Radnor Corporate Center, Suite 300
100 Matsonford Road
Radnor, PA 19087

Re: Exhibit A, Definitions, Solar Energy Purchase Agreement

Dear Mr. Blank:

Northern States Power Company ("Company") and North Star Solar PV LLC ("Seller" and jointly with the Company, the "Parties") have entered into a Solar Energy Purchase Agreement, (the 'PPA") dated as of March 6, 2015. Section 20.17 of the PPA provides the right to change an Exhibit with the mutual consent of both Parties.

Accordingly, Company and Seller agree to change <u>Exhibit A</u>, Definitions, "<u>State Regulatory Approval</u>" so that definition now reads "<u>State Regulatory Approval</u> occurs after a final written order is received from one State Regulatory Agency, or if needed, both State Regulatory Agencies, and means final written orders that: (i) are not subject to application for rehearing, reargument or reconsideration, (ii) singly or in the aggregate make an affirmative determination that Company's execution of this PPA is prudent and/or in the public interest and (iii) that all costs incurred under this PPA, as currently allocated by ratemaking mechanisms to Company's Minnesota and North Dakota jurisdictions, are recoverable, in the aggregate, from the Company's Minnesota and/or North Dakota retail customers. The preceding is subject only to ongoing prudency review of Company's performance and administration of this PPA."

Seller and Company acknowledge and agree that except as expressly set forth in this letter, nothing herein shall (i) affect the rights or obligations of the Parties as contained in the PPA or (ii) amend the terms of the PPA which shall remain in full force and effect.

Please sign below in acknowledgment and agreement of the foregoing on both signed copies enclosed and return one fully executed copy to Company.

Sincerely,

**NORTHERN STATES POWER COMPANY**

By:______________________________
Name: Thomas A. Imbler
Title: Vice President, Commercial Operations
Xcel Energy Services Inc., as agent for
Northern States Power Company

Acknowledged and agreed to this __14__ day of April, 2015.

**North Star Solar PV LLC**

______________________________

Name: Eric Blank
Title: Executive Vice President