Direct Testimony and Schedules
Philip Joseph "P.J." Martin

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA**

IN THE MATTER OF COMMISSION STAFF'S REQUEST TO INVESTIGATE NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY'S PROPOSED FUEL CLAUSE RIDER

DOCKET NO. EL16-037
EXHIBIT____ (PJM-1)

RESOURCE PLANNING

June 30, 2017

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Philip Joseph "P.J." Martin. I am the Director, Resource Planning, for Northern States Power Company-Minnesota (NSPM or Xcel Energy or the Company).

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since August of 2015 in the areas of Strategic Asset Planning and Resource Planning. In my first role at Xcel Energy in the Strategic Asset Planning group, I focused primarily on business planning for the four operating companies at Xcel Energy. I assumed my current role as Director, Resource Planning in October of 2016.

Prior to joining Xcel Energy, I worked as a Portfolio Director and Energy Trader at ACES Power Marketing. In these roles, I engaged in trading and wholesale portfolio management activities on behalf of electric cooperatives, municipal utilities, IPPs, banks, and other customers. I also supported long-term planning and risk management efforts for these customers in the Midcontinent Independent System Operator, Inc., PJM Interconnection, LLC (PJM), Southeast Electric Reliability Council (SERC), and other markets across the United States. My statement of qualifications is provided as Exhibit ___(PJM-1), Schedule 1.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. In my current role, I am responsible for the direction of electric resource planning for the five-state integrated Northern States Power Company system (NSP System), which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. This includes assisting the Company in making reasonable and prudent acquisition decisions for electric generation resources. Among other things, I oversee our resource planning efforts using Strategist to conduct economic evaluations of potential resource additions, and oversee bid processes for new resource acquisitions.

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

A. I describe the NSP System and the benefits it provides to customers. I also provide economic analyses and context supporting the Aurora Solar, North Star Solar, and Marshall Solar resources. I also provide context for the various processes that were used to select these resources.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I first discuss the NSP System. I then discuss the selection of the Aurora Solar Project and provide the economic analysis supporting that selection. Last, I discuss the Company's selection of its 187 MW Solar Portfolio, of which North Star Solar and Marshall Solar are a part, the economic analysis supporting its selection, and the status of the projects.

II. THE INTEGRATED NSP SYSTEM

Q. PLEASE DESCRIBE THE NSP SYSTEM.

A. The Company is a wholly-owned operating subsidiary of Xcel Energy Inc. that owns and operates, in conjunction with its affiliate Northern States Power Company – Wisconsin (NSPW), the integrated system of generation and transmission assets that serves approximately 1.6 million electric customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin (the NSP System). The NSP System developed over many years: as the electric power needs of its customers grew and evolved, the Company undertook various large-scale investments to serve them.

Q. WHY DO YOU REFER TO THE NSP SYSTEM AS "INTEGRATED"?

A. Each resource in the NSP System - whether generation or transmission - was developed in consideration of the whole, balancing the need for system reliability, fuel and load diversity and hedges against supply and cost volatility.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF NSP'S INTEGRATED SYSTEM.

A. The history of NSP's generation and transmission assets is a long and detailed story, spanning decades. I will provide a very condensed version here.

From the 1940s to the 1960s, the Company utilized the central station development common at the time and mainly constructed coal-fired generators around the Twin Cities, its main load center, including the Black Dog plant in Burnsville, Riverside plant in Minneapolis, High Bridge plant in St. Paul, and the Allen S. King plant in Bayport. These plants were tied together with high-voltage transmission lines.

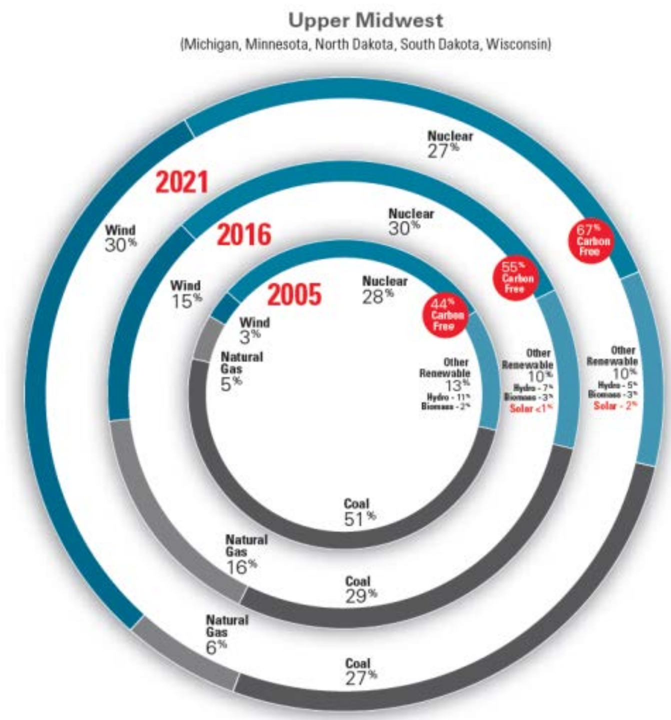
By the late 1950s, load was increasing very rapidly. In response, in the 1960s the Company built the 345 kV transmission loop around the Twin Cities and built 345 kV transmission lines between the Twin Cities and St. Louis, Chicago, and Omaha, as well as a 500 kV transmission line from Winnipeg to the Twin Cities. These lines provided greater reliability, enhanced economies of scale, and enhanced diversity of supply because they allowed power to be imported from other regions, such as the importation of hydroelectric power from Manitoba.

These transmission lines were also important in the development of large central station generators that were built in the 1960s and 1970s, such as the King plant, the Monticello and Prairie Island nuclear plants, and the Sherburne County plants (Sherco 1 and 2). In the 1980s the Company added the Sherco 3 plant. The Company also added a significant amount of natural gas generation to its system in the 1970s, 1980s, and 1990s such as Angus Anson 2 and 3, Inver Hills 1-6, and Wheaton 1-6. Since the mid-1990s, the Company has added approximately 2,500 MW of renewable energy generation.

Q. PLEASE DESCRIBE THE GENERATION SOURCES COMPRISING THE INTEGRATED NSP SYSTEM AS IT EXISTS NOW.

A. The NSP System includes many sources of electricity generation. Currently, our system energy mix includes approximately 29 percent coal, 30 percent nuclear, 15 percent wind, 16 percent natural gas, 7 percent hydro, 3 percent biomass, and less than 1 percent solar.

Figure 1



[Source: 2016 Corporate Responsibility Report]

Q. ARE THERE ADVANTAGES TO THE INTEGRATED GENERATION PORTFOLIO THAT RESULTED FROM THIS HISTORICAL PROCESS?

A. Yes. One advantage is economies of scale. The development of large generation facilities generally provided lower per-unit costs and drove efficiencies. Because of the large size of the integrated system, the Company has the scale to respond to capacity needs by building additional, large, generation facilities.

A second advantage is reliability - if there is a problem at one generation location, other locations can fill the need. These advantages are not possible without an integrated system that includes both a variety of generation assets and sufficient transmission infrastructure.

A third advantage is the ability to utilize diverse fuel supplies. The price of fuel used in producing energy, such as coal and natural gas, is subject to significant fluctuations over time, depending on macroeconomic forces. Because of the integrated nature of the NSP System, if the price of one type of fuel increases relative to another, more power can be drawn from other sources. This pooling of resources hedges the risk of being over-dependent on a single or very limited number of fuel sources. For example, if there were to be a significant spike in the price of natural gas, the diversity of the NSP portfolio provides access to coal and other non-gas-fired resources that would provide a more economical solution to serve load. We are seeing this today with historically low gas prices pushing down our coal generation.

Q. WHAT ROLE DOES THE COMPANY'S SOUTH DAKOTA SERVICE TERRITORY PLAY IN THE NSP SYSTEM?

A. The Company's South Dakota service territory is a contiguous and integral part of the NSP System. In light of this, our South Dakota jurisdiction enjoys strong transmission ties to our generation facilities and hosts the key peaking facility, the Angus Anson generating station. In addition to providing important peaking capacity and energy, Angus Anson is also available to provide reliability support in the Sioux Falls, South Dakota area. The completion of a number of new Midcontinent Independent System

Operator (MISO) Multi-Value Projects including the Brookings to Southeast Twin Cities 345 kV transmission line have enhanced interconnectivity between South Dakota load centers and the rest of the MISO system and further enhanced reliability and efficient resource dispatch.

Q. HAVE HISTORIC EVENTS IMPACTED THE VALUE OF THE NSP SYSTEM?

A. The 1992 Energy Policy Act called for the creation of competitive wholesale electric markets. In 1996, under the auspices of that Act, the Federal Energy Regulatory Commission (FERC) issued Order Nos. 888 and 889. These Orders required utilities to separate the generation function from the transmission function and set the stage for regional transmission organizations. A few years later, MISO was created, and by 2005 MISO began centralized dispatch of all generation across its upper-Midwest footprint.

Q. DOES THE COMPANY STILL PLAN FOR THE NSP SYSTEM IN AN INTEGRATED MANNER?

A. Yes. The investments necessary for safe, reliable electric service are capital-intensive. Generally, integrated system planning is the best way to achieve economies of scale. In addition, integrated system planning allows the states we serve to share in the costs of resources, and provides diversity and hedge benefits.

Q. ARE THE BENEFITS OF INTEGRATED SYSTEM PLANNING STILL IMPORTANT?

A. Yes. On behalf of all customers, we have taken advantage of the geographic, supply, and resource diversity that the five-state NSP System provides, with all states sharing in the costs and benefits of this system. While maintaining an integrated system at times requires necessary compromises between the various customer groups and jurisdictions we serve, the size and scope of the integrated NSP System continues, we believe, to benefit all of our customers. These advantages remain true and important even in the market-oriented competitive landscape that has developed over the last 20 years.

Q. HOW DOES THE COMPANY PLAN FOR RESOURCES GIVEN THE INTEGRATED NATURE OF ITS SYSTEM?

A. We plan our resource investments based on a long-term planning horizon. We do not make resource selection decisions based only on meeting peak load; but rather, we consider how to meet all loads throughout the planning horizon, and across our entire service area, on a reliable and cost-effective basis.

Q. HOW DOES INTEGRATION INFLUENCE THE COMPANY'S RESOURCE PLANNING?

A. Planning for, and managing, the integrated NSP System is highly complex and requires us to balance the needs and priorities of all of the jurisdictions we serve. We strive to consider the goals of each jurisdiction when planning. We also are obligated to meet the regulatory requirements applicable in each jurisdiction, which as a practical matter means that whichever state has the most stringent requirements sets the bar for our compliance.

Given that, we develop a single resource plan for our entire system that respects the jurisdictional constraints, yet allows us to capture the benefits derived from pooling loads and resources. We are required to file a comprehensive resource plan in some of the jurisdictions where we serve to demonstrate that we are pursuing prudent investments on behalf of customers. Our most recent Upper Midwest Resource Plan (often referred to as the Integrated Resource Plan or IRP) provides a very detailed description of the considerations that we balance as we undertake resource planning. The Company filed its IRP in South Dakota on January 29, 2016.

III. AURORA SOLAR

A. Identification of Resource Needs

Q. WAS THERE A RESOURCE NEED FOR WHICH THE AURORA SOLAR PROJECT WAS SELECTED TO MEET?

A. Yes. The Company's 2011-2025 Integrated Resource Plan (2010 IRP) (Minnesota Docket No. E002/RP-10-825) identified a need of 150 MW by 2017, increasing up to 500 MW by 2019.

Q. HOW DID THE COMPANY PROPOSE TO MEET THIS NEED?

A. The Company proposed meeting the need identified in the 2010 IRP with Company-owned self-build combustion turbine projects (Black Dog Unit 6 and Red River Valley Units 1 and 2).

Q. DID THE COMPANY UPDATE ITS FORECASTS AFTER THE 2010 IRP?

A. Yes. Regularly updating our load forecasts is a normal part of our resource planning efforts. To help ensure that a need still existed for our proposed gas combustion turbines, we updated our forecast in Fall of 2011.

Q. WHAT DID THESE FORECAST UPDATES INDICATE?

A. The Fall 2011 Forecast identified capacity need of approximately 150 MW beginning in 2017 that grew to approximately 500 MW in 2019/2020, and suggested a capacity need growing to 920 MW by 2024. This confirmed that moving ahead with our proposal was appropriate.

As Company Witness Mr. Aakash Chandarana explains in his Direct Testimony, a competitive acquisition process (CAP) was initiated in Minnesota because the Company proposed self-build projects to meet the identified capacity need.

B. The Competitive Acquisition Process Proceeding

Q. WHAT PROJECTS WERE PROPOSED IN THE CAP PROCEEDING?

A. In addition to the Company's proposals, there were four proposals to add natural gas generation to the Xcel Energy system: one from the Company, two from Invenergy Thermal Development LLC, and one from Calpine Corporation. Great River Energy proposed a short-term capacity credit purchase, while Geronimo Energy submitted a solar proposal. I provide details on the cost and performance of each proposal, by year, in Exhibit____(PJM-1), Schedule 2.

1. Xcel Energy's Natural Gas Peaking Proposal

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL IN THE CAP PROCEEDING.

A. The Company proposed three new natural gas peaking plants consisting of one unit at the existing Black Dog site in Burnsville, Minnesota and two units at a new site near Hankinson, North Dakota (Red River Valley Units 1 and 2). Each of the natural gas combustion turbines (CTs) has an expected capacity of 208 MW, for a total of 624 MW.

Q. WHAT WAS THE COMPANY'S PROPOSAL FOR BLACK DOG UNIT 6?

A. The Company proposed that the 208 MW Black Dog Unit 6 addition be placed in service in either 2017, 2018, or 2019.

Q. WHAT WAS THE COMPANY'S PROPOSAL FOR RED RIVER VALLEY?

A. The Red River Valley Units, each at 208 MW, were proposed to be in-service in 2018 and 2019, respectively.

2. Invenergy's Natural Gas Peaking Proposals

Q. PLEASE DESCRIBE INVENERGY'S PROPOSALS.

A. Invenergy offered two separate proposals for new peakers. The first was for one additional CT at its existing Cannon Falls site, and the second was for two CTs at a new site located near the Hampton Corners Substation in Dakota County. These CTs were a different type than those proposed by the Company, and each had an estimated capacity value of 150 MW.

3. Calpine's Natural Gas Intermediate Proposal

Q. PLEASE DESCRIBE CALPINE'S PROPOSAL.

A. Calpine proposed an expansion of its existing natural gas combined cycle (CC) plant located in Mankato (MEC II). The expansion of MEC II had a proposed in-service date of June 2017 with a term of 20 years, and adds approximately 278 MW of summer capacity to the Company's system.

4. Great River Energy (GRE) System Capacity Proposal

Q. PLEASE SUMMARIZE GRE'S SYSTEM CAPACITY PROPOSAL.

A. GRE offered a three-year capacity purchase for either 100 MW or 200 MW. This proposal was to be for MISO Zone 1 resource credits only; no energy or generation would be associated with this purchase. The purchase would have covered 2016, 2017, and 2018, potentially allowing a delay of the in-service dates of one or more of the other proposals.

5. Aurora Solar Proposal

Q. PLEASE SUMMARIZE THE AURORA SOLAR PROPOSAL.

A. Aurora Solar's developer offered a 100 MW (ac) solar project with a targeted in-service date of December 2016. The project was proposed with up to 31 sites throughout the Company's service territory, with a capacity factor of approximately 22 percent and an accredited capacity of 71 MW.

The Aurora Solar Project would consist of distributed solar facilities located at up to 24 sites in Minnesota, and ranging in size from 2 to 10 MW. Each solar facility would interconnect to the Company's distribution substations, utilizing excess available transfer capability to inject power into the system at distribution voltage.

The PPA was based upon the Company's Model Solar PPA, which has been used in several jurisdictions to procure solar energy. This allowed the Company to utilize standardized terms and conditions that it has used with other solar generation, resulting in enhanced certainty and consistency with other Company contracts.

Q. CAN A SOLAR PROJECT MEET A PORTION OF THE COMPANY'S IDENTIFIED CAPACITY NEED?

A. Yes. MISO rules provide a methodology to calculate the accredited capacity for solar resources so they can be used to meet a portion of the capacity need. While the Aurora Solar bid contained information indicating the expected accredited capacity to be 71 MW, the Company's studies indicated accredited capacity for this type of solar PV installation was likely to be in the range of 50 MW to 60 MW. Aurora committed to having 71 MW of the project accredited as a capacity resource.

C. Strategist Analysis of Proposals in the CAP Proceeding

Q. HOW DID THE COMPANY EVALUATE THE COMPETITIVE BID PROPOSALS IN THE CAP PROCEEDING?

A. We used our Strategist resource planning software to evaluate all the proposals submitted in the CAP proceeding. Through dynamic optimization, Strategist identified the lowest-cost combination of the competitive resource proposals based on their present value of societal costs (PVSC), i.e. including externalities and an adder for carbon dioxide production. In addition to the least cost combination of proposed resources, Strategist identified numerous other plans. We compared these to the least cost plan to identify which factors were driving the Strategist results. Finally, we conducted sensitivity tests on the least cost and sub-optimal plans to see if the rank order of the proposals would change under different input assumptions.

Q. PLEASE DESCRIBE THE STRATEGIST MODEL AND HOW THE COMPANY HAS USED THIS MODEL IN THE PAST.

A. The Strategist resource planning model is a computer simulation model that is used to identify the lowest cost resources to meet established reserve margin requirements. The Company has utilized the Strategist model in several other resource planning-related dockets, and the software is used extensively throughout the country.

The model begins with a forecast of the utility's peak customer demand, to which a minimum reserve margin percentage is added to arrive at a minimum total capacity value that the utility must have to ensure reliable service to its customers.

The model then accounts for all of the utility's existing generation resources and how much those contribute to meeting the required reserve margin. If the model identifies a short fall in the required capacity (Capacity Need), it simulates the addition of a resource, or combination of resources, to meet the reserve margin target. One of the unique advantages of the Strategist model is that not only will it identify the lowest cost resource to fill a capacity need, it will also identify all of the sub-optimal resource combinations and their costs. Inspection of these sub-optimal plans provides valuable insight into the cost differences between resources.

The model includes a detailed hourly generation dispatch simulation where generators are ranked from lowest to highest based on generation costs and then dispatched one-by-one in order to meet customers' hourly demand. Through this simulation, Strategist tracks total fuel costs, total generating hours, and associated air emissions.

Q. HOW WERE THE PROPOSALS IN THE CAP PROCEEDING MODELED IN STRATEGIST?

A. We used the data provided by each bidder as inputs to the Strategist model. For MEC II, we added our estimated cost of firm gas supply; for Invenergy's proposals we added the estimated cost of interruptible gas supply.

Because there was a particularly large amount of forecasted capacity need – growing from 150 MW in 2017 to 500 MW by 2019 – and no single project could meet the entire forecasted need, we analyzed the projects as portfolios of several projects with different in-service dates so that each portfolio could be used to generally meet the identified needs in the expected time-frame. Exhibit____(PJM-1), Schedule 3 provides the Strategist Scenario Results we ran for the CAP Proceeding showing annual results for each bid in each of the top two plans, and an annual cost comparison to Plan 1 that shows the primary drivers of the PVSC differences.

Information on the costs and benefits of individual bids were determined by analyzing the annual cost differences between certain portfolios. Given the number of proposal combinations generated by Strategist, we were able to identify the cost differences between any two proposals in the CAP Proceeding. Exhibit____(PJM-1), Schedule 4 provides a comprehensive set of cost comparisons based on this method.

Q. PLEASE SUMMARIZE THE STRATEGIST MODELING RESULTS FROM THE CAP PROCEEDING.

A. Table 1 below presents the PVSC for the top 20 combinations of bids that had at least 307 MW of capacity by 2019.

Table 1: Top 20 CAP Proceeding Proposal Combinations (PVSC)

	Selected Bids	Total Long Term Capacity	2013-2050 PVSC $millions	Difference From Plan 1
Plan 1	Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2018 - 208MW	358 MW	$45,366	
Plan 2	Calpine Mankato - 2017 - 278MW Black Dog 6 - 2019 - 208MW	486 MW	$45,368	+ $1.8
Plan 3	GRE Short Term - 2016 - 100MW Red River Valley 1 - 2018 - 208MW Black Dog 6 - 2019 - 208MW	416 MW	$45,368	+ $2.2
Plan 4	Invenergy Cannon Falls - 2016 - 150MW GRE Short Term - 2016 - 100MW Black Dog 6 - 2019 - 208MW	358 MW	$45,371	+ $5.1
Plan 5	Black Dog 6 - 2017 - 208MW Red River Valley 1 - 2018 - 208MW	416 MW	$45,375	+ $9.0
Plan 6	Calpine Mankato - 2017 - 278MW Black Dog 6 - 2018 - 208MW	486 MW	$45,375	+ $9.1
Plan 7	GRE Short Term - 2016 - 100MW Black Dog 6 - 2018 - 208MW Red River Valley 1 - 2018 - 208MW	416 MW	$45,376	+ $9.8
Plan 8	Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2017 - 208MW	358 MW	$45,377	+ $10.9
Plan 9	Invenergy Cannon Falls - 2016 - 150MW GRE Short Term - 2016 - 100MW Black Dog 6 - 2018 - 208MW	358 MW	$45,379	+ $12.6

Table 1: (cont'd)

	Selected Bids	Total Long Term Capacity	2013-2050 PVSC $millions	Difference From Plan 1
Plan 10	GRE Short Term - 2016 - 100MW Calpine Mankato - 2017 - 278MW Black Dog 6 - 2019 - 208MW	486 MW	$45,381	+ $14.2
Plan 11	GRE Short Term - 2016 - 200MW Red River Valley 1 - 2018 - 208MW Black Dog 6 - 2019 - 208MW	416 MW	$45,383	+ $16.8
Plan 12	Invenergy Cannon Falls - 2016 - 150MW Red River Valley 1 - 2018 - 208MW Black Dog 6 - 2019 - 208MW	566 MW	$45,384	+ $17.8
Plan 13	Invenergy Cannon Falls - 2016 - 150MW GRE Short Term - 2016 - 200MW Black Dog 6 - 2019 - 208MW	358 MW	$45,386	+ $19.6
Plan 14	Calpine Mankato - 2017 - 278MW Black Dog 6 - 2017 - 208MW	486 MW	$45,386	+ $20.0
Plan 15	Invenergy Hampton Corners - 2016 - 300MW Black Dog 6 - 2019 - 208MW	508 MW	$45,387	+ $20.6
Plan 16	GRE Short Term - 2016 - 100MW Calpine Mankato - 2017 - 278MW Black Dog 6 - 2018 - 208MW	486 MW	$45,388	+ $21.5
Plan 17	Invenergy Cannon Falls - 2016 - 150MW GRE Short Term - 2016 - 100MW Black Dog 6 - 2017 - 208MW	358 MW	$45,389	+ $23.0
Plan 18	Invenergy Cannon Falls - 2016 - 150MW GRE Short Term - 2016 - 200MW Black Dog 6 - 2018 - 208MW	358 MW	$45,393	+ $27.0
Plan 19	GRE Short Term - 2016 - 200MW Calpine Mankato - 2017 - 278MW Black Dog 6 - 2019 - 208MW	486 MW	$45,395	+ $28.7
Plan 20	Invenergy Cannon Falls - 2016 - 150MW Calpine Mankato - 2017 - 278MW Black Dog 6 - 2019 - 208MW	636 MW	$45,396	+ $29.4

Q. DID THE COMPANY EVALUATE THE PRESENT VALUE REVENUE REQUIREMENT (PVRR) OF THE COMPETITIVE BID PROPOSALS IN THE MPUC CAP PROCEEDING?

A. Minnesota law and rules require that we account for externalities in our resource selection analyses. Consequently, the CAP Proceeding provided only PVSC analyses. I discuss our PVRR analysis performed in the North Dakota proceeding (NDSPC Case No. PU-15-095), below.

Q. DID THE COMPANY UPDATE THIS ANALYSIS IN THE CAP PROCEEDING?

A. No. Our initial Strategist analysis was the underlying basis for the evaluation of bids in the CAP proceeding.

Q. YOU MENTIONED UPDATING YOUR FORECASTS ARE PART OF YOUR STANDARD OPERATIONS. DID THE COMPANY UPDATE ITS FORECAST DURING THE CAP PROCEEDING?

A. Yes. At the time we made our initial CAP filing in Minnesota (Docket No. E002/CN-12-1240), the Fall 2011 Forecast was the most up-to-date information available confirming the need for the resource acquisitions we proposed in the proceeding. On September 23, 2014, we made a compliance filing in which we again updated our 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. Our updated Resource Need Assessment in the fall of 2014 indicated a capacity surplus of 250 MW in 2017 decreasing to 100 MW in 2019. We suggested in our September 23, 2014 compliance filing that the 2014 forecast update supported a delay of two years or more in adding any new capacity to our system. I provide our September 2014 Compliance Filing as Exhibit____(PJM-1), Schedule 5.

Q. DID THE COMPANY CHANGE ITS RECOMMENDATIONS IN THE CAP PROCEEDING BASED ON THE CHANGING LOAD FORECASTS?

A. Yes. Our compliance filing suggested that given the slackening of demand and the potential for a capacity surplus in 2017 it would be prudent to allow the Company to renegotiate PPAs with Calpine and Invenergy with pricing to reflect in-service dates ranging from 2019-2021 and to similarly refresh the Company's own Black Dog Unit 6 proposal. In that same filing, the Company proposed that the Minnesota Public Utilities Commission (MPUC) defer Aurora Solar and consider that project in light of the PPAs being developed through the 187 MW Portfolio RFP process, which was pending at the time.

Q. DID THE MPUC ACCEPT THE COMPANY'S NEW RECOMMENDATION?

A. No. In its February 5, 2015 Order selecting the Aurora Solar PPA for execution, the MPUC found that it was more appropriate to rely upon the forecasts that were used in our 2010 IRP, 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. 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…
>
> 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. DID THE COMPANY CHALLENGE THE MPUC'S ORDER?

A. No. Despite having advocated that updated forecasts supported delaying capacity additions, the Company ultimately concurred with the MPUC's Order.

Q. WHY DID THE COMPANY CONCUR WITH THE MPUC'S ORDER?

A. When we analyzed the MPUC's reasoning behind the order, we believed that the conservative approach was reasonable under the circumstances.

Q. DID THE COMPANY EVALUATE THE PRESENT VALUE REVENUE REQUIREMENT (PVRR) FOR THE AURORA SOLAR PROJECT AT ANY TIME?

A. Yes. We applied for an Advanced Determination of Prudence in the state of North Dakota for the Aurora PPA in 2015 that provided Present Value Revenue Requirements (PVRR) values for consideration. Below is the PVRR assessment of the CAP resources that was provided in the testimony of Company Witness Mr. Paul B. Johnson in the North Dakota Advance Determination of Prudence proceeding (Case No. PU-15-096).

Table 2: PVRR Results ($millions)

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

Table 3: Incremental PVRR from Base Case ($millions)

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

Q. PLEASE DESCRIBE THE RESULTS OF THE PVRR ANALYSIS.

A. The results demonstrate that the addition of the Calpine PPA together with Black Dog Unit 6 provides the biggest PVRR savings when looking at a combination of resource additions. Including the Geronimo Aurora Solar PPA with Calpine and Black Dog reduces overall savings, but the package of resources still provides a net PVRR reduction in all scenarios except the low gas case.

Q. IS THE PVRR ANALYSIS MATERIALLY DIFFERENT THAN THE PVSC ANALYSIS?

A. No. Because all the bids but the GRE proposal and Aurora Solar project were gas-fired generation, the impacts of externalities on the bulk of projects analyzed were more or less equalized on a PVSC basis so that the PVRR outcomes generally resulted in similar project rankings. The main impact of excluding externalities from the analysis was that it disadvantaged the Aurora Solar project. The equalizing effect of the gas-fired generation is reflected in the PVRR and PVSC tables included above – which show similar outcomes across all scenarios.

Q. WHY WAS AURORA SOLAR NOT IN ANY OF THE TOP 20 STRATEGIST PLANS IN THE CAP PROCEEDING?

A. Aurora Solar was not in the top 20 Strategist plans due to its higher cost in comparison to the other proposals considered in the CAP Proceeding. Table 4 below, which was provided in the testimony of Paul B. Johnson as part of the Aurora ADP, demonstrates this.

Table 4 – PVRR Impact of Geronimo Solar

Net PVRR Cost/Savings of Geronimo PPA for Key Sensitivities

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

Notably at the time, the Company had not conducted a detailed analysis to determine what the line loss savings might be for the project, and line loss savings were not included in the Strategist analysis. Generally, for distributed solar projects that avoid all transmission and distribution line losses, we estimate the savings to be equal to 7 percent of the energy and capacity benefits. When applying the full 7 percent to the energy and capacity credit savings estimated for the Aurora Solar, the PVSC of the line loss savings would have added an additional $10 million - not enough to move the Aurora Solar into the top twenty portfolios.

D. Aurora Solar Project is Prudent, Economical, and Efficient

Q IS THE AURORA SOLAR PROJECT A LEAST-COST RESOURCE?

A. No. None of the analyses we conducted suggest that the Aurora Project is the least cost resource to meet our capacity needs.

Q. DOES THIS MEAN THE PROJECT IS NOT PRUDENT?

A. No. Mr. Chandarana, in his Direct Testimony, discusses the overall context of the project and how, when viewed in that light, it is prudent, economic, and efficient. I also note that qualitative benefits of the project are material.

For example, we identified two qualitative benefits of the Aurora Solar PPA in addition to the quantifiable benefits identified above: (1) an environmental hedge benefit; and (2) the ITC qualification benefit.

Q. PLEASE DESCRIBE AURORA SOLAR'S ENVIRONMENTAL HEDGE BENEFIT.

A. Solar generation provides an emissions-free energy source that works well in combination with other capacity resources, such as natural gas facilities. Increasing carbon-free generation positions the Company well for the challenges of the future, including any potential environmental regulations.

Aurora Solar also positions us to address known long-term changes to the NSP System beyond 2024. These changes will require the Company to replace or extend the operating lives of nearly 75 percent of the energy-producing resources on the NSP System over the next 20 years.

Q. PLEASE EXPLAIN THE ITC QUALIFICATION BENEFIT OF THE AURORA SOLAR PPA.

A. The Aurora Solar Project was dependent upon obtaining the 30 percent ITC to offset a significant proportion of the costs of the project. At the time, the 30 percent ITC applied to any project that went into service by the end of 2016. The ITC was scheduled to automatically reduce to 10 percent for projects that went into service after 2016, but has since been extended. Despite the subsequent extension, at the time there was a benefit in pursuing additional solar generation that could capture the higher ITC generation subsidy.

Q. ARE THERE OTHER QUALITATIVE BENEFITS OF AURORA SOLAR?

A. Yes, particularly during this time of significant change and uncertainty in the utility industry. We believe that our resource decisions should anticipate industry evolutions and market change. Accordingly, we ascribe additional value to resources that provide a fuel price hedge, resource diversity, and system integration experience with distributed resources, or other emerging technology. I believe there is value in gaining system integration experience with distributed resources. Solar is a developing resource and, as stated above, making utility scale distributed additions to the NSP System will provide us with operational experience with this type of resource.

IV. THE 187 MW PORTFOLIO

A. 187 MW Portfolio Project Description

Q. DESCRIBE THE SOLAR PROJECTS IN THE 187 MW PORTFOLIO.

A. The three solar projects that together constituted our proposed acquisition of 187 MW of solar generation resources for the NSP System are:

- Marshall Solar – a 62.25 MW project located near Marshall, Minnesota to be developed by NextEra,
- North Star Solar – a 100 MW project located near North Branch, Minnesota to be developed by Community Energy Resources, and
- MN Solar I – a 24.75 MW project located near Tracy, Minnesota to be developed by juwi Solar, Inc.

1. Marshall Solar

Q. PLEASE DESCRIBE THE MARSHALL SOLAR PROJECT.

A. The Marshall Solar project is a 62.25 MW solar energy generation facility on approximately 464 acres in an agricultural area east of Marshall, Minnesota in Lyon County. The project consists of 30º fixed tilt configuration, photovoltaic modules and interconnects at the existing Company Lyon County substation at 69 kV.

Q. WHAT WAS THE MARSHALL SOLAR PROJECT'S CONSTRUCTION SCHEDULE?

A. The bulk of construction of the Marshall Solar project began in spring 2016, with engineering, procurement and some construction occurring in 2015. Marshall Solar became fully operational in January 2017.

2. North Star Solar

Q. PLEASE DESCRIBE THE NORTH STAR SOLAR PROJECT.

A. North Star Solar is a 100 MW solar energy generation facility located on approximately 800 acres in an agricultural area southeast of North Branch, Minnesota in Chisago County. North Star Solar consists of single axis tracking panels. The project interconnects at 115 kV to the existing NSP Chisago County Substation.

Q. WHAT WAS THE NORTH STAR SOLAR PROJECT'S CONSTRUCTION SCHEDULE?

A. As with Marshall Solar, the construction schedule was designed so that the project would qualify for the 30 percent Federal ITC to offset project construction costs. Engineering, procurement and some construction occurred in 2015, with the bulk of construction of the North Star Solar project in 2016. North Star Solar became fully operational in December 2016.

3. MN Solar I

Q. PLEASE DESCRIBE MN SOLAR I.

A. MN Solar I was a proposed 24.75 MW project to be located near Tracy, Minnesota. Although approved by the MPUC in the 187 MW solar portfolio docket, MN Solar I exercised its rights to terminate its PPA in a notice provided to the Company on May 10, 2016 due to issues in obtaining an Interconnection Agreement.

Q. DOES THE TERMINATION OF THE MN SOLAR I PPA AFFECT THE ANALYSIS THE COMPANY PERFORMED IN EVALUATING THE 187 MW PORTFOLIO?

A. Not significantly. The MN Solar I PPA comprised only 13 percent of the total portfolio. The qualitative benefits such as fuel and environmental hedging are not affected by the termination of the MN Solar I PPA. The quantitative effect of MN Solar I PPA termination on ratepayers is similarly negligible.

B. Minnesota's Solar Energy Standard (SES).

Q. WHY DID THE COMPANY PROPOSE THE 187 MW SOLAR PORTFOLIO RESOURCE ADDITION?

A. The Company proposed acquiring the 187 MW Solar Portfolio primarily to comply with Minnesota's SES. This solar energy displaces fuel and energy that would have been purchased or produced in the absence of this new generation. As a fixed price source of clean energy, the solar energy provides a hedge against increases in natural gas fuel prices and future environmental regulation.

Q. WHAT LED THE COMPANY TO ISSUE ITS SOLAR REQUEST FOR PROPOSALS (RFP) IN 2014?

A. We determined that we should issue an RFP to help ensure that we would have an adequate number of options to consider in the process of adding solar resources to our system to meet the Minnesota SES. Issuing the RFP in 2014 helped ensure that any projects selected could meet the December 31, 2016 expiration deadline for the 30 percent Federal Investment Tax Credit (ITC), which allowed the Company to capture more attractive pricing for the projects.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE 187 MW SOLAR PORTFOLIO AND THE CAP PROCEEDING?

A. We released our RFP as the CAP Proceeding was underway given the impending expiration of the Federal ITC. We believed that probing the market to determine project pricing that could capture the ITC would potentially provide our customers with well-priced projects to meet SES requirements. Because the Aurora Solar Project was being evaluated as a capacity resource, and our RFP was seeking projects for SES compliance, we believed that running the two processes concurrently was prudent. Additionally, we shared with the MPUC our conclusion that the projects emerging from the RFP made the Aurora Project look less attractive.

C. 187 MW Portfolio Process

Q. PLEASE DESCRIBE THE COMPANY'S RFP.

A. We issued the Solar RFP on April 22, 2014, identifying eligible projects as those based on a photovoltaic solar resource with a nominal electrical output of at least five MW (ac), that offered to sell to the Company all energy, associated capacity, ancillary services, and all RECs generated by the project.

Q. WHAT WAS THE RESPONSE TO THE RFP?

A. Developer response to our RFP was robust. There were 111 proposals totaling over 2,100 MW of solar photovoltaic generating capacity submitted by 36 developers. Individual projects ranged in size from 5 MW to 100 MW. Submissions included a number of ownership structures from independently owned and operated facilities to offers of partnerships with the Company.

Q. DID THE COMPANY CONSIDER ALTERNATIVE ENERGY SOURCES OTHER THAN SOLAR?

A. The RFP was designed to acquire solar energy as its purpose was to probe the market to obtain resources for compliance with Minnesota's SES. Because our goal was SES compliance, we did not request proposals from other generation types. This is in contrast to the selection of the Aurora Solar project, which was acquired in a capacity acquisition process and was considered against other generation types to meet capacity needs.

However, while the RFP was limited to solar proposals, it is important to note that our Strategist modeling and the PVSC and PVRR impacts under different sensitivities provided insights into how this solar compared to other types of resources. The Strategist modeling analysis compared the overall system costs with and without the addition of the solar portfolio. The solar additions provide value by avoiding fossil fuel generation and market purchases, as well as by providing capacity. The benefits of avoided CO_2 emissions are shown in the PVSC view. Since the solar additions drove a small net increase in PVRR and a larger decrease in PVSC, the model indicates that these resources are fairly competitive with the resources in our existing generation portfolio. I discuss the economic analysis of the 187 MW Solar Portfolio further below.

Q. HOW DID THE COMPANY ANALYZE THE PROPOSALS?

A. Our Resource Planning department led the evaluation team, logging all bids on a tracking spreadsheet and maintaining the bids in a locked room accessible only by the Company's Resource Planning group. Initial screening identified 15 projects, in aggregate totaling 630 MW of generation capacity, submitted by 11 companies, each with a levelized energy cost of $85/MWh or less. Copies of these proposals were then provided to our Transmission, Land and Siting, and Purchased Power staff for further evaluation.

A significant consideration for any project is its ability to interconnect with the transmission system. Therefore, our Transmission Access group performed a detailed multi-factor review of the status of each project's MISO interconnection request and potential transmission requirements. This review identified potential significant issues around transmission interconnection cost and curtailment risk for several of the projects. Based on this analysis, the Transmission Access group recommended that a number of these projects be eliminated from further consideration.

Q. WHY DID THE COMPANY CONCLUDE IN 2014 THAT IT SHOULD BUY ENOUGH SOLAR ENERGY TO MEET THE SES RATHER THAN SPREAD ITS ACQUISITION OF SOLAR RESOURCES OVER TIME?

A. As I mentioned previously, the Federal ITC of 30 percent represents a significant incentive to developers that results in very attractive pricing for solar energy at this time. Although the ITC has subsequently been extended, at the time the incentive was scheduled to decrease significantly to 10 percent at the end of 2016, with future federal incentives increasingly uncertain. We felt the circumstances warranted making a substantial, near-term purchase in order to capitalize on the ITC.

Additionally, the MPUC's banking rules for solar energy allow us to accumulate tradable solar Renewable Energy Certificates (S-RECs) before 2020. Marshall Solar and North Star Solar result in a significant bank of RECs that the Company can use to maintain compliance throughout the 2020s. The bank is projected to be large enough to support percentages of sales higher than 1.5 percent if necessary. Early compliance coupled with the S-REC banking standards provides the flexibility to make subsequent solar additions if it is in our customers' best interest, while ensuring compliance with the SES at a reasonable cost.

D. Economic Analysis of the 187 MW Portfolio

Q. HOW DID THE COMPANY EVALUATE THE 187 MW SOLAR PORTFOLIO?

A. The Company performed two evaluations of the 187 MW Solar Portfolio: a quantitative analysis and a qualitative analysis in the relevant MPUC proceeding and NDPSC proceeding (MPUC Docket No. E002/M-14-162) NDPSC Case No. PU-14-810). Based on the outcome of these analyses, we determined that the acquisition of the 187 MW Solar Portfolio was a prudent resource acquisition to allow us to cost effectively meet our Minnesota SES requirements while providing a source of clean energy that has key fuel and environmental hedging benefits. In addition, as noted above, while solar generation is primarily a source of clean energy, it also provides some additional capacity to the system that can be used to offset future capacity needs.

To perform the quantitative analyses, we used the Strategist resource planning model and present the results in both PVRR and PVSC terms. To assess the impact on customer costs, we simulated the operation of the NSP System with and without the addition of the 187 MW Solar Portfolio.

We also performed a more qualitative analysis to identify the non-economic benefits of the 187 MW Solar Portfolio to the NSP System. When the quantitative analysis and the qualitative analysis are taken together, the 187 MW Solar Portfolio will add a relatively minor net cost to the NSP System, but provide material qualitative benefits which demonstrate the prudence of these resource additions.

1. Quantitative Analysis

Q. WHAT WERE THE RESULTS OF THE QUANTITATIVE ANALYSIS OF THE 187 MW SOLAR PORTFOLIO?

A. Our Reference Case analysis estimated that the cost of energy from the 187 MW Solar Portfolio over the 25-year term of the PPAs, without considering any CO2 or externality costs, was approximately $14 million higher on a PVRR basis and approximately $47 million lower on a PVSC basis. We also analyzed the impact of adding the 187 MW Solar Portfolio to the system under various sensitivities, including a scenario where natural gas prices stay below our current market forecasts, a scenario where the system cannot make market purchases to meet increasing demand (Markets Off), and scenarios when capacity factors of the 187 MW Solar Portfolio are higher or lower than expected.

Table 5 below presents the results of the total system costs with and without the 187 MW Solar addition as provided in the Minnesota Petition for Approval of a Solar Portfolio to Meet Initial Solar Energy Standard Compliance (Docket No. E002/M-14-162).

Table 5: Economic Analysis

PVRR Cost ($ millions)	Reference Case	Low Gas (1.4% growth rate)	Zero CO2 Externalities	Markets Off	+5% capacity Factor	-5% capacity factor
RFP Portfolio compared to displaced energy (net benefit)/ net cost	($47)	($16)	$14	($56)	($44)	($49)

Please note that the sensitivity labeled "Zero CO2 Externalities" represents the PVRR analysis of the 187 MW Portfolio.

Q. WHAT DO YOU CONCLUDE SINCE THE PVRR ANALYSIS INDICATES NET COSTS TO THE NSP SYSTEM AND THE PVSC ANALYSIS INDICATES NET BENEFITS TO THE NSP SYSTEM?

A. The results indicate that the solar portfolio represented an opportunity to comply with solar standards at a reasonable cost. The $14 million net increase in PVRR is not significant relative to the overall system cost. The limited cost impacts coupled with the impending decline in the ITC from 30 percent to 10 percent provided compelling support at the time to move forward with the portfolio.

Q. DID YOU PERFORM A BREAK-EVEN ANALYSIS TO DETERMINE A WHAT CO_2 COST THE BENEFITS OF THE SOLAR PORTFOLIO WERE EQUIVALENT TO THE COSTS?

A. Yes. The break-even cost will vary somewhat depending on whether the CO_2 costs are allowed to impact the dispatch of resources. Assuming that that CO_2 will not impact the dispatch, I calculate that the benefits and cost of the solar portfolio are equal when a CO_2 cost of $5.64 per ton is included in the modeling beginning in 2019.

Q. WHAT WAS THE BASIS FOR THIS QUANTITATIVE ANALYSIS?

A. Our quantitative analysis was based on the cost of electricity displaced by the 187 MW Solar Portfolio as well as the accredited capacity value of this resource.

The NSP System is dispatched by the MISO and solar production is generally dispatched ahead of other generation such as natural gas and coal-based generation. Consequently, the more solar energy produced, the less other fossil generation is operated and the less fossil fuel must be purchased. Therefore, when the energy from solar resources is produced, it displaces a similar amount of fuel that would have been acquired by the Company or other purchases of market energy. Our Base Case assumed a displacement of fuel that would have been purchased to generate approximately 370,000 MWh of fossil generation, accounting for the majority of differences in cost of system operation with and without the addition of the 187 MW Solar Portfolio.

Additionally, the 187 MW Solar Portfolio started providing accredited capacity in June 2017. MISO has initially assigned a capacity accreditation of 50 percent for all solar resources.

Future capacity accreditation values will be dependent upon actual production at each project. The solar projects are required to provide MISO with a minimum of 30 consecutive days of historical data during June, July or August for the hours of 1500 – 1700 EST. For purposes of the economic evaluation, we assumed the projects will receive capacity accreditation for the 2018/2019 planning year but were able to participate in the 2017/2018 planning year auction one year earlier than expected.

Q. FOR CONTEXT, WHAT IS THE MIX OF ENERGY THAT IS DISPLACED BY THE 187 MW SOLAR PORTFOLIO?

A. Figure 2 below illustrates the results of the Strategist dispatch simulations under the Markets Off scenario; that is, Strategist only allows increasing customer demand to be met by NSP System resources not by purchases of energy from the market. In this scenario, the majority of the solar generation, approximately 84 percent, displaces natural gas-based generation, with the remaining expected to displace coal purchases. This reflects the fact that during on peak periods more gas generation is dispatched to meet on peak conditions as compared to off peak periods when much less gas generation is needed.

Figure 2: Displaced Generation (Markets Off)

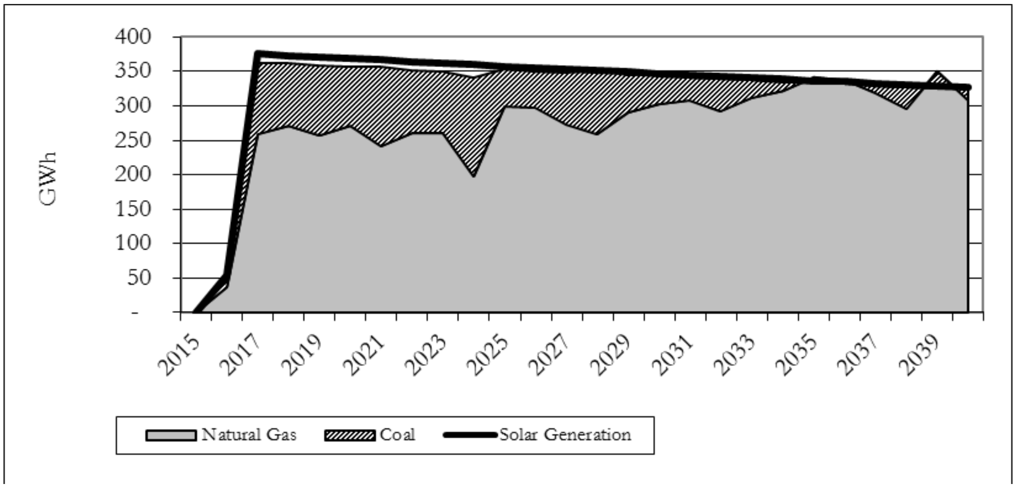
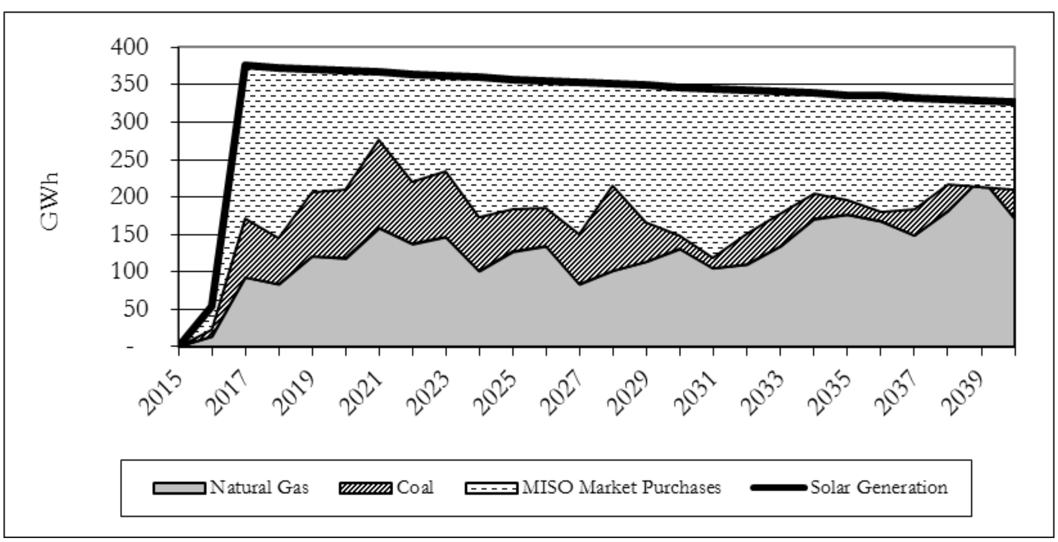


Figure 3 below illustrates the results of the Strategist dispatch simulations in a "Markets On" scenario, where Strategist may choose to purchase market energy to meet system needs. In this scenario, approximately 40 percent of the solar generation displaces natural gas-based generation, 15 percent displaces coal, and 45 percent displaces the purchase of market energy.

Figure 3: Displaced Generation (Markets On)



2. *Qualitative Benefits*

Q. WHAT QUALITATIVE BENEFITS DOES THE 187 MW SOLAR PORTFOLIO PROVIDE?

A. The addition of the 187 MW Solar Portfolio acts as a hedge against higher natural gas prices and future environmental regulations through the displacement of natural gas and coal-based generation. If the Company were not to acquire these resources, future levels of natural gas consumption and MISO market purchases would be higher, creating higher cost uncertainty for our customers.

Q. HOW DOES THE 187 MW SOLAR PORTFOLIO PROVIDE THESE QUALITATIVE BENEFITS?

A. As I mentioned, the 187 MW Solar Portfolio displaces the purchase of fossil fuel, including fuel for gas-fired generation, as well as market purchases and replaces it with fixed price clean energy. Displacement of this generation by the 187 MW Solar Portfolio provides qualitative benefits to the NSP System and therefore to our customers.

Additionally, the displacement of variable cost fossil-based and market energy with a fixed price energy source provides a commodity hedge against volatile gas process and market risk. The fixed price certainty provides an additional qualitative benefit to our customers.

Q. ARE THE MARSHALL SOLAR AND NORTH STAR SOLAR PRUDENT, ECONOMICAL AND EFFICIENT RESOURCES?

A. Yes, I believe so. These projects were selected through a competitive RFP to provide the Company with low cost projects to meet Minnesota SES compliance. Our economic analysis of these resources bears this out. Additionally, moving forward with these projects for SES compliance is not in conflict with the outcome of the CAP Proceeding due to the different purpose for those resources; namely, to conservatively meet a capacity need.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.