MINNESOTA DEPARTMENT OF COMMERCE

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December 4, 2015

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: Comments of the Minnesota Department of Commerce, Division of Energy Resources
Docket No. E002/M-15-330

Dear Mr. Wolf:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

> Petition of Northern States Power Company for Approval of Cost Recovery of the North Dakota Share of the Costs of the Aurora Solar Power Purchase Agreement.

The petition was filed on October 20, 2015 by:

> Amy S. Fredregill
> Manager Resource Planning and Strategy
> Northern States Power Company
> 414 Nicollet Mall
> Minneapolis, MN 55401

The Department recommends that the Commission **reject Xcel's proposal to charge Minnesota ratepayers for the North Dakota share of costs** and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ STEVE RAKOW
Rates Analyst

SR/lt
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES

DOCKET NO. E002/M-15-330

I. INTRODUCTION

On April 3, 2015, Northern States Power Company d/b/a Xcel Energy (Xcel or the Company) filed a petition with the Minnesota Public Utilities Commission (Commission) requesting that the Commission:

- determine that the Aurora Power Purchase Agreement (PPA) is a reasonable and prudent approach to meeting Xcel's obligations under Minnesota's Solar Energy Standard (SES) as provided in Minnesota Statutes §216B.1645; and
- allow the Company to recover the Minnesota portion of the costs of the Aurora PPA via the Fuel Clause Rider.

On May 4, 2015, Aurora Distributed Solar, LLC (Aurora) filed comments supporting Xcel's petition and the Minnesota Department of Commerce (Department) filed comments recommending approval of Xcel's petition with conditions.

On May 14, 2015, Xcel and Aurora filed reply comments disagreeing with the Department's proposed conditions on cost recovery.

On August 20, 2015, the Commission issued its *Order Approving Power Purchase Agreement Under Minn. Stat. § 216B.1645, Subd. 1, Authorizing Cost Recovery Under Minn. Stat. § 216B.1645, Subd. 2, and Requiring Compliance Filing* (Order). The Order:

- approved Xcel's PPA with Aurora under Minnesota Statutes §216B.1645, Subd. 1;
- authorized recovery of the PPA's Minnesota-jurisdictional costs through the Company's fuel-clause rider under Minnesota Statutes §216B.1645, subd. 2; and
- required the Company to file a compliance filing on or before October 5, 2015 regarding its current status on compliance with Minnesota's SES.

On October 5, 2015, Xcel made a compliance filing updating the current status of the Company's compliance with Minnesota's SES.

On October 20, 2015, Xcel filed the Company's *Petition of Northern States Power Company for Approval of Cost Recovery of the North Dakota Share of the Costs of the Aurora Solar Power Purchase Agreement* (Petition). The Petition requests that the Commission authorize recovery of the North Dakota share of the costs of the Aurora PPA from Xcel's Minnesota retail customers.

II. DEPARTMENT ANALYSIS

A. GOVERNING STATUTE AND XCEL'S REQUEST

Xcel filed the Petition pursuant to Minnesota Statutes §216B.1645 which states in part:

> Subd. 1. Upon the petition of a public utility, the Public Utilities Commission shall approve or disapprove power purchase contracts, investments, or expenditures entered into or made by the utility to satisfy…the renewable energy objectives and standards set forth in section 216B.1691.[1]
>
> Subd. 2. Upon petition by a public utility, the commission shall approve or approve as modified a rate schedule providing for the automatic adjustment of charges to recover the expenses or costs approved by the commission under subdivision 1 … The commission may not approve recovery of the costs for that portion of the power generated from sources governed by this section that the utility sells into the wholesale market.

The Petition requested that the Commission authorize recovery of the North Dakota share of the costs of the Aurora PPA from Xcel's Minnesota retail customers. In support of its proposal, Xcel noted that 1) cost recovery for the Minnesota portion of the project has already been approved through the Company's Fuel Clause Rider under Minnesota Statutes §216B.1645, Subd. 2; and 2) the Aurora project contributes to the policy mandate outlined in Minnesota's SES.

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[1] Note that Minnesota Statutes §216B.1691 contains, among other things, Minnesota's solar energy standard and renewable energy standard.

B. ANALYSIS OF THE REQUEST

1. Resources for Minnesota Ratepayers

One presumption of Xcel's petition is that all of the costs of a resource that was selected within a process designed to acquire the best resource for Xcel's Northern States Power integrated system[2] should now be charged only to Minnesota ratepayers. There is no evidence anywhere in the extensive record of Docket No. E002/CN-12-1240 or this proceeding that Aurora's project would (or would not) be a cost effective resource to meet the energy and capacity needs of only Xcel's Minnesota ratepayers. All of the analysis comparing the various alternatives was done assuming the energy and capacity needs of Xcel's entire system. Further, Xcel's Petition provides no basis to determine that Aurora's project would be a reasonable resource for meeting only the general energy and capacity needs of Xcel's Minnesota ratepayers. A different bidding process would have been required to examine the new presumption in Xcel's petition.

The Department concludes that there is no basis to determine whether the Aurora PPA is a reasonable resource for meeting the general energy and capacity needs of Xcel's Minnesota ratepayers.

Moreover, Xcel states in its filing that the Company:

> …arranged a Letter Agreement with the project developer (Aurora Distributed Solar, LLC, a wholly-owned subsidiary of Enel Green Power North America), in which the Company waived its right under the condition precedent of the PPA to terminate the agreement and the developer agreed to reimburse the Company for North Dakota's jurisdictional share of the project costs if the Minnesota Commission declines this petition request.

Since there is already a market solution to address the effects of North Dakota's decision for its jurisdiction, namely that Enel Green Power will pay for that share of the costs, it is not reasonable to require Minnesota ratepayers to pay for those costs. Therefore, the Department recommends that the Commission reject Xcel's petition.

2. Resources for Minnesota Policy Requirements

Xcel's petition states that "[t]he Aurora project plays a role in two key aspects of the Company's energy vision—advancing renewable energy and targeting a 60 percent carbon dioxide emission reduction by 2030." While the Company's goals may be laudable, it would be helpful to examine how much the Aurora project is expected to contribute to Xcel's compliance with the renewable statutes. This information is also helpful, to examine given Xcel's choice not to exercise the condition precedent to terminate the PPA. Thus, the

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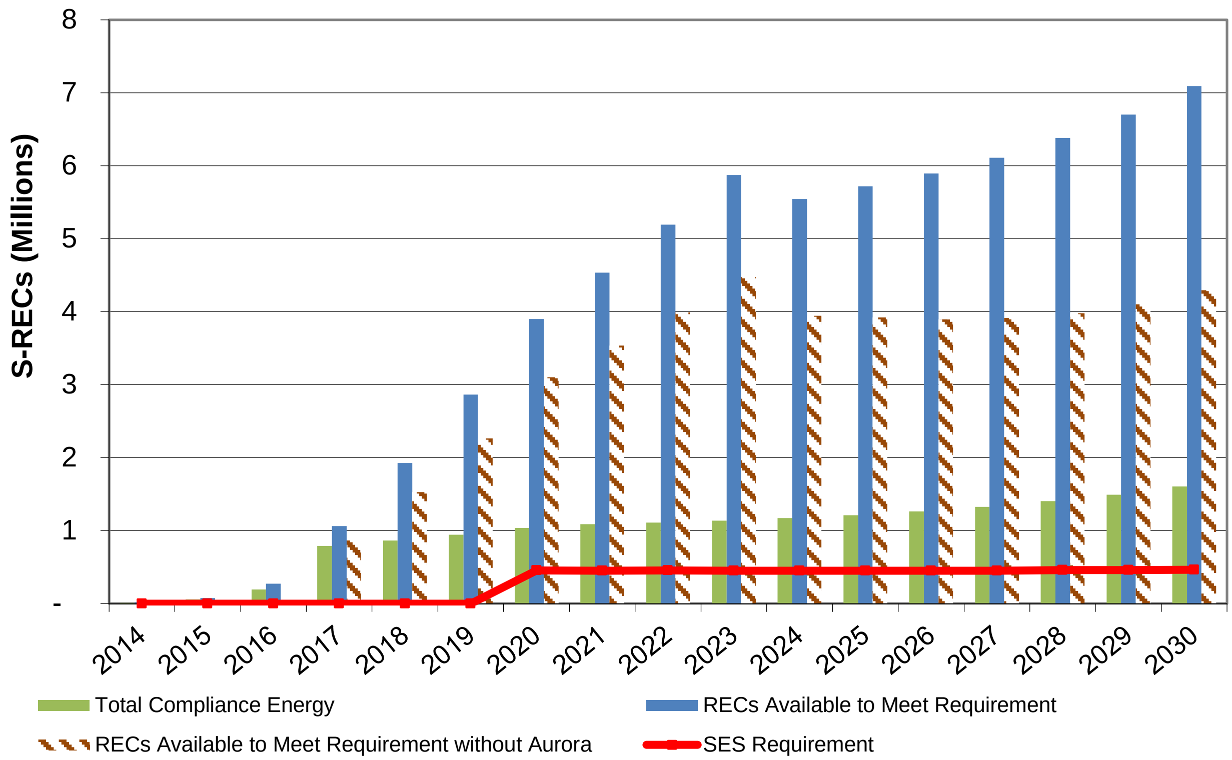
[2] Northern States Power Company's integrated system serves customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin.

Department provides the following information on the expected contribution of the Aurora in Xcel's compliance with Minnesota's SES policy.

The Department used Xcel's response to Clean Energy Organizations' Information Request No. 71 in Docket No. E002/RP-15-21, cited in Xcel's October 5, 2015 compliance filing in this docket, to determine the incremental impact of the entire Aurora project on Xcel's SES compliance. The Department added a series of columns depicting the number of credits available to meet Minnesota's SES and subtracted 200,000 credits annually as an estimate of the number of solar credits due to the Aurora project.[3] The result of the analysis is summarized below in Figure 1, which demonstrates that Aurora's project is expected to have only a minimal incremental impact in terms of Xcel achieving compliance with Minnesota's SES.

Figure 1: SES Compliance for Minnesota, Preferred Plan Supplement

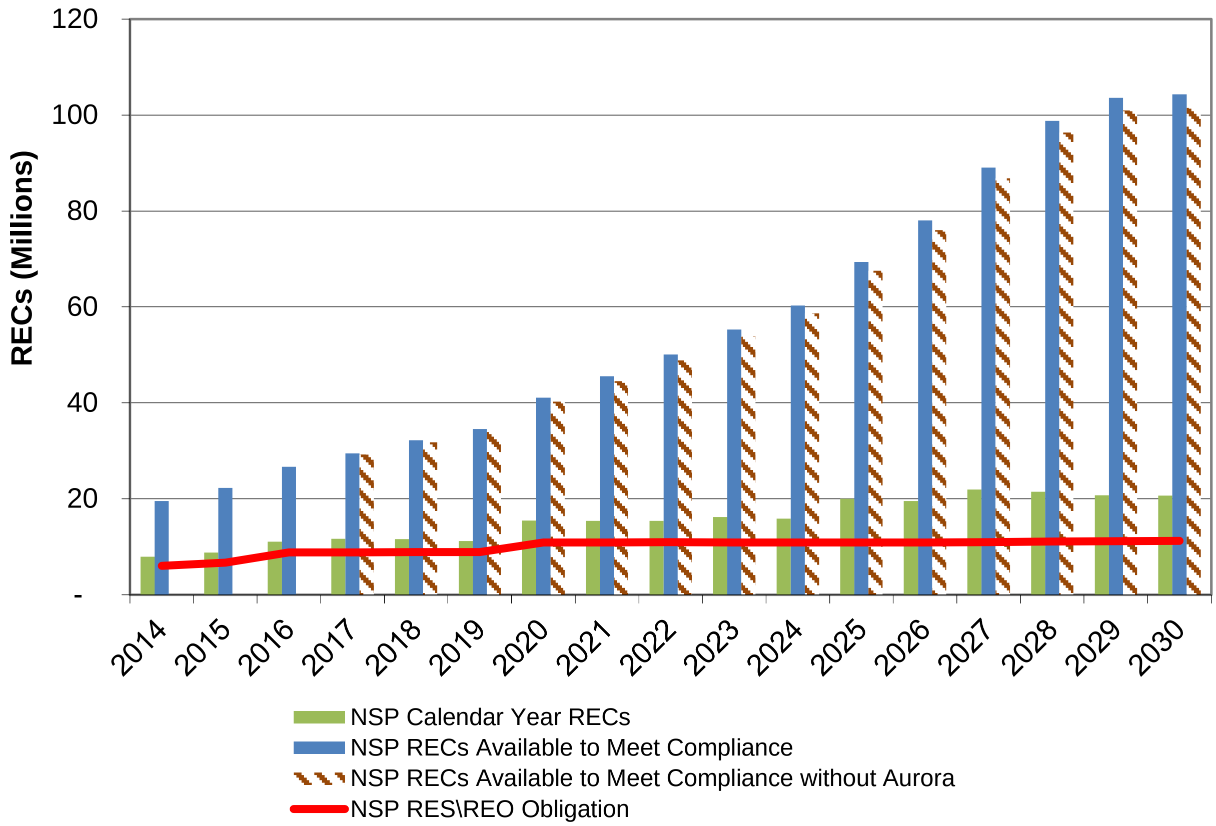


In addition, the Department used Xcel's response to Clean Energy Organizations' Information Request No. 71 in Docket No. E002/RP-15-21, cited in Xcel's October 5, 2015 compliance filing in this docket, to determine the incremental impact of Aurora's project on general RES compliance. The Department added a series of columns depicting the number of renewable energy credits (RECs) available to meet the Minnesota RES and subtracted

[3] Note that since the Petition states "the developer agreed to reimburse the Company for North Dakota's jurisdictional share of the project costs if the Minnesota Commission declines this petition request," rejection of the Petition should not lead to the entire project failing and the Department's analysis represents an unlikely, worst case scenario.

200,000 RECs annually due to the Aurora project. The result of the analysis, summarized below in Figure 2, demonstrates that the Aurora project is expected to have little to no incremental impact in terms of helping Xcel comply with Minnesota's RES.

Figure 2: RES Compliance for NSP System, Preferred Plan Supplement



III. DEPARTMENT RECOMMENDATION

The Department recommends that the Commission reject Xcel's proposal to charge to Minnesota ratepayers the costs disallowed for recovery by North Dakota. Since Enel Green Power has already agreed to pay for those costs, it is not reasonable to require Minnesota ratepayers to pay for those costs.

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PUBLIC VERSION – TRADE SECRET DATA EXCISED

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of Northern States Power Company's

Advance Determination of Prudence for its

345 MW Power Purchase Agreement with Mankato Energy Center,

LLC

Case No. PU-15-96

DIRECT TESTIMONY

OF

RICHARD A. POLICH, P.E.

ON BEHALF OF THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

ADVOCACY STAFF

August 28, 2015

28 PU-15-96 Filed 08/31/2015 Pages: 64
Pre-filed Testimony of Richard A. Polich with Exhibits 1 – 7
Public Service Commission
Mitch Armstrong, SAAG

Table of Contents

Q. Please state your name and place of employment.

A. My name is Richard A. Polich. I am employed by GDS Associates, Inc. ("GDS"), and my office is located at 1850 Parkway Place, Suite 800, Marietta, Georgia 30067.

Q. What position do you hold?

A. I hold the position of Managing Director.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this testimony on behalf of North Dakota Public Service Commission Advocacy Staff ("Staff")

Q. What is your educational background?

A. I graduated from the University of Michigan - Ann Arbor in August 1979 with a Bachelor of Science Engineering Degree in Nuclear Engineering, and a Bachelor of Science Engineering Degree in Mechanical Engineering.

In May 1990, I received a Master of Business Administration from the University of Michigan - Ann Arbor.

Q. Please describe your work experience.

A. In my role as both employee and consultant, I have had over 37 years of work experience in the energy sector, performing duties and services for myriad companies and organizations, and representing the interests of private and public constituencies throughout the country.

In May 1978, I joined Commonwealth Associates, Inc., located in Jackson, Michigan, as a Graduate Engineer and worked on several plant modification and new plant construction projects.

In May 1979, I joined Consumers Power Inc. (now called Consumers Energy), located in Jackson, Michigan, as an Associate Engineer in the Plant Engineering Services Department.

In April 1980, I transferred to the Midland Nuclear Project and progressed through various job classifications to Senior Engineer. I also participated in the initial design evaluation of the Midland Cogeneration Plant.

In July 1987, I transferred to the Market Services Department as a Senior Engineer and reached the level of Senior Market Representative. While in this department, I analyzed the economic and engineering feasibility of customer cogeneration projects.

In July 1992, I transferred to the Rates and Regulatory Affairs Department of Consumers Energy as a Principal Rate Analyst. In that capacity, I performed studies relating to all facets of development and design of Consumers Energy's gas, retail, electric and electric wholesale rates. During this period, I was heavily involved in the development of Consumers Energy's Direct Access program and in the development of Consumers Energy's Retail Open Access program. I also participated in the development of the Consumers Energy's revenue forecast.

In March 1998, I joined Nordic Energy, LLC ("Nordic"), located in Ann Arbor, Michigan, as Vice President in charge of marketing and sales. My responsibilities included all aspects of obtaining new customers and enabling Nordic to supply electricity to those customers. In May 2000, my responsibilities shifted to Operations and Regulatory Affairs. My responsibilities included management of supply purchases, transmission services, and development of new power projects. My Regulatory Affairs responsibilities included overseeing regulatory and legislation issues for the company.

In March 2003, I formed Energy Options & Solutions, based in Ann Arbor, Michigan, as a consulting concern focusing on providing engineering services and regulatory support. Through my work with Energy Options & Solutions, I gained extensive experience consulting in the areas of project development and economic analysis with renewable energy companies across the country, including: Noble Environmental Power located in Centerbrook, Connecticut; Third Planet Windpower, LLC located in Palm Beach Gardens, Florida; TradeWind Energy, LLC located in Lenexa, Kansas; Windlab Developments USA located in Canberra, Australian Capital Territory, Australia; and Matinee Energy Inc. located in Tucson, Arizona, among others.

Other examples of my consulting work have included evaluation of the Arkansas Weatherization Assistance Program for the Arkansas Energy

Office, and providing the West Michigan Prosperity Alliance with an evaluation of the business opportunities for Western Michigan businesses in the renewable energy business sector.

In 2007, I served as primary author of the report on the economic impacts of renewable portfolio standards and energy efficiency programs for the Department of Environmental Quality – State of Michigan.

In 2011, I joined KEMA, Inc. ("KEMA") located in Burlington, Massachusetts, as a Service line Leader responsible for developing its renewable energy consulting business. While at KEMA, I performed multiple renewable energy studies for the Electric Power Research Institute, including a renewable energy options study for the country of Saint Maarten (a constituent country of the Kingdom of the Netherlands). I also assisted Lake Erie Energy Development Corporation in its successful application to the U.S. Department of Energy for a multi-million dollar grant to develop an offshore wind project in Lake Erie.

In 2013, I joined CLEAResult located in Little Rock, Arkansas, as Director of Operations. My primary responsibility involved supporting program operations in assisting the company's Arkansas unit to successfully meet a 400% increase in energy efficiency goals that it managed for Entergy. I was also responsible for managing the company's natural gas energy efficiency programs in the State of Oklahoma.

In 2015, I joined the Georgia office of GDS Associates, Inc., a consulting group focusing on utility engineering and consulting services, as Managing Director in its Generation Services area.

A copy of my Curriculum Vitae is attached hereto and incorporated herein as Staff Exhibit-1.

Q. Do you have any professional registrations?

A. Yes, I am a registered Professional Engineer in Michigan and hold a LEED Green Associate credential from the U.S. Green Building Council.

Q. Have you published any papers?

A. Yes, I have authored the following publications:

- Engineering and Economic Evaluation of Offshore Wind Plant Performance and Cost Data, 2011, Produced for the Electric Power Research Institute, KEMA, Inc.
- Island of Saint Maarten Sustainable Energy Study, 2012, Produced for the Cabinet of Ministry VROMI, KEMA Inc.
- A Study of Economic Impacts from the Implementation of a Renewable Portfolio Standard and an Energy Efficiency Program in Michigan, 2007, Produced for the Michigan Department of Environmental Quality
- Alternative and Renewable Energy Cluster Analysis, 2007, Produced for the West Michigan Strategic Alliance and The Right Place

Q. Have you testified in any other regulatory proceedings?

A. Yes, I have testified before the Michigan Public Service Commission on multiple occasions as a representative of Consumers Energy, and on behalf of Energy Michigan.

Attached hereto and incorporated herein as Staff Exhibit-2, is a list of proceedings detailing my prior participation as a testifying witness before the Michigan Public Service Commission.

TESTIMONY PURPOSE AND SUMMARY

Q. What is the purpose of your testimony?

A. The North Dakota Public Service Commission ("Commission") hired GDS Associates, Inc. ("GDS") to provide an analysis and recommendation concerning Northern States Power's ("NSP") need for additional generation resources. My testimony will cover four main areas including review of NSP's Integrated Resource Plans ("IRP"), the need for additional generation resources, the cost impact on North Dakota customers of the 345 MW Power Purchase Agreement with Mankato Energy Center, LLC ("Mankato PPA") and an assessment of capacity risks.

Q. Please describe the proposed generation resource NSP is procuring through the Mankato PPA.

A. The Mankato Energy Center is located in Mankato, Minnesota. Calpine's 345 MW combined cycle ("CC") unit will be located on the same site as the existing Mankato Energy Center CC unit. NSP currently has a PPA with Calpine for 360 MW of capacity from the existing Mankato project. NSP has entered into a new 20 year PPA with a dollars per kW-month price for capacity and dollars per MWH price for energy that escalate annually after the first year of operation. All fuel used by the new unit will be procured, delivered and paid for by NSP.

Q. Please summarize your testimony.

A. Based upon NSP's 2015 IRP filed in case PU-15-019 on January 5, 2015 and information provided by NSP in response to Data Requests, NSP does not need to add any generation resources prior to 2025. NSP uses as its justification for the Mankato PPA, an outdated Fall 2011 Forecast which was not updated for known conditions and fails to include the current Midwest ISO ("MISO") reserve margin calculation methodology for determining capacity obligations. Using current NSP generation supply resource information and using the current calculations for NSP's MISO capacity obligation, indicates NSP will have at least 149 MW of excess capacity over and above reserve requirements through 2024. The addition of Mankato PPA prior to NSP's need for capacity in 2025 is likely to cost NSP's North Dakota ratepayers over $12.9 million over the 2019-2024 period. Therefore, the risks and costs associated with the Mankato PPA appear to place an unnecessary burden on North Dakota's electric ratepayers and should not be approved by the Commission.

Q. How is your testimony organized?

A. I have organized my testimony into the following sections:

1. **Forecasts and Integrated Resource Plan Review** – Review and analysis of the IRP and forecast data presented in this case. Provides the basis for using NSP's Upper Midwest Resource Plan 2016-2030, filed in North Dakota, Case No. PU-15-19.
2. **2019 - 2024 Capacity Obligations** – Analysis of NSP's generation resource needs based upon the 2015 IRP, focusing on 2019-2024 period in which NSP's capacity needs are in question.
3. **North Dakota Ratepayers Cost Impact** – Analysis of cost impact on NSP's ratepayers in North Dakota.
4. **Capacity Risks** – Assessment of the comparative risks of adding new or of not adding capacity as proposed by NSP.
5. **Conclusions** – Summary of testimony and recommendations.

Q. Have you prepared any Exhibits?

A. Yes, the following is a list of Exhibits included with my testimony:

EXHIBIT	DESCRIPTION
1.	Richard A. Polich Curriculum Vitae
2.	Regulatory Proceedings Testimony List
3.	NSP Response to Data Request 2-1
4.	NSP Response to Data Request 2-3

5. NSP Load Forecasts Adjusted for Current MISO Reserve Margin Calculation Method
6. NSP Response to Data Request 2-4
7. NSP Response to Data Request 2-11
8. NSP Response to Data Request 1-1

NSP FORECAST AND IRP REVIEW

Q. Which NSP forecasts and IRP versions did you review?

A. I reviewed portions of all of the forecasts referenced in the testimony of NSP witnesses and provided in Data Request 2-1 (Staff Exhibit 3). On page 7 of the application and on page 2, line 20 of NSP witness Kurtis J. Haeger's testimony, it states the Fall 2011 Forecast is the basis for identifying NSP's need for capacity to be filled by the Mankato project. On page 5, lines 5-8 of his testimony, Mr. Haeger refers to a spring 2012 forecast, fall 2012 forecast, spring 2013 forecast, fall 2014 forecast and 2015 Resource Plan forecast. In addition, Mr. Paul B. Johnson's testimony introduces additional capacity need forecasts.

Q. Which forecast or IRP did NSP use as the basis for identifying the capacity obligation in this Docket?

A. As stated on page 7 of NSP's Application and discussed in Mr. Haeger's testimony on page 2, lines 20 – 21, NSP's capacity obligation is based upon the Fall 2011 forecast ("Fall 2011 Forecast") which was an update of NSP's 2010 Integrated Resource Plan.

Q. Is the Fall 2011 Forecast the appropriate forecast to use for determining NSP's current forecasted capacity obligation?

A. No, in my experience in assessing utility capacity requirements, the most recent forecast should be used for determining the amount of generation capacity needed to meet load requirements. This is especially true in markets with load changes that are being caused by economic conditions and changes in consumer behaviors. Other factors, such as changes in Midwest ISO ("MISO") rules, government regulation such as the Clean Power Plan, state regulatory agency rejection of resources additions, and market factors such as the declining cost of solar energy, need to be factored into the power supply planning forecast. The outdated Fall 2011 Forecast should not be used as a basis to determine NSP's need for additional capacity. As I will show in my testimony, the Fall 2011 Forecast contains outdated information and load forecast calculation methods. NSP has acknowledged that several updated forecasts, including a new integrated resource plan, have been completed since the Fall 2011 Forecast.

Q. Have you performed a comparison of the various forecasts?

A. Yes. I have reviewed the various forecasts presented and used by NSP in this case. In response to Data Request 2-1, NSP (Staff Exhibit 3) provided the data from the various forecasts and integrated resource plans referenced in Mr. Haeger's testimony. My review of these forecasts revealed that NSP did not use the same reserve margin requirements and has applied different correction factors to adjust to MISO coincident peaks in determining capacity requirements. Data Request 2-3 (Exhibit 4) indicates that MISO has changed its Planning Reserve Margin ("PRM") several times since the 2010 IRP. MISO currently applies the PRM to 95% of NSP's peak capacity ("Coincident Peak Factor"). NSP's forecasts though 2014 do not include the current MISO 7.1% PRM or the MISO 95% Coincident Peak factor.

Q. How would you adjust NSP's forecasts and IRP to be consistent?

A. To be able to compare the forecasts, it is necessary to use the current MISO capacity obligation parameters. I have updated each of the forecasts by changing the MISO PRM to 7.1% and applying the MISO Coincident Peak Factor of 95%. Applying the MISO PRM and Coincident Peak Factor to NSP's forecasts significantly changes its calculated capacity needs. For example, if the 2010 IRP is adjusted from a 12% reserve margin used in the forecast to MISO's current 7.1% reserve requirement and applying the current coincident peak factor, NSP's 2023 capacity obligation would be reduced by 1,081 MW. Staff Exhibit 5 provides the revised NSP forecasts incorporating the current MISO PRM and Coincident Peak Factor.

Q. In his testimony, did NSP witness Mr. Johnson use the current MISO reserve margin requirements?

A. Yes, Mr. Johnson did include the current MISO reserve margin calculation methodology in the 2014 Forecast and the 2015 IRP. However, the Fall 2011 Forecast does not reflect the current MISO reserve margin calculation methodology. The Fall 2011 Forecast should have been adjusted to reflect the current MISO reserve margin calculation methodology.

Q. What is the impact of the MISO reserve margin calculation methodology on capacity obligation shown in the various NSP forecasts?

A. Applying the current MISO reserve margin calculation methodology in each of the forecasts discussed in Mr. Haeger's testimony results in a reduction of NSP's capacity obligation in all the forecasts prior to 2014. The fall 2014 forecast and the 2015 IRP already used the current MISO PRM and peak capacity factor. Applying MISO's current practice to NSP's forecasts results in reduced capacity needs illustrated in Table A.

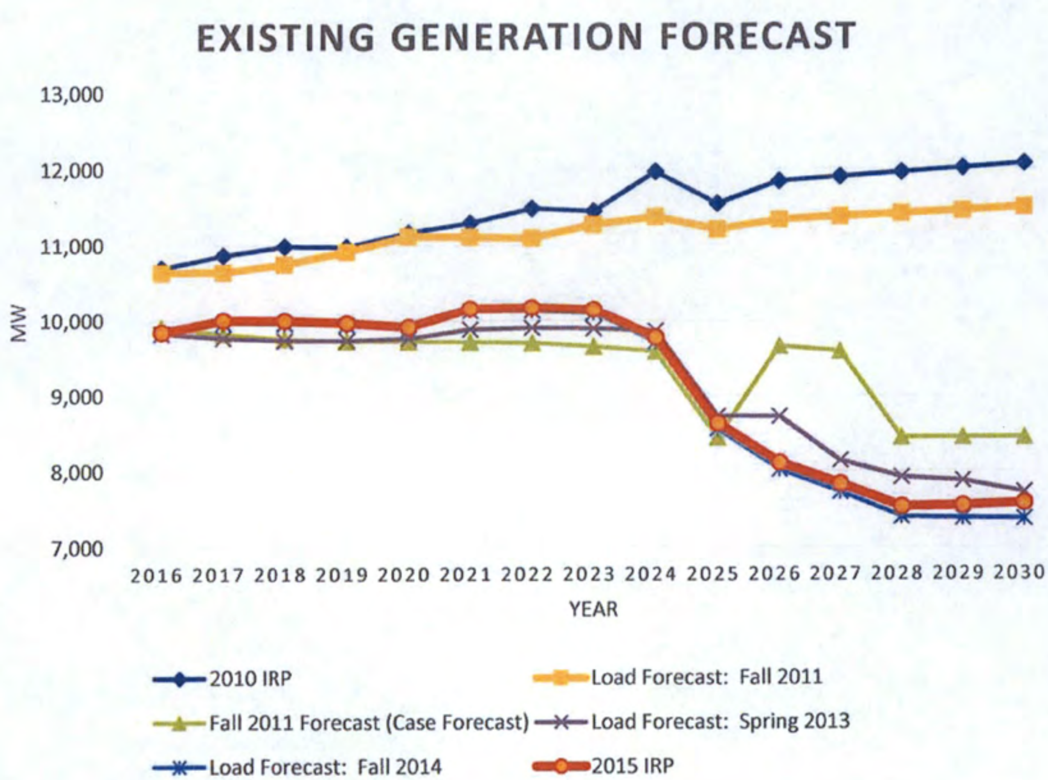
TABLE A - NSP FORECASTS DIFFERENCES IN MISO CAPACITY OBLIGATIONS

	CHANGE IN CAPACITY OBLIGATION - MW*															
NSP FORECAST	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2010 IRP Forecast	(1,012)	(1,024)	(1,034)	(1,044)	(1,052)	(1,062)	(1,068)	(1,074)	(1,081)	(1,086)	(1,090)	(1,096)	(1,101)	(1,106)	(1,111)	(1,116)
Fall 2011 Forecast	(192)	(194)	(196)	(198)	(200)	(201)	(203)	(204)	(205)	(206)	(206)	(207)	(208)	(208)	(209)	(210)
Fall 2011 Forecast 2 (Case Forecast)	(193)	(195)	(197)	(199)	(200)	(202)	(204)	(205)	(206)	(207)	(208)	(206)	(207)	(208)	(208)	(208)
Spring 2013 Forecast	(191)	(192)	(194)	(196)	(198)	(200)	(202)	(203)	(205)	(207)	(208)	(209)	(210)	(211)	(212)	(214)
Fall 2014 Forecast	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2015 IRP Forecast		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

* Changes in capacity obligation resulting from use of MISO reserve margin calcualtion methodology

Q. Are there other reasons for using the 2015 IRP as the basis for capacity need?

A. Yes. As can be seen in the following chart, NSP has updated its existing generation <u>resources</u> in each of the forecasts. This chart shows a wide variation in the amount of exisiting generation resources NSP expects to have available to meet its MISO capacity obligations. For example, in 2023, the Fall 2011 Forecast (Case Forecast) amount of existing generation resources are 496 MW (4.9%) ***<u>LOWER</u>*** than the 2015 IRP. Differences in forecasts of existing NSP generation resources are critical in determining the need for additional capacity and provide another key reason why the most recent forecast should be used.



Q. Does Table 2 on page 10 of Mr. Johnson's testimony use the most current forecast of MISO capacity obligation and NSP's available generation resources?

A. No. Response to Data Request 2-4 (Staff Exhibit 6), Attachment A, page 4 of 5 contains a table showing the calculations used to produce Mr. Johnson's Tables 2 and 3. The calculations of NSP's MISO capacity obligation in the supporting documents are different from those used in other NSP forecasts. The calculation in Staff Exhibit 5 produce MISO capacity obligations and NSP resource positions that are different from other NSP forecasts. For example, the 2016 MISO obligation used in Mr. Johnson's Table 2 shows the need for 8,572 MW while the Fall 2011 Forecast shows a need of 9,855 (Staff Exhibit 3) and the 2015 IRP shows the need for 9,691 MW. There are other differences in the amount of load management and existing resources that affect the forecasted long/short capacity needs contained in Table 2 of Mr. Johnson's testimony. Table B provides a comparison of the long/short capacity forecast used in Mr. Johnson's Table 2, the Fall 2011 Forecast, the 2015 IRP prior to adding new generation resources and the 2015 IRP with additional resources already approved. In summary, the calcualtions used by Mr. Johnson to produce his Tables 2 & 3 are inconsistent with other NSP forecast

TABLE B - Comparsion of NSP Forecast Long/(Short) Positions

NSP FORECAST	LONG/(SHORT) Position (MW) 2019	2020	2021	2022	2023	2024
Mr. Johnson's Testimony Table 2	8	0	231	182	163	(234)
Fall 2011 Forecast 2 (Case Forecast)*	(244)	(330)	(422)	(503)	(604)	(713)
2015 IRP Forecast**	152	71	301	252	232	(165)
2015 IRP Adjusted Forecast***	433	376	616	567	546	149

* Changes in NSP Forecast Long/(Short) Position resulting from use of MISO reserve margin calculation methodology

** 2015 IRP Adjusted Forecast Long/(short) position prior to adding additional generation resources

*** 2015 IRP Adjusted Forecast includes additional resources in 2015 IRP except Mankato & Geronimo.

calcualtions and should not be used as a basis for determining NSP's capacity needs.

Q. Based upon your assessment of the various NSP forecasts and projections of NSP capacity needs in Mr. Haeger's and Mr. Johnson's testimony, which forecast should the Commission base its decision on NSP's need for additional capacity for the period of 2019-2024?

A. The Commission should base its decision in this case on the most recent NSP forecast, NSP's 2015 IRP. The Fall 2011 Forecast used by NSP, is outdated and contains calculations which are not consistent with current MISO capacity obligation calculations. The 2015 IRP contains NSP's most up-to-date assessment of its loads, generation capability of current resources, known market conditions, load management capability and includes current MISO calculation methods for determining capacity obligation.

Q. Would you make any adjustments to NSP's forecasted generation resource additions contained in NSP's 2015 IRP?

A. Yes, to reflect current Commission decisions, I adjusted the 2015 IRP Forecast to delete the Calpine MEC2 and the Geronimo capacity additions from the Resource Additions section. I left Black Dog 6 in the Resource Additions since this project has been granted an Advanced Determination of Prudence by the Commission. The resulting supply forecast shown in Table C ("2015 IRP Adjusted") is the forecast I used for assessing NSP's need to add the Mankato PPA. As can be seen in the last row, NSP is forecasted to have excess generation capacity through 2024.

TABLE C - NSP 2015 IRP Forecast - Adjusted

2015 IRP Adjusted Forecast

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Peak (MW)	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798
MISO System Coincident	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
Coincident Peak (MW)	8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308
MISO Planning Reserve	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
Obligation (MW)	9,607	9,691	9,764	9,818	9,843	9,863	9,924	9,919	9,937	9,969
GENERATION RESOURCES (MW)										
Coal (MW)	2,372	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
Nuclear	1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Natural Gas	3,451	3,476	3,476	3,465	3,465	3,465	3,465	3,465	3,137	2,824
Biomass/RDF/Hydro/Wind	1,341	1,339	1,316	1,279	1,205	1,437	1,430	1,383	1,310	461
Solar	25	131	137	143	149	156	165	175	187	202
Load Management	1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103
Existing Resources	9,846	10,004	9,999	9,970	9,913	10,164	10,176	10,150	9,772	8,628
Current Position Long(Short)	239	313	235	152	71	301	252	232	(165)	(1,341)
RESOURCE ADDITIONS (MW)										
Black Dog 6	0	0	0	208	208	208	208	208	208	208
Calpine MEC2	0	0	0	0	0	0	0	0	0	0
Geronimo	0	0	0	0	0	0	0	0	0	0
Small Solar SES	(1)	(1)	0	1	3	4	4	4	4	4
Community Solar Gardens	20	36	53	72	94	103	103	102	102	101
Additional Resources	19	35	53	281	305	315	315	314	314	313
TOTAL FORECAST SUPPLY (MW)	9,865	10,039	10,052	10,251	10,218	10,479	10,491	10,464	10,086	8,941
Forecasted Position (MW)	**258**	**348**	**288**	**433**	**376**	**616**	**567**	**546**	**149**	**(1,028)**

2019-2024 CAPACITY OBLIGATION

Q. Why will the remaining portion of your testimony only focus on the time period between 2019 and 2024?

A. The remaining portion of my testimony only focuses on the time period between 2019 and 2024 because this is the period in which NSP's need for capacity is questionable and NSP does not begin to receive power under the Mankato PPA until 2019. As seen in Table C, NSP's 2015 IRP shows there is sufficient capacity up through 2024, with its first need for additional capacity in 2025.

Q. What causes the decrease in NSP's Total Forecasted Supply resources in 2024 and 2025?

A. The decrease in NSP's Total Forecast Supply resources in 2024 is due to the retirement of 33 MW of natural gas generation (Blue Lake, French Island and Granite City) and 83 MW of biomass (Bayfront and French Island). The 2025 decrease in NSP's Total Forecast Supply resources in 2025 is due to the 850 MW loss of Manitoba Hydro PPA and 358 MW Invenergy PPA (CC).

Q. Based on your analysis when would be the earliest you would recommend NSP consider adding additional generation resources?

A. Based upon NSP's 2015 IRP forecast of current MISO capacity obligation, forecasted load growth, existing generation resources and resource additions already approved, NSP should not increase generation capacity until 2025. It would not be prudent to add capacity through a 20-year PPA starting in 2019 because 30% of the PPA contract period will have expired prior to the anticipated need for capacity.

NORTH DAKOTA RATEPAYERS COST IMPACT

Q. Has NSP estimated the cost impact of the Mankato PPA on electric ratepayers?

A. Yes. On page 7, Mr. Johnson's testimony, Table 7 shows the Calpine (Mankato) Projected PPA Net Rate Impacts for the period between 2016 and 2025 on a $/kWh basis.

Q. How did NSP calculate the Calpine (Mankato) Projected PPA Net Rate Impacts?

A. Mr. Johnson's Table 7 shows NSP's estimate of the net rate impact of the Mankato PPA. NSP's projected net rate impact is calculated by comparing the estimated Mankato costs to estimated avoided costs of not using other generation resources

The net rate impact of adding the Mankato PPA is calculated by subtracting the estimated avoided fuel, O&M and purchase power costs from the estimated Mankato PPA. The resulting net costs are then divided by the 2014 forecasted NSP sales to calculate the net rate impact. The Strategist models used by NSP in performing this analysis, rely upon various assumed costs and operational input parameters.

Q. Do you feel this appropriately captures the cost impact of the Mankato PPA?

A. No. First, the base model used for calculating the Mankato PPA net cost does not include the Black Dog 6 unit. Second the projected 2019 avoided O&M costs are **[. . . . . .TRADE SECRET . . . . . .]** and average over **[. . . . . TRADE SECRET . . . .]** over the life of the contract. These amounts are more than significantly higher than the variable O&M costs used in the Strategist model for potential generation resources (response to Data Request 1-1, Staff Exhibit 8). Third, the calculated avoided energy costs with the Mankato **[TRADE SECRET DATA BEGINS ....TRADE SECRET DATA ENDS]** in the Strategist model inputs for potential generation resources.

Q. Why should the base model for comparing the impact of the Mankato PPA include Black Dog 6?

A. Both the Commission and the Minnesota Public Utilities Commission have approved the Black Dog 6 project. Thus, NSP should have included Black Dog 6 as part of the base model to be used for calculating the impacts of all other potential generation resources.

Q. What is the net cost impact of Mankato PPA when Black Dog 6 is included as part of the generation mix?

A. NSP provided data in response to Data Request 2-1 that contains sufficient information to approximate the net cost of Mankato PPA with Black Dog 6 included in NSP's generation resources. It needs to be noted that this comparison includes the high variable O&M avoided cost and energy avoided cost estimates included in NSP's calculations. With this in mind, Table D, row 1 shows the cost savings of adding Black Dog 6 to NSP's generation resource mix. The second row shows NSP's calculated net rate impact of adding both Black Dog 6 and Mankato PPA. The third row of Table D, shows the net rate difference of Rows 1 and 2. The net rate difference times the annual sales in Row 4 results in annual cost/(savings). The Total 2019-2024 cost increase to NSP ratepayers is projected to be over $39.7 million during the period in which NSP does not need capacity.

TABLE D - NORTH DAKOTA RATEPAYER COST IMPACTS OF MANKATO PPA

	NET RATE COST/(SAVINGS)					
	2019	**2020**	**2021**	**2022**	**2023**	**2024**
Base Case with Black Dog 6 ($/MWh)	($0.07)	$0.05	($0.04)	($0.06)	($0.10)	($0.11)
Base Case with Black Dog 6 & Mankato PPA ($/MWh	($0.21)	$0.18	$0.29	$0.19	$0.09	$0.06
NET RATE DIFFERENCE ($/MWh)	**($0.14)**	**$0.13**	**$0.33**	**$0.25**	**$0.18**	**$0.17**
Fall 2014 Sales Forecast, MWh	42,708,090	42,860,052	42,822,135	43,003,977	42,974,865	43,131,691
ANNUAL COST/(SAVINGS) OF MANKATO PPA	**($5,940,980)**	**$5,591,460**	**$14,153,853**	**$10,633,093**	**$7,874,467**	**$7,450,983**

TOTAL 2019-2024 COST/(SAVINGS) **$39,762,876**

Q. Why do you feel the calculated O&M avoided costs are too high?

A. Adding the Mankato PPA to NSP generation resources reduces generation from other generation resources or power purchased from MISO. Reduced MISO power purchases will not avoid any variable O&M costs. The Mankato PPA will not result in any NSP generation plants being retired in the next six years, so NSP will still incur the fixed O&M costs of those units. The only O&M costs avoided as a result of the Mankato PPA will be variable O&M costs. In response to Data Request 1-1, NSP provided the expected variable O&M costs for various types of generation resources and the highest variable O&M cost was for a coal unit, with the projected 2019 [.........**TRADE SECRET DATA** ....]. It is more than likely the Mankato PPA will result in reduced generation of natural gas simple cycle or combined cycle generation resources, and the data input into the Strategist model show the projected 2019 variable O&M costs for these type of [**TRADE SECRET DATA BEGINS** ....**TRADE SECRET DATA ENDS**] included in the calculations that produced Table 7 of Mr. Johnson's testimony.

Q. Why are NSP's avoided energy costs too high?

A. Adding the Mankato PPA to NSP generation resources has the potential to reduce generation from other power generation units or reduce purchases from MISO. The avoided energy costs typically include fuel and purchase power costs and maybe variable costs associated with reagents used in the power plant. The modeling data provided by NSP in response to Data Request 1-1 indicate the highest energy costs to be in the range [. . . . . **TRADE SECRET DATA** . . . .]. The data used to calculate the figure in Table 7 of Mr. Johnson's testimony indicate the avoided 2019 energy costs with the Mankato PPA **[**. . . . .**TRADE SECRET DATA**. . . . .**]** expensive optional generation source.

Q. Did you find any other inconsistencies in the modeling data used to produce Table 7 of Mr. Johnson's testimony?

A. The data provided in response to Data Request 2-11 indicates the Mankato PPA is only in operation for half of the year in 2019. This is based upon comparing the production in 2019 versus 2020 and subsequent years. The avoided costs used to calculate Table 7 of Mr. Johnson's testimony should be consistent. Therefore, the avoided cost estimate should be adjusted to reflect expected production in 2019.

Q. Have you adjusted for these concerns and estimated the cost associated with adding Mankato?

A. Yes. I have calculated the additional costs due to adjusting NSP's estimated avoided costs to be $206.9 million as shown in Table E.

TABLE E - AVOIDED COST REDUCTION OF MANKATO PPA

	2019	2020	2021	2022	2023	2024
Variable O&M Avoided Cost Reduction ($/MWh)	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00
Energy Avoided Cost Reduction ($/MWh)	$11.00	$11.00	$11.00	$11.00	$11.00	$11.00
Black Dog 6 & Mankato PPA Annual MWh	420,808.86	792,547.21	847,304.97	758,543.90	658,041.13	580,480.47
Additional Cost of Mankato PPA	**$21,461,252**	**$40,419,908**	**$43,212,554**	**$38,685,739**	**$33,560,098**	**$29,604,504**

TOTAL 2019-2024 COST/(SAVINGS) $206,944,054

Q. What is the potential total cost impact of the Mankato PPA?

A. The potential total cost impact on NSP ratepayers of the Mankato PPA would be obtained by adding the results of Table D and Table E or an increase of over $246.6 million during the 2019-2024 period.

Q. Have you calculated the net cost to North Dakota electric ratepayers for the period between 2019 - 2024?

A. Yes. In Tables F, I show the net cost to North Dakota electric ratepayers of over $12.9 million during the period of 2019 – 2024

TABLE F - NORTH DAKOTA RATEPAYER COSTS OF MANKATO PPA

	2019	2020	2021	2022	2023	2024
ANNUAL COST/(SAVINGS) OF MANKATO PPA(Table D)	($5,940,980)	5591460.244	14153853.14	10633093.12	7874466.933	7450982.541
Additional Cost of Mankato PPA(Table E)	$21,461,252	$40,419,908	$43,212,554	$38,685,739	$33,560,098	$29,604,504
TOTAL ANNUAL COST INCREASE	$15,520,273	$46,011,368	$57,366,407	$49,318,832	$41,434,565	$37,055,486
North Dakota Percentage of Load *	5.09%	5.15%	5.21%	5.24%	5.37%	5.41%
North Dakota Ratepayer Proportional Cost	**$789,982**	**$2,369,585**	**$2,988,790**	**$2,584,307**	**$2,225,036**	**$2,004,702**

North Dakota Ratepayer 2019-2024 Proportional Cost $12,962,402

CAPACITY RISK

Q. Is the Mankato PPA a high capacity risk option?

A. Yes. Entering into an agreement for capacity almost ten years in advance of the need for capacity presents more risk than waiting to see what occurs in the market. As discussed in the previous section, adding unneeded capacity can result in ratepayers incurring unnecessary fixed O&M and capacity charges. These costs will be incurred under the PPA terms regardless of the amount of power being supplied by the Mankato project. The risks associated with this PPA are larger because the PPA will be in place for almost six years before NSP needs the capacity. If forecasted load growth is lower than expected due to increased energy efficiency or greater utilization of distributed generation, then North Dakota electric ratepayers will be paying the fixed O&M and capacity costs unnecessarily for an even longer period.

Q. Are there fuel risks associated with this PPA?

A. Yes. NSP has contracted to supply and pay all fuel costs for the project, making it essentially a tolling agreement. The US has seen a lot of volatility of natural gas prices over the last 20 years. Recent regulations regarding CO_2 emissions is likely to increase the amount of natural gas-fired generation, which may drive natural gas prices upward. Over the next ten years, natural gas prices could experience major price swings and cause NSP ratepayers to potentially incur higher costs than those projected by NSP. Again, approving the Mankato PPA this far in advance of NSP's need for capacity has significant risk.

Q. Are there technology risks associated with approving the PPA at this time?

A. Yes, this can be seen in the advancement in efficiency of combustion turbines and combined cycle units over the last ten years. Wind turbine prices and efficiencies have also improved significantly over the last ten years. Solar systems are experiencing declining costs and increasing efficiency at a rapid rate. Approving the Mankato PPA locks in the current technology and deprives North Dakota electric ratepayers the opportunity to take advantage of technology improvements over the next ten years. This is an unnecessary risk because NSP does not need additional capacity until 2025.

CONCLUSION

Q. Based upon your review, what are your conclusions?

A. NSP's basis of its need for additional capacity is the Fall 2011 Forecast (Page 7 of application), which is outdated. NSP Witnesses, Mr. Haeger and Mr. Johnson discuss additional forecasts which do not contain the most current NSP up-to-date assessment of its loads, generation capability of current resources, known market conditions, load management capability or current MISO calculation methods for determining capacity obligation. The 2015 IRP should be used as the basis for determining NSP's need for additional capacity. The 2015 IRP shows that the earliest need for additional capacity is 2025 and adding Mankato PPA prior to 2025 will likely cost North Dakota ratepayers over $12.9 million. Therefore, I recommend the North Dakota Public Service Commission deny NSP's request for Advanced Determination of Prudence.

Q. What other conclusions have you reached?

A. Upon review of this case, I have come to the following additional conclusions:

1. NSP does not need additional capacity until 2025 and is long at least 148 MW up through 2024.
2. The calculations of net rate impact of adding the Mankato PPA should have included Black Dog 6.
3. NSP appears to have overestimated the avoided costs of adding Mankato PPA.
4. NSP has underestimated the impact of adding the Mankato PPA to its generation resource mix.
5. Adding unneeded generation resources six years prior to the need for capacity has unnecessary risks.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company **Case No. PU-15-96**
Advance Prudence – 345 MW Mankato Energy Center

STATE OF GEORGIA)
) ss.
COUNTY OF ______________)

Richard Polich, being first duly sworn on oath, deposes and states that he has read the testimony and exhibits submitted in the above captioned matter under his name, that they were prepared by him or under his direction, that he knows the contents thereof, and that the same are true and correct to the best of his knowledge and belief.

Richard Polich

Subscribed and sworn to before me this 31 day of August, 2015.

FAYE H. CULPEPPER NOTARY EXPIRES GEORGIA MARCH 3, 2018 PUBLIC COBB COUNTY

Notary Public
My Commission Expires: March 3, 2018

GDS Associates, Inc
ENGINEERS & CONSULTANTS

RICHARD A. POLICH, P.E.

Managing Director

EDUCATION

Master of Business Administration, University of Michigan, 1990
Bachelor of Science, Mechanical Engineering, University of Michigan, 1979
Bachelor of Science, Nuclear Engineering, University of Michigan, 1979

ENGINEERING REGISTRATION

Professional Engineer in the State of Michigan

PROFESSIONAL MEMBERSHIP

National Society of Professional Engineers
American Nuclear Society
American Society of Mechanical Engineers
Association of Energy Engineers Senior Member

PROFESSIONAL EXPERIENCE

Mr. Polich has more than 30 years' experience as an energy industry engineer, manager, and leader, combining his business and technical expertise in the management of governmental, industrial and utility projects. He has worked extensively in nuclear, coal, IGCC, natural gas, green/renewable generation. Mr. Polich has developed generation projects in wind, solar, and biomass in Australia, Canada, Caribbean, South American and United States locales. His generation experience includes engineering of systems and providing engineering support of plant operations. Notable projects include the Midland Nuclear Project and its conversion to natural gas combined cycle, start-up testing support for Consumers' coal-fired Campbell 3, Palisades nuclear steam generator replacement support, Covert Generating Station feasibility evaluation, and a Lake Erie offshore wind project. He also has extensive experience in utility rates and regulation, having managed Consumers Energy's rates group for a number of years. In that function his responsibilities included load and revenue forecasting, overseeing the design of gas and electric rates and testifying in regulatory proceedings. Mr. Polich has testified in over thirty regulatory and legislative proceedings.

Mr. Polich has testified in over 30 regulatory proceedings on a variety of issues. Over 15 years' experience working with Michigan Public Service Commission on renewable energy policies, independent power supplier regulations, and electric rate cases. He has also worked with the Michigan Legislature: defined laws for open markets, renewable portfolio standards. Mr. Polich has worked on various projects and policies in Arizona, Arkansas, California, Georgia, Indiana, Minnesota Nebraska, New Mexico, Ohio, Texas, and Wisconsin Commissions over the last ten years. Mr. Polich also established Consumers Energy's Federal Energy regulatory Commission transmission tariffs

SPECIFIC PROJECT EXPERIENCE

NATURAL GAS COMBINED CYCLE EXPERIENCE

Consumers Energy – 1,560 MW Midland Cogeneration Venture
Member of a small team selected to investigate the feasibility of converting the mothballed Midland Nuclear Plant into a fossil fueled power plant. Established new plant configuration that repowered the existing nuclear steam turbine with natural gas fired combustion turbines and heat recovery steam generators. Developed the new thermal cycle and heat rate, determined how to supply steam to Dow chemical for cogeneration, developed models for projecting plant performance, defined which portions of the nuclear plant were useful in the new combined cycle plant and forecasted project economics.

EXHIBIT
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Nordic Energy – (2) 1,150 MW IGCC Projects

Project Manager for the development of two IGCC projects proposed to Georgia Power and Xcel Energy in response to RFPs. Responsibilities included establishing thermal cycles, equipment selection, site selection, supervising engineering, developing project proforma and proposals.

Nordic Energy – 230 MW Power Barge

This unit was to be located on the Columbia River near Portland Oregon. Lead the project development team responsible for securing equipment, designing the power plant, design of barges, assessing site feasibility, developing project economics and interconnection applications.

Teekay Corporation – Gas to Wires Project

Feasibility study for the development of ship mounted gas turbine power units (including combined cycle) to be fueled with LNG. Performed research into power station configuration, on-ship LNG storage, LNG fuel transfer stations and project economics.

RENEWABLE ENERGY EXPERIENCE

Matinee Energy – Utility Scale Solar Developer

Engineering design and project development consultant for utility scale solar photovoltaic projects. Development activities include site selection, equipment specifications, financial analysis and preparation of proposals. Also responsible for engineering and securing electrical interconnection.

Windlab Developments USA – Wind Power Developer

Responsible for greenfield development of the US platform for wind energy projects east of the Mississippi. Developed the company's engineering protocol for wind project design and construction, responsible for managing engineering design and construction of projects, and established six wind power projects (750 MW). Responsible for negation of Power Purchase Agreements, electrical interconnection studies, interface with Midwest ISO and submitting Generation Interconnection Application.

TradeWind Energy - Wind Power Project Developer

Project developer for 800 MW of wind power projects in Michigan and Indiana. Introduced new project management methods to the development process which resulted in savings of over $200,000 annually on each project.

Third Planet Windpower – Wind Power Project Developer

Engineering and project management consultant to support the startup of new wind power company. Established engineering standards used for selection of wind project equipment and project construction, analysis tools for evaluating projecting wind project power production, and performed project economic modeling.

Noble Environmental Power – Wind Power Project Developer

Electric transmission system consultant on the development of several wind power projects. Supported Noble's decisions on transmission gird interconnect and negotiate interconnection agreements.

ENERGY EFFICIENCY EXPERIENCE

Arkansas Energy Office – Weatherization Assistance Program Evaluation

Evaluated the performance and operations of Arkansas's Weatherization Assistance Program. This included review of program effectiveness, program operations, energy efficiencies attained, adequacy of energy efficiency measures and subcontractor performance.

CLEAResult – Arkansas Energy Efficiency Programs

Energy efficiency operations and program support for 400% increase in Arkansas energy efficiency programs. Developed processes for data collection, field staff deployment and job assignments.

ECONOMIC IMPACT ASSESSMENT

Michigan Department of Environmental Quality - Economic Impacts of a Renewable Portfolio Standard and Energy Efficiency Program for Michigan

Project Manager for this report which focused on the economic impact of renewable portfolio standard and energy efficiency programs on the State of Michigan. The evaluation sued in this report encompassed using integrated resource planning models, econometric modeling and electric pricing models for the entire State of Michigan.

West Michigan Business Alliance - Alternative and Renewable Energy Cluster Analysis

Prepared the report provided a road map for Western Michigan businesses to establish new business in the renewable energy industry.

POWER PURCHASING AND TRADING

Nordic Energy LLC - Vice President

Established an innovative energy trading floor, created customer metering and billing systems that enabled Nordic to be the first non-utility company to supply electricity to retail customers in Michigan.

RATES & REGULATORY

Consumers Energy - Supervisor of Pricing and Forecasting

Managed the group responsible for setting and obtaining regulatory approval for the company's electric and gas rates. Developed new approaches to electric and natural gas competitive pricing, redesigned electric rates to simplify rates and eliminate losses and defined new strategies for customer energy pricing. Negotiated new electric supply contracts with key industrial electric customers resulting in over $800M in annual revenue.

EOS Energy Options & Solutions – Consulting Company

Provided testimony for multiple clients in both Detroit Edison and Consumers Energy in over 30 regulatory proceedings. Testimony topics included rates, public policy and deregulation. Also testified in several legislative proceedings in both Michigan and Ohio, addressing energy policy. Provided expert witness testimony in Massachusetts regarding wind energy projects.

POWER PROJECT EXPERIENCE:

Detroit Edison St Clair Power Station – Performed coal combustion analysis associated with conversion Powder River Basin coal. Work included pulverizer mill performance testing, boiler combustion analysis on new coal, and unit performance analysis.

Consumers Energy Campbell 3 - Supported start-up efforts of this 800 MW pulverized coal power plant. Part of team that performed analysis of boiler data and determined the cause of superheater failure. Also part of team to analyze performance test data for warranty evaluation.

Consumers Energy Weadock Plant – Design oversight and specified various plant upgrades during major maintenance outage. Included replacement of high pressure superheater, design of new steam supply pipes, valve specifications and supported plant restart.

Consumers Energy Midland Nuclear Plant – Responsible for overseeing EPC contractor design and construction of primary and secondary nuclear systems. Included review of systems for compliance with Nuclear Regulatory Commission regulations. Key projects included:

- Leading team to analyze plant and determine best methods for compliance with new CFR Appendix R Fire Protection rules
- Design of primary cooling system pump oil collection and disposal systems.
- Oversight of redesign of component cooling water systems.
- Analysis of diesel generator capability to meet emergency shutdown power requirements.
- Primary interface with Dow Chemical for steam supply contract.

Consumers Energy Midland Cogeneration Venture – Part of team to assess and develop design for converting nuclear plant to gas combined cycle project. This included researching and developing scenarios for project funding and regulatory approach Primary responsibilities included:

- Developing new thermal cycle that best utilized existing steam turbine and supply steam to Dow Chemical.
- Determining which existing assets could be utilized in new plant and determining the original construction value of these assets.

REGULATORY AND LEGISLATIVE EXPERIENCE

Consumers Energy Manager of Rates – Responsible for managing rate design team, forecasting annual sales and revenue forecast and developing regulatory strategies. Testified in several state and federal regulatory proceedings.

PAPERS & PUBLICATIONS

Engineering and Economic Evaluation of Offshore Wind Plant Performance and Cost Data, 2011, Produced for the Electric Power Research Institute, KEMA, Inc.

FERC's 15% Fast Track Screening Criterion, 2012, Paper reviewing the FERC 15% screening criteria for electrical interconnection, KEMA, Inc.

Island of Saint Maarten Sustainable Energy Study, 2012, Produced for the Cabinet of Ministry VROMI, KEMA Inc.

A Study of Economic Impacts from the Implementation of a Renewable Portfolio Standard and an Energy Efficiency Program in Michigan, 2007, Produced for the Michigan Department of Environmental Quality

Alternative and Renewable Energy Cluster Analysis, 2007, Produced for the West Michigan Strategic Alliance and The Right Place

COURSES & SEMINARS

Association of Energy Engineers – Certified Energy Manager
Green Building Council – Associated LEED Certification Training
CLEAResult Leadership Academy

COMMUNITY SERVICE AND ACTIVITIES

Bicycling, hiking and cross-country skiing
Instrument-Rated Private Pilot
Habitat for Humanity
Scoutmaster
Soccer coach and referee
Volunteer work for disaster relief and building homes in Mexico

PREVIOUS TESTIMONY OF RICHARD A. POLICH

CASE	ON BEHALF	TITLE
U-10143	Consumers Energy	Consumers Energy Approval of an Experimental Retail Wheeling Case
U-10335	Consumers Energy	General Rate Case
U-10625	Consumers Energy	Proposal for Market-Based Rates Under Rate-K
U-10685	Consumers Energy	1996 General Rate Case
U-11915	Energy Michigan	Supplier Licensing
U-11955	Energy Michigan	Consumers Energy Stranded & Implementation Cost Recovery
U-11956	Energy Michigan	Detroit Edison Stranded & Implementation Cost Recovery
U-12478	Energy Michigan	Detroit Edison Asset Securitization Case
U-12488	Energy Michigan	Consumers Energy Retail Open Access Tariff
U-12489	Energy Michigan	Detroit Edison Retail Open Access Tariffs
U-12505	Energy Michigan	Consumers Energy Asset Securitization Cases
U-12639	Energy Michigan	Stranded Cost Methodology Case
U-13380	Energy Michigan	Consumers Energy 2000, 2001 & 2002 Stranded Cost Case
U-13350	Energy Michigan	Detroit Edison 2000 & 2001 Stranded Cost Case
U-13715	Energy Michigan	Consumers Energy Securitization of Qualified Costs
U-13720	Energy Michigan	Consumers Energy 2002 Stranded Costs
U-13808	Energy Michigan	Detroit Edison General Rate Case
U-13808-R	Energy Michigan	Detroit Edison 2004 Stranded Cost &
U-14474	Energy Michigan	Detroit Edison 2004 PSCR Reconciliation Case
U-13933	Energy Michigan	Detroit Edison Low-Income Energy Assistance Credit for Residential Electric Customers
U-13917-R	Energy Michigan	Consumers Energy 2004 PSCR Reconciliation Case
U-13989	Energy Michigan	Consumers Energy Request for Special Contract Approval
U-14098	Energy Michigan	Consumers Energy 2003 Stranded Costs
U-14148	Energy Michigan	Consumers Energy MCL 460.10d(4) Case
U-14347	Energy Michigan	Consumers Energy General Rate Case
U-14274-R	Energy Michigan	Consumers Energy 2005 PSCR Reconciliation Case
U-14275-R	Energy Michigan	Detroit Edison Company 2005 PSCR Reconciliation Case
U-14399	Energy Michigan	Detroit Edison Company Application for Unbundling of Rate
U-14992	Energy Michigan	Power Purchase Agreement and for Other Relief in Connection with the sale of the Palisades Nuclear Power Plant and Other Assets

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☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Case No.:	PU-15-96		
Response To:	ND Public Service Advocacy Staff	Data Request No.	2-1
Requestor:	Richard A. Polich		
Date Received:	July 31, 2015		

Question:

On page 2, line 20 of Mr. Haeger's testimony, he refers to a fall 2011 forecast as being the basis of identifying the capacity need to be filled with the Mankato project. On page 5, lines 5- 8, Mr. Haeger's testimony refers to spring 2012, fall 2012, spring 2013, fall 2014 and 2015 Resource Plan forecasts. Please provide for each of these forecasts the data provided in Table 1 on page 6 of Paul B. Johnson's testimony for each year through 2030. Please provide this data in an Excel spreadsheet.

Response:

Table 1 requires a Loads and Resources (L&Rs) analysis, which we do not do for every load forecast. The Company typically publishes a spring load forecast, with a fall update.

Attachment A to this response provides the L&Rs for the following forecasts:

Forecast Vintage	Docket	Initial Filing
Spring 2010	2011-2025 Resource Plan (August 2010)	August 2010
Fall 2011	2011-2025 Resource Plan Update	December 2011
Fall 2012	Capacity Acquisition Certification of Need (CAP CON)	December 2012
Spring 2013	CAP CON Testimony	September 2013
Fall 2014	CAP CON Compliance Filing	September 2014
Fall 2014 (w/ solar update)	2016-2030 Resource Plan	March 2015

Preparer:	Mary Morrison
Title:	Resource Planning Analyst
Department:	Resource Planning and Bidding
Telephone:	612.330.5862
Date:	August 10, 2015

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Docket: 2011-2025 Upper Midwest Resource Plan
Filing Date: August 2010
Load Forecast: Spring 2010

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak	9,761	9,873	9,985	10,082	10,180	10,263	10,353	10,415	10,477	10,538	10,593	10,633	10,685	10,738	10,785	10,835	10,886
Coincident Peak																	
Reserve Margin	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%
Obligation	10,932	11,058	11,183	11,292	11,401	11,494	11,595	11,665	11,734	11,802	11,865	11,909	11,967	12,026	12,080	12,135	12,192
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	2,676	2,676	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423
Nuclear	1,742	1,742	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	2,139
Gas	3,660	3,660	4,050	4,245	4,441	4,441	4,636	4,636	4,838	4,838	5,447	5,878	6,187	6,289	6,403	6,474	6,212
Wind, Hydro, Bio	1,495	1,351	1,351	1,323	1,248	1,237	1,231	1,356	1,346	1,309	1,220	368	353	309	249	234	226
Solar																	
Load Management	1,058	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067
Resources	10,631	10,495	10,703	10,869	10,990	10,979	11,168	11,293	11,485	11,448	11,969	11,547	11,841	11,900	11,953	12,009	12,066
Long (Short)	-301	-562	-481	-423	-411	-515	-427	-373	-249	-355	104	-362	-126	-126	-126	-126	-126

Docket: 2011 -2025 Resource Plan Update
Filing Date: December 2011
Load Forecast: Fall 2011

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak	9,305	9,402	9,495	9,581	9,672	9,760	9,839	9,918	9,981	10,031	10,069	10,094	10,117	10,152	10,185	10,218	10,259
Coincident Peak																	
Reserve Margin	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%
Obligation	9,658	9,759	9,855	9,944	10,039	10,130	10,212	10,294	10,360	10,411	10,451	10,476	10,500	10,536	10,571	10,605	10,648
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	2,752	2,752	2,495	2,495	2,495	2,495	2,495	2,495	2,495	2,495	2,466	2,466	2,466	2,466	2,466	2,466	2,466
Nuclear	1,657	1,712	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767
Gas	3,778	3,778	3,778	3,778	3,959	4,155	4,350	4,225	4,225	4,421	4,616	5,321	5,456	5,533	5,569	5,654	5,704
Wind, Hydro, Bio	1,522	1,356	1,357	1,356	1,284	1,257	1,266	1,390	1,382	1,364	1,305	439	434	400	405	362	361
Solar																	
Load Management	1,223	1,236	1,244	1,249	1,244	1,240	1,236	1,231	1,227	1,222	1,218	1,213	1,209	1,205	1,201	1,196	1,193
Resources	10,933	10,834	10,642	10,645	10,750	10,913	11,113	11,109	11,096	11,269	11,371	11,206	11,332	11,371	11,409	11,445	11,491
Long (Short)	1,275	1,075	787	701	711	784	902	815	736	857	921	730	832	834	837	840	843

Docket: Resource Plan Supplemental Testimony; Establish Size, Type, Timing in CAP CON Proceeding
Filing Date: December 2012
Load Forecast: Fall 2012

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak	9,328	9,428	9,524	9,613	9,708	9,799	9,881	9,963	10,029	10,082	10,123	10,151	10,082	10,123	10,151	10,151	10,151
Coincident Peak																	
Reserve Margin	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%
Obligation	9,682	9,785	9,885	9,977	10,076	10,170	10,255	10,341	10,409	10,464	10,507	10,536	10,464	10,507	10,536	10,536	10,536
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	2,663	2,423	2,331	2,331	2,331	2,331	2,331	2,331	2,331	2,331	2,320	2,320	2,331	2,320	2,320	2,320	2,320
Nuclear	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610
Gas	3,476	3,476	3,533	3,437	3,424	3,424	3,424	3,310	3,310	3,310	3,310	3,015	3,310	3,310	3,015	3,015	3,015
Wind, Hydro, Bio	1,432	1,288	1,289	1287	1238	1212	1213	1323	1313	1270	1219	372	1270	1219	372	372	372
Solar																	
Load Management	1,134	1,145	1,153	1,157	1,153	1,149	1,145	1,141	1,137	1,133	1,128	1,124	1,133	1,128	1,124	1,124	1,124
Resources	10,315	9,942	9,916	9,822	9,756	9,726	9,723	9,715	9,701	9,654	9,587	8,441	9,654	9,587	8,441	8,441	8,441
Long (Short)	633	157	31	-155	-320	-444	-532	-626	-708	-810	-920	-2,095	-810	-920	-2,095	-2,095	-2,095

Docket: CAP CON Docket Testimony
Filing Date: September 2013
Load Forecast: Spring 2013

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak	9,261	9,334	9,411	9,500	9,590	9,676	9,770	9,859	9,950	10,029	10,100	10,151	10,208	10,266	10,326	10,380	10,449
Coincident Peak																	
Reserve Margin	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%
Obligation	9,612	9,687	9,767	9,860	9,953	10,042	10,140	10,233	10,327	10,409	10,483	10,536	10,595	10,655	10,717	10,773	10,845

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	2,586	2,367	2,367	2,367	2,367	2,367	2,367	2,367	2,367	2,367	2,353	2,353	2,353	2,353	2,353	2,353	2,353
Nuclear	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623
Gas	3,460	3,460	3,517	3,427	3,416	3,416	3,416	3,302	3,302	3,302	3,302	2,992	2,992	2,428	2,194	2,194	2,033
Wind, Hydro, Bio	1,385	1,241	1,241	1,238	1,189	1,162	1,161	1,383	1,388	1,379	1,366	546	548	529	547	502	515
Solar	13	23	35	49	66	83	103	103	103	103	103	103	103	103	103	103	103
Load Management	1,033	1,042	1,051	1,063	1,074	1,085	1,096	1,106	1,118	1,120	1,116	1,111	1,106	1,102	1,098	1,094	1,090
Resources	10,099	9,757	9,835	9,768	9,735	9,735	9,766	9,884	9,901	9,895	9,863	8,728	8,725	8,138	7,918	7,869	7,717
Long (Short)	487	69	68	-93	-218	-307	-374	-349	-426	-515	-620	-1,808	-1,870	-2,517	-2,800	-2,905	-3,128

Docket: CAP CON Docket Compliance Filing
Filing Date: September 2014
Load Forecast: Fall 2014

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak	8,851	9,301	9,409	9,478	9,552	9,608	9,639	9,669	9,726	9,720	9,712	9,694	9,697	9,705	9,786	9,774	9,817
Coincident Peak	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Reserve Margin	7.4%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
Obligation	9,031	9,463	9,573	9,643	9,718	9,776	9,807	9,838	9,896	9,890	9,882	9,863	9,867	9,874	9,956	9,945	9,989

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	2,709	2,492	2,391	2,414	2,414	2,414	2,414	2,414	2,414	2,414	2,395	2,395	2,395	2,395	2,395	2,395	2,395
Nuclear	1,619	1,645	1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Gas	3,388	3,362	3,431	3,457	3,457	3,446	3,446	3,446	3,446	3,446	3,137	2,824	2,298	2,047	1,812	1,812	1,812
Wind, Hydro, Bio	1,378	1,256	1,325	1,326	1,303	1,277	1,202	1,433	1,425	1,385	1,317	471	463	421	331	314	312
Solar	8	15	24	109	115	121	127	129	128	128	127	126	125	125	124	123	122
Load Management	994	999	1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103	1,098	1,094	1,089	1,085	1,080
Resources	10,096	9,769	9,827	9,970	9,965	9,945	9,888	10,132	10,135	10,105	9,719	8,562	8,023	7,724	7,394	7,372	7,364
Long (Short)	1,066	306	254	327	246	169	81	294	239	215	-163	-1,301	-1,844	-2,151	-2,562	-2,573	-2,625

Docket: 2016-2030 Upper Midwest Resource Plan
Filing Date: March 2015
Load Forecast: Fall 2014 - update for solar

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Peak	8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
MISO Planning Reserve	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
Obligation	9,607	9,691	9,764	9,818	9,843	9,863	9,924	9,919	9,937	9,969	10,041	10,136	10,313	10,328	10,430

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	2,372	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
Nuclear	1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Natural Gas	3,451	3,476	3,476	3,465	3,465	3,465	3,465	3,465	3,137	2,824	2,298	2,047	1,812	1,812	1,812
Biomass/RDF/Hydro/Wind	1,341	1,339	1,316	1,279	1,205	1,437	1,430	1,383	1,310	461	451	407	318	300	299
Solar	25	131	137	143	149	156	165	175	187	202	221	242	269	301	339
Load Management	1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103	1,098	1,094	1,089	1,085	1,080
Existing Resources	9,846	10,004	9,999	9,970	9,913	10,164	10,176	10,150	9,772	8,628	8,106	7,827	7,526	7,536	7,569
Current Position Long(Short)	239	313	235	152	71	301	252	232	-165	-1,341	-1,935	-2,308	-2,787	-2,793	-2,861
Black Dog 6	0	0	0	208	208	208	208	208	208	208	208	208	208	208	208
Calpine MEC2	0	0	0	278	278	278	278	278	278	278	278	278	278	278	278
Geronimo/Aurora	0	0	70	69	69	69	68	68	68	67	67	67	66	66	66
Community Solar Gardens	20	36	53	72	94	103	103	102	102	101	101	100	100	99	98
Additional Resources	20	36	123	627	649	658	657	656	656	654	654	653	652	651	650
Forecasted Position	259	349	358	779	720	958	909	888	491	-686	-1,281	-1,656	-2,135	-2,142	-2,212

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Case No.:	PU-15-96		
Response To:	ND Public Service Advocacy Staff	Data Request No.	2-3
Requestor:	Richard A. Polich		
Date Received:	July 31, 2015		

Question:

In Table 1, page 6 of Mr. Johnson's testimony, the reserve margin is shown to be 3.8%. In table 1 of NSP's 2015 Resource Plan supplement, dated March 16, 2015, the MISO Planning Reserve is shown to be 7.1%. Please explain this discrepancy.

Response:

Table 1 reflects the reserve margin calculations applicable to the 2011 Resource Plan, as well as the December 2011 Resource Plan Update, which applied the MISO Planning Reserve Margin (PRM) effective at that time.

For Planning Year 2013, MISO introduced a new PRM methodology, which also applied a correction for "coincident peak." Load Serving Entity's with a system peak not coincident with MISO's peak receive a coincident factor credit.

Thus the former PRM factor was replaced with two separate factors. The table below demonstrates the overall impact of this methodology change.

Planning Year	Coincident Factor (% of NSP System Peak at time of MISO Peak)	MISO Planning Reserve Margin
PY 2010	NA	3.8%
PY 2011	NA	8.8%
PY 2012	NA	8.8%
PY 2013	95%	6.2%
PY 2014	95%	7.3%
PY 2015	95%	7.1%
PY 2016	95%	7.1%

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Establishing a PRM is an annual process. Typically the next year's value is published on November 1. In August 2014, MISO provided a forecast for future PRM trending. The data indicated the PRM is stable, and would continue to decrease by a few percentage points over the next 10 years.

Preparer:	Mary Morrison
Title:	Resource Planning Analyst
Department:	Resource Planning and Bidding
Telephone:	612.330.5862
Date:	August 10, 2015

NORTHERN STATES POWER
LOAD FORECASTS

LINE **ASSUMPTIONS:**

LINE		
1	Reserve Margin	7.1%
2	MISO Coincident Peak factor	95.0%

2010 IRP Forecast

LINE		2014	2015	(a) 2016	(b) 2017	(c) 2018	(d) 2019	(e) 2020	(f) 2021	(g) 2022	(h) 2023	(i) 2024	(j) 2025	(k) 2026	(l) 2027	(m) 2028	(n) 2029	(o) 2030
3		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
4	Peak	9,761	9,873	9,985	10,082	10,180	10,263	10,353	10,415	10,477	10,538	10,593	10,633	10,685	10,738	10,785	10,835	10,886
5	MISO Coincident Peak Factor	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
6	Reserve Margin	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
7	Obligation	9,931	10,045	10,159	10,258	10,357	10,442	10,534	10,597	10,660	10,722	10,778	10,819	10,871	10,925	10,974	11,024	11,076
8	GENERATION RESOURCES																	
9	Coal	2,676	2,676	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423	2,423
10	Nuclear	1,742	1,742	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	1,812	2,139
11	Gas	3,660	3,660	4,050	4,245	4,441	4,441	4,636	4,636	4,838	4,838	5,447	5,878	6,187	6,289	6,403	6,474	6,212
12	Wind, Hydro, Bio	1,495	1,351	1,351	1,323	1,248	1,237	1,231	1,356	1,346	1,309	1,220	368	353	309	249	234	226
13	Solar																	
14	Load Management	1,058	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067	1,067
15	Total Resources	10,631	10,495	10,703	10,869	10,990	10,979	11,168	11,293	11,485	11,448	11,969	11,547	11,841	11,900	11,953	12,009	12,066
16	**Long (Short)**	**700**	**450**	**543**	**611**	**632**	**537**	**634**	**695**	**825**	**726**	**1,190**	**728**	**969**	**975**	**980**	**985**	**990**

Fall 2011 Forecast

LINE		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
17		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
18	Peak	9,305	9,402	9,495	9,581	9,672	9,760	9,839	9,918	9,981	10,031	10,069	10,094	10,117	10,152	10,185	10,218	10,259
19	Coincident Peak	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
20	Reserve Margin	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
21	Obligation	9,468	9,566	9,661	9,748	9,841	9,930	10,010	10,091	10,155	10,206	10,245	10,270	10,293	10,329	10,363	10,396	10,438
22	GENERATION RESOURCES																	
23	Coal	2,752	2,752	2,495	2,495	2,495	2,495	2,495	2,495	2,495	2,495	2,466	2,466	2,466	2,466	2,466	2,466	2,466
24	Nuclear	1,657	1,712	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767	1,767
25	Gas	3,778	3,778	3,778	3,778	3,959	4,155	4,350	4,225	4,225	4,421	4,616	5,321	5,456	5,533	5,569	5,654	5,704
26	Wind, Hydro, Bio	1,522	1,356	1,357	1,356	1,284	1,257	1,266	1,390	1,382	1,364	1,305	439	434	400	405	362	361
27	Solar																	
28	Load Management	1,223	1,236	1,244	1,249	1,244	1,240	1,236	1,231	1,227	1,222	1,218	1,213	1,209	1,205	1,201	1,196	1,193
29	Resources	10,933	10,834	10,642	10,645	10,750	10,913	11,113	11,109	11,096	11,269	11,371	11,206	11,332	11,371	11,409	11,445	11,491
30	**Long (Short)**	**1,465**	**1,268**	**981**	**897**	**909**	**983**	**1,103**	**1,017**	**940**	**1,062**	**1,127**	**936**	**1,038**	**1,042**	**1,046**	**1,049**	**1,053**

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NORTHERN STATES POWER
LOAD FORECASTS

LINE	ASSUMPTIONS:	
1	Reserve Margin	7.1%
2	MISO Coincident Peak factor	95.0%

LINE					(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
31	Fall 2011 Forecast 2 (Case Forecast)		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
32		Peak	9,328	9,428	9,524	9,613	9,708	9,799	9,881	9,963	10,029	10,082	10,123	10,151	10,082	10,123	10,151	10,151	10,151
33		Coincident Peak	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
34		Reserve Margin	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
35		Obligation	9,491	9,593	9,690	9,781	9,877	9,970	10,053	10,137	10,204	10,258	10,300	10,328	10,258	10,300	10,328	10,328	10,328
36		GENERATION RESOURCES																	
37		Coal	2,663	2,423	2,331	2,331	2,331	2,331	2,331	2,331	2,331	2,331	2,320	2,320	2,331	2,320	2,320	2,320	2,320
38		Nuclear	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610
39		Gas	3,476	3,476	3,533	3,437	3,424	3,424	3,424	3,310	3,310	3,310	3,310	3,015	3,310	3,310	3,015	3,015	3,015
40		Wind, Hydro, Bio	1,432	1,288	1,289	1,287	1,238	1,212	1,213	1,323	1,313	1,270	1,219	372	1,270	1,219	372	372	372
41		Solar																	
42		Load Management	1,134	1,145	1,153	1,157	1,153	1,149	1,145	1,141	1,137	1,133	1,128	1,124	1,133	1,128	1,124	1,124	1,124
43		Resources	10,315	9,942	9,916	9,822	9,756	9,726	9,723	9,715	9,701	9,654	9,587	8,441	9,654	9,587	8,441	8,441	8,441
44		Long (Short)	824	349	226	41	(121)	(244)	(330)	(422)	(503)	(604)	(713)	(1,887)	(604)	(713)	(1,887)	(1,887)	(1,887)
45	Spring 2013 Forecast		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
46		Peak	9,261	9,334	9,411	9,500	9,590	9,676	9,770	9,859	9,950	10,029	10,100	10,151	10,208	10,266	10,326	10,380	10,449
47		Coincident Peak	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
48		Reserve Margin	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
49		Obligation	9,423	9,497	9,575	9,666	9,757	9,844	9,940	10,032	10,124	10,204	10,276	10,328	10,386	10,445	10,506	10,561	10,631
50		GENERATION RESOURCES																	
51		Coal	2,586	2,367	2,367	2,367	2,367	2,367	2,367	2,367	2,367	2,367	2,353	2,353	2,353	2,353	2,353	2,353	2,353
52		Nuclear	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623
53		Gas	3,460	3,460	3,517	3,427	3,416	3,416	3,416	3,302	3,302	3,302	3,302	2,992	2,992	2,428	2,194	2,194	2,033
54		Wind, Hydro, Bio	1,385	1,241	1,241	1,238	1,189	1,162	1,161	1,383	1,388	1,379	1,366	546	548	529	547	502	515
55		Solar	13	23	35	49	66	83	103	103	103	103	103	103	103	103	103	103	103
56		Load Management	1,033	1,042	1,051	1,063	1,074	1,085	1,096	1,106	1,118	1,120	1,116	1,111	1,106	1,102	1,098	1,094	1,090
57		Resources	10,099	9,757	9,835	9,768	9,735	9,735	9,766	9,884	9,901	9,895	9,863	8,728	8,725	8,138	7,918	7,869	7,717
58		Long (Short)	677	260	260	102	(22)	(109)	(174)	(147)	(223)	(310)	(413)	(1,601)	(1,661)	(2,307)	(2,589)	(2,692)	(2,914)

NORTHERN STATES POWER
LOAD FORECASTS

LINE **ASSUMPTIONS:**

LINE		
1	Reserve Margin	7.1%
2	MISO Coincident Peak factor	95.0%

LINE					(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
59	Fall 2014 Forecast		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
60		Peak	8,851	9,301	9,409	9,478	9,552	9,608	9,639	9,669	9,726	9,720	9,712	9,694	9,697	9,705	9,786	9,774	9,817
61		Coincident Peak	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
62		Reserve Margin	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
63		Obligation	9,005	9,463	9,573	9,643	9,718	9,776	9,807	9,838	9,896	9,890	9,882	9,863	9,867	9,874	9,956	9,945	9,989
64		GENERATION RESOURCES																	
65		Coal	2,709	2,492	2,391	2,414	2,414	2,414	2,414	2,414	2,414	2,414	2,395	2,395	2,395	2,395	2,395	2,395	2,395
66		Nuclear	1,619	1,645	1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
67		Gas	3,388	3,362	3,431	3,457	3,457	3,446	3,446	3,446	3,446	3,446	3,137	2,824	2,298	2,047	1,812	1,812	1,812
68		Wind, Hydro, Bio	1,378	1,256	1,325	1,326	1,303	1,277	1,202	1,433	1,425	1,385	1,317	471	463	421	331	314	312
69		Solar	8	15	24	109	115	121	127	129	128	128	127	126	125	125	124	123	122
70		Load Management	994	999	1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103	1,098	1,094	1,089	1,085	1,080
71		Resources	10,096	9,769	9,827	9,970	9,965	9,945	9,888	10,132	10,135	10,105	9,719	8,562	8,023	7,724	7,394	7,372	7,364
72		**Long (Short)**	**1,091**	**306**	**254**	**327**	**246**	**169**	**81**	**294**	**239**	**215**	**(163)**	**(1,301)**	**(1,844)**	**(2,151)**	**(2,562)**	**(2,573)**	**(2,625)**
73	2015 IRP Forecast				2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
74		Peak			9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
75		MISO System Coincident			95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
76		Coincident Peak			8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
77		MISO Planning Reserve			7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
78		Obligation	9,005	9,463	9,607	9,691	9,764	9,818	9,843	9,863	9,924	9,919	9,937	9,969	10,041	10,136	10,313	10,328	10,430
79		GENERATION RESOURCES																	
80		Coal			2,372	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
81		Nuclear			1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
82		Natural Gas			3,451	3,476	3,476	3,465	3,465	3,465	3,465	3,465	3,137	2,824	2,298	2,047	1,812	1,812	1,812
83		Biomass/RDF/Hydro/Wind			1,341	1,339	1,316	1,279	1,205	1,437	1,430	1,383	1,310	461	451	407	318	300	299
84		Solar			25	131	137	143	149	156	165	175	187	202	221	242	269	301	339
85		Load Management			1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103	1,098	1,094	1,089	1,085	1,080
86		Existing Resources	10,096	9,769	9,846	10,004	9,999	9,970	9,913	10,164	10,176	10,150	9,772	8,628	8,106	7,827	7,526	7,536	7,569
87		**Current Position Long(Short)**			**239**	**313**	**235**	**152**	**71**	**301**	**252**	**232**	**(165)**	**(1,341)**	**(1,935)**	**(2,308)**	**(2,787)**	**(2,793)**	**(2,861)**
88		Resource Additions																	
89		Black Dog 6			0	0	0	208	208	208	208	208	208	208	208	208	208	208	208
90		Calpine MEC2			0	0	0	278	278	278	278	278	278	278	278	278	278	278	278
91		Geronimo/Aurora			0	0	70	69	69	69	68	68	68	67	67	67	66	66	66
92		Small Solar SES			(1)	(1)	0	1	3	4	4	4	4	4	4	4	4	3	3
93		Community Solar Gardens			20	36	53	72	94	103	103	102	102	101	101	100	100	99	98
94		Additional Resources			19	35	123	628	652	662	661	660	660	658	658	657	656	654	653
95		**Forecasted Position**			**258**	**348**	**358**	**780**	**723**	**962**	**913**	**892**	**495**	**(682)**	**(1,277)**	**(1,652)**	**(2,131)**	**(2,139)**	**(2,209)**

NORTHERN STATES POWER
LOAD FORECASTS

LINE	ASSUMPTIONS:	
1	Reserve Margin	7.1%
2	MISO Coincident Peak factor	95.0%

2015 IRP Adjusted Forecast

LINE				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
96				2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
97	Peak			9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
98	MISO System Coincident			95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
99	Coincident Peak			8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
100	MISO Planning Reserve			7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
101	Obligation			9,607	9,691	9,764	9,818	9,843	9,863	9,924	9,919	9,937	9,969	10,041	10,136	10,313	10,328	10,430
102	GENERATION RESOURCES																	
103	Coal			2,372	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
104	Nuclear			1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
105	Natural Gas			3,451	3,476	3,476	3,465	3,465	3,465	3,465	3,465	3,137	2,824	2,298	2,047	1,812	1,812	1,812
106	Biomass/RDF/Hydro/Wind			1,341	1,339	1,316	1,279	1,205	1,437	1,430	1,383	1,310	461	451	407	318	300	299
107	Solar			25	131	137	143	149	156	165	175	187	202	221	242	269	301	339
108	Load Management			1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103	1,098	1,094	1,089	1,085	1,080
109	Existing Resources	10,096	9,769	9,846	10,004	9,999	9,970	9,913	10,164	10,176	10,150	9,772	8,628	8,106	7,827	7,526	7,536	7,569
110	Current Position Long(Short)			239	313	235	152	71	301	252	232	(165)	(1,341)	(1,935)	(2,308)	(2,787)	(2,793)	(2,861)
111	Resource Additions																	
112	Black Dog 6			0	0	0	208	208	208	208	208	208	208	208	208	208	208	208
113	Calpine MEC2			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
114	Geronimo			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
115	Small Solar SES			(1)	(1)	0	1	3	4	4	4	4	4	4	4	4	3	3
116	Community Solar Gardens			20	36	53	72	94	103	103	102	102	101	101	100	100	99	98
117	Additional Resources			19	35	53	281	305	315	315	314	314	313	313	312	312	310	309
118	TOTAL FORECAST SUPPLY	10,096	9,769	9,865	10,039	10,052	10,251	10,218	10,479	10,491	10,464	10,086	8,941	8,419	8,139	7,838	7,846	7,878
119	Forecasted Position			258	348	288	433	376	616	567	546	149	(1,028)	(1,622)	(1,996)	(2,475)	(2,483)	(2,552)

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Case No.:	PU-15-96		
Response To:	ND Public Service Advocacy Staff	Data Request No.	2-4
Requestor:	Richard A. Polich		
Date Received:	July 31, 2015		

Question:

Table 3 on page 11 of Mr. Johnson's testimony provides a 10 year forecast of NSP's North Dakota allocated system capacity. The following discovery questions refer to this table:

a. Please explain how the ND as a Percentage of NSP System shown in row 1 were calculated. Provide all data used in the calculations.
b. Please explain why the ND percentage of NSP System increases over the 10 year period.
c. Has NSP calculated the Percentage of NSP System for the period through 2030? If so, please provide the data.

Response:

a. The data used for Table 3, page 11 of Mr. Johnson's testimony is taken from our response to NDPSC Data Request No. 11 in Case No. PU-14-810. That response is included here as Attachment A.

   We note the Company plans for the NSP System on an integrated basis and does not separately analyze North Dakota load as part of its resource planning efforts. By its nature the calculation is an approximation.

b. The overall rate of growth in North Dakota has outpaced growth rates in other NSP jurisdictions, as well as other areas of the country.

> The Bismarck Tribune, February 25, 2015, *Census: North Dakota should expect continued growth.*
>
> > Iverson [Manager of the North Dakota Census Office] said he expects the state's population to reach 800,000 within the next five years. That's about 60,500 more people than live here now and about 164,000 more than what the office expected when "out-migration" was a buzzword in 2000.

EXHIBIT
6

The North Dakota census values indicate the state is working with a population growth rate forecast averaging 1.2% annually; the Company has applied a 1.1% growth rate for demand forecasted in the North Dakota jurisdiction. Overall, the Company is forecasting a system average demand growth rate of 0.6% across all *NSP System* jurisdictions.

c. Data provided in Attachment A extends through the year 2030.

Preparer:	Mary Morrison
Title:	Resource Planning Analyst
Department:	Resource Planning and Bidding
Telephone:	612.330.5862
Date:	August 10, 2015

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Case No.:	PU-14-810		
Response To:	NDPSC	Data Request No.	11
Requestor:	Michael Diller		
Date Received:	January 7, 2015		

Question:

Reference NDPSC Data Request No. 5I, Attachment A

a) Please redo NDPSC Data Response No. 5i, Attachment A to make it non-trade secret and more useful for the hearing. Redo the non-trade secret section to only include "existing resources" to determine a baseline Long / (Short) Position. Make sure that this new schedule includes NSP's most recent capacity needs projections and reference the date of the projection. Below the baseline Position, include a separate line for each new resource's expected capacity to meet system capacity requirements including the date each is expected to come on line. The new resources section should include 3 segments, one for new resources already approved by the MN commission; another for resources that are expected to be approved by the MN commission; and a third section for resources that are not included in the first two but are preferred by NSP. Given this approach, the trade secret portion can be dropped from the schedule and the hearing will not be impeded by dealing with non-disclosure requirements. Last, add 5 more years to the worksheet to include years out to 2024.

b) Provide the same thing except on a North Dakota basis. In other words, instead of Non-Coincident Peak Demand for NSP's system, the first line would include North Dakota's projected NCPD and a calculated diversity factor on the second line to coincide with North Dakota's projected Demand Coincident with Peak number on the third line. Include North Dakota's share of Demand Resources then work through the applicable transmission adjustments and the MISO reserve planning margin to determine a Native Load Obligation for ND. This would then be followed with ND's share of existing resources and its share of purchased generation and sales to determine ND's share of resources and its Long / (Short) Position. Again, each future projected resource will be shown displaying only ND's share of the projected capacity. I understand that this may not be readily available. However, this is important to my analysis of

ND's needs and this proceeding. Make a good effort in developing the information.

Response:

a) and b) Please see Attachments A and B for the requested analyses.

As shown in Attachments A and B, based on the 2014 forecast, the Company's current supply portfolio shows a modest amount of excess capacity (between 1 and 2.5%) from 2015 through 2018 and virtually no excess capacity on a system-wide basis in 2019 and 2020. In 2021, the system then regains a small amount of excess capacity by increasing our current Manitoba Hydro purchase from anticipated new capacity that is under development. In 2024, however, we again show a system deficit of 234 MW. This load balance profile suggests that we are at risk of capacity deficits beginning in 2019 and 2020 if our projected loads change by even a very small amount. Indeed, even the 0.5 to 2.5 percent excess capacity shown on our assumed supply portfolio is modest given the normal forecast variability which can result in demand swings of 200 MW (2 percent) or more.

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

As requested, Attachments A and B also includes a scenario where all of our currently contemplated resources have been included. This includes: (1) the 98 MW accreditable capacity (187 MW nameplate) solar portfolio purchase which is the subject of this Case; (2) the Calpine Mankato combined-cycle expansion project (345 MW accreditable capacity); (3) the up-to 71 MW accreditable capacity (up to 100 MW nameplate) Geronimo solar project; (4) the capacity for the Black Dog 6 combustion turbine unit (207 MW accreditable capacity), for which an ADP has already been issued by the Commission; (5) a new short-term (four year) 75 MW capacity exchange with Manitoba Hydro; and (6) additional resources contemplated by our recently filed

Upper Midwest Resource Plan.[1] If all of the contemplated new generation is actually deployed, it will result in a system surplus in the 2019-2020 timeframe of about 6 to 7 percent (550 MW in 2019 and 685 MW in 2020) and address our resource need in 2024.

Additionally, these resource additions will also position us well to address issues identified in our 2015 Resource Plan beyond 2024. This includes the impacts of pending environmental regulation such as NOx regulations that may impact the continued use of our Sherco Units 1 and 2 as well as EPA's proposed Clean Power Plan. Furthermore, these resources help position us to address known long-term changes to the NSP System beyond 2024. For example, from 2025 through 2034, the first phase of the Mankato Energy Center and the Cottage Grove power purchase agreements will expire, the Manitoba Hydro power purchase agreement will expire, and our nuclear plant licenses will reach their end dates. As a result, we must begin to address nearly 75 percent of the energy producing resources on the NSP System.

Preparer:	Mary Morrison
Title:	Resource Planning Analyst
Department:	Resource Planning
Telephone:	612.330.5862
Date:	January 19, 2015

[1] Please note, we intend to file ADP applications for the Calpine and Geronimo projects once the MPUC issues a written order approving their purchase. We expect to file for approval for the Manitoba Hydro contract from the Commission in the next several months. Because it is a short-term purchase, approval by the MPUC is not required.

NSP Load Balance	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NSP System Peak Demand, July (Fall 2014 Forecast) @ generator	9,325	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
Coincident Factor with MISO	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
NSP System Peak Demand Coincident with MISO @ generator	8,858	8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
Transmission Loss Correction to Tranmission	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%
NSP System Peak Demand Coincident with MISO @ transmission	8,633	8,741	8,818	8,884	8,933	8,956	8,975	9,030	9,025	9,042	9,071	9,136	9,223	9,384	9,398	9,490
NSP System Load Management Forecast, July @ transmission	933	942	953	964	975	986	996	1,007	1,017	1,028	1,030	1,025	1,021	1,017	1,013	1,009
NSP System Peak Demand, Net of LM, Coincident with MISO @ transmission	7,700	7,800	7,864	7,920	7,958	7,970	7,978	8,023	8,008	8,014	8,041	8,111	8,202	8,367	8,385	8,482
Transmission Loss Correction to Generator	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%
NSP System Peak Demand, Net of LM, Coincident with MISO @ generator	7,901	8,004	8,070	8,127	8,166	8,178	8,187	8,233	8,217	8,224	8,251	8,323	8,416	8,586	8,604	8,703
MISO System Planning Reserve Margin	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
NSP System Native Load Obligation @ generator	**8,462**	**8,572**	**8,643**	**8,704**	**8,746**	**8,759**	**8,768**	**8,817**	**8,800**	**8,808**	**8,837**	**8,914**	**9,014**	**9,195**	**9,215**	**9,321**
Existing Resources	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Owned Generation	6,803	6,870	6,913	6,913	6,902	6,902	6,954	6,954	6,954	6,566	6,566	6,317	6,066	6,029	6,029	6,029
Purchased Generation	1,885	1,894	1,997	1,882	1,852	1,857	2,045	2,046	2,009	2,008	862	593	570	309	324	361
Sales	(50)	(50)	(25)	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Resources @ generator	**8,639**	**8,714**	**8,885**	**8,795**	**8,754**	**8,760**	**8,999**	**9,000**	**8,963**	**8,574**	**7,427**	**6,910**	**6,636**	**6,339**	**6,353**	**6,391**
Long/(Short) Position @ generator	**177**	**142**	**242**	**91**	**8**	**0**	**231**	**182**	**163**	**(234)**	**(1,410)**	**(2,004)**	**(2,378)**	**(2,856)**	**(2,862)**	**(2,931)**

Additional Resources

Resources Approved by the MPUC (Docket 12-1240)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Calpine Mankato - 2 (June 2019) (NG-CC-PPA)	-	-	-	-	308	308	308	308	308	308	308	308	308	308	308	308
Geronimo/Aurora (COD 12/2016, summer accreditation 6/2018) (Solar-PPA)	-	-	-	72	72	72	72	72	72	72	72	72	72	72	72	72
Black Dog 6 - (June 2020) (NG-CT)	-	-	-	-	-	207	207	207	207	207	207	207	207	207	207	207
Total Resources Currently Approved	**-**	**-**	**-**	**72**	**380**	**587**	**587**	**587**	**587**	**587**	**587**	**587**	**587**	**587**	**587**	**587**

Resources Anticipating Approval by the MPUC	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Manitoba Hydro - 75 MW Diversity Agreement (Period 6/1/2016-5/31/2020)	-	73	73	73	73	-	-	-	-	-	-	-	-	-	-	-
Solar Resource Acquisition (187 MW) docket 14-168 (COD 12/2016, summer accreditation 6/2018)	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98	98
Total Resources Anticipating Approval	**-**	**73**	**73**	**171**	**171**	**98**	**98**	**98**	**98**	**98**	**98**	**98**	**98**	**98**	**98**	**98**

Resources in the 2016 IRP Preferred Plan	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Preferred Plan - Wind Additions	-	-	-	-	-	-	89	89	118	118	207	207	266	266	266	266
Preferred Plan - Solar Additions	-	-	-	-	-	-	-	-	-	52	261	418	523	784	784	889
Preferred Plan - CT Additions	-	-	-	-	-	-	-	-	-	-	877	1,316	1,535	1,755	1,755	1,755
Resources in the 2016 IRP Preferred Plan	**-**	**-**	**-**	**-**	**-**	**-**	**89**	**89**	**118**	**171**	**1,346**	**1,942**	**2,325**	**2,805**	**2,805**	**2,910**

Subsequent Impact of Additional Resources	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Resources Approved by the MPUC (Docket 12-1240)	-	-	-	72	380	587	587	587	587	587	587	587	587	587	587	587
Resources Anticipating Approval by the MPUC	-	73	73	171	171	98	98	98	98	98	98	98	98	98	98	98
Resources in the 2016 IRP Preferred Plan	-	-	-	-	-	-	89	89	118	171	1,346	1,942	2,325	2,805	2,805	2,910
Additional Resources @ generator	-	73	73	243	551	684	773	773	803	855	2,030	2,626	3,009	3,490	3,490	3,594
Long/(Short) Position @ generator	**177**	**216**	**315**	**334**	**559**	**685**	**1,004**	**956**	**965**	**621**	**621**	**622**	**631**	**633**	**628**	**664**

Notes:

All resource capacity ratings represent MISO UCAP values.

Pending receipt of the written order in Docket 12-1240, the Commercial Operation Dates have been estimated.

NSP Load Balance - North Dakota - Summer	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
North Dakota Peak Demand, July (Fall 2014 Forecast) @ generator	480	490	496	502	508	513	519	525	535	539	543	547	551	555	559	563
Coincident Factor with MISO	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
North Dakota Peak Demand Coincident with MISO @ generator	456	466	471	477	482	487	493	499	508	512	516	520	523	527	531	535
Transmission Loss Correction to Transmission	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%
North Dakota Peak Demand Coincident with MISO @ transmission	444	454	459	465	470	475	481	486	495	499	503	506	510	514	517	521
ND Load Management Forecast, July @ transmission	64	64	64	64	65	65	65	65	65	66	66	65	65	65	65	65
North Dakota Peak Demand, Net of LM, Coincident with MISO @ transmission	380	390	395	401	405	410	416	421	430	433	437	441	444	448	452	456
Transmission Loss Correction to Generator	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%
North Dakota Peak Demand, Net of LM, Coincident with MISO @ generator	390	400	405	411	416	421	426	432	441	445	448	452	456	460	464	468
MISO System Planning Reserve Margin	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
North Dakota Native Load Obligation @ generator	**418**	**428**	**434**	**440**	**446**	**451**	**457**	**462**	**472**	**476**	**480**	**485**	**489**	**493**	**497**	**501**
NSP System Obligation	8,462	8,572	8,643	8,704	8,746	8,759	8,768	8,817	8,800	8,808	8,837	8,914	9,014	9,195	9,215	9,321
ND Obligation	418	428	434	440	446	451	457	462	472	476	480	485	489	493	497	501
ND Obligation as a Percentage of NSP System Obligation	4.94%	5.00%	5.02%	5.06%	5.09%	5.15%	5.21%	5.24%	5.37%	5.41%	5.43%	5.44%	5.42%	5.36%	5.39%	5.38%

ND Share of Existing Resources, Summer	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Owned Generation	336	343	347	350	352	355	362	365	373	355	357	343	329	323	325	324
Purchased Generation	93	95	100	95	94	96	107	107	108	109	47	32	31	17	17	19
Sales	(2)	(2)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Resources, Summer	**427**	**436**	**446**	**445**	**446**	**451**	**469**	**472**	**481**	**464**	**404**	**376**	**360**	**340**	**343**	**344**
Position - Long (Short), Summer	**9**	**7**	**12**	**5**	**0**	**0**	**12**	**10**	**9**	**(13)**	**(77)**	**(109)**	**(129)**	**(153)**	**(154)**	**(158)**

Subsequent Impact of Additional Resources - ND Share	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Resources Approved by the MPUC (Docket 12-1240)	-	-	-	4	19	30	31	31	31	32	32	32	32	31	32	32
Resources Anticipating Approval by the MPUC	-	4	4	9	9	5	5	5	5	5	5	5	5	5	5	5
Resources in the 2016 IRP Preferred Plan	-	-	-	-	-	-	5	5	6	9	73	106	126	150	151	157
Additional Resources	-	4	4	12	28	35	40	41	43	46	110	143	163	187	188	193
Position - Long (Short), Summer with Additional Resources	9	11	16	17	28	35	52	50	52	34	34	34	34	34	34	36

Notes:
All resource capacity ratings represent MISO UCAP values.
Pending receipt of the written order in Docket 12-1240, the Commercial Operation Dates have been estimated.

PUBLIC DOCUMENT –
TRADE SECRET DATA EXCISED

☐ **Non Public Document – Contains Trade Secret Data**
☒ **Public Document – Trade Secret Data Excised**
☐ **Public Document**

Xcel Energy			
Case No.:	PU-15-96		
Response To:	ND Public Service Advocacy Staff	Data Request No.	2-11
Requestor:	Richard A. Polich		
Date Received:	July 31, 2015		

Question:

Provide all calculations and spreadsheets used to derive the Table 6 on page 24 of Mr. Johnson's testimony in electronic format.

Response:

Please see Attachment A to this response.

Preparer:	Mary Morrison
Title:	Resource Planning Analyst
Department:	Resource Planning and Bidding
Telephone:	612.330.5862
Date:	August 10, 2015

EXHIBIT
tabbles
7

Table 10: Annual Rate Impact Analysis

GERONIMO	**2015**
Net Rate Impact	**0.000¢/kWh**

CALPINE	**2015**
Net Rate Impact	**0.000¢/kWh**

BLACK DOG 6	**2015**
Net Rate Impact	**0.000¢/kWh**

GERONIMO + CALPINE	**2015**
Net Rate Impact	**0.000¢/kWh**

CALPINE + BLACK DOG 6	**2015**
Net Rate Impact	**0.000¢/kWh**

GERONIMO + CALPINE + BLACK DOG 6	**2015**
Net Rate Impact	**0.000¢/kWh**

2016	2017	2018	2019	2020
0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh

2016	2017	2018	2019	2020
0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.014¢/kWh)	0.019¢/kWh

2016	2017	2018	2019	2020
0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.007¢/kWh)	0.005¢/kWh

2016	2017	2018	2019	2020
0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.003¢/kWh	0.035¢/kWh

2016	2017	2018	2019	2020
0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.021¢/kWh)	0.018¢/kWh

2016	2017	2018	2019	2020
0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.006¢/kWh	0.034¢/kWh

2021	2022	2023	2024	2025
0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.017¢/kWh	0.023¢/kWh

2021	2022	2023	2024	2025
0.012¢/kWh	0.012¢/kWh	0.011¢/kWh	0.009¢/kWh	0.014¢/kWh

2021	2022	2023	2024	2025
(0.004¢/kWh)	(0.006¢/kWh)	(0.010¢/kWh)	(0.011¢/kWh)	(0.015¢/kWh)

2021	2022	2023	2024	2025
0.027¢/kWh	0.028¢/kWh	0.026¢/kWh	0.032¢/kWh	0.023¢/kWh

2021	2022	2023	2024	2025
0.029¢/kWh	0.019¢/kWh	0.009¢/kWh	0.006¢/kWh	0.003¢/kWh

2021	2022	2023	2024	2025
0.055¢/kWh	0.046¢/kWh	0.036¢/kWh	0.021¢/kWh	0.016¢/kWh

Table 10: Annual Rate Impact Analysis

GERONIMO	2015
Net Rate Impact	0.000¢/kWh

CALPINE	2015
Net Rate Impact	0.000¢/kWh

BLACK DOG 6	2015
Net Rate Impact	0.000¢/kWh

GERONIMO + CALPINE	2015
Net Rate Impact	0.000¢/kWh

CALPINE + BLACK DOG 6	2015
Net Rate Impact	0.000¢/kWh

GERONIMO + CALPINE + BLACK DOG 6	2015
Net Rate Impact	0.000¢/kWh

2016	2017	2018	2019	2020
0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh

2016	2017	2018	2019	2020
0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.014¢/kWh)	0.019¢/kWh

2016	2017	2018	2019	2020
0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.007¢/kWh)	0.005¢/kWh

2016	2017	2018	2019	2020
0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.003¢/kWh	0.035¢/kWh

2016	2017	2018	2019	2020
0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.021¢/kWh)	0.018¢/kWh

2016	2017	2018	2019	2020
0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.006¢/kWh	0.034¢/kWh

2021	2022	2023	2024	2025
0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.017¢/kWh	0.023¢/kWh

2021	2022	2023	2024	2025
0.012¢/kWh	0.012¢/kWh	0.011¢/kWh	0.009¢/kWh	0.014¢/kWh

2021	2022	2023	2024	2025
(0.004¢/kWh)	(0.006¢/kWh)	(0.010¢/kWh)	(0.011¢/kWh)	(0.015¢/kWh)

2021	2022	2023	2024	2025
0.027¢/kWh	0.028¢/kWh	0.026¢/kWh	0.032¢/kWh	0.023¢/kWh

2021	2022	2023	2024	2025
0.029¢/kWh	0.019¢/kWh	0.009¢/kWh	0.006¢/kWh	0.003¢/kWh

2021	2022	2023	2024	2025
0.055¢/kWh	0.046¢/kWh	0.036¢/kWh	0.021¢/kWh	0.016¢/kWh

2026	2027	2028	2029	2030
0.009¢/kWh	0.017¢/kWh	0.016¢/kWh	0.023¢/kWh	0.008¢/kWh

2026	2027	2028	2029	2030
(0.002¢/kWh)	0.003¢/kWh	(0.001¢/kWh)	0.002¢/kWh	(0.013¢/kWh)

2026	2027	2028	2029	2030
(0.022¢/kWh)	(0.031¢/kWh)	(0.034¢/kWh)	(0.038¢/kWh)	(0.041¢/kWh)

2026	2027	2028	2029	2030
0.015¢/kWh	0.020¢/kWh	0.015¢/kWh	0.021¢/kWh	0.011¢/kWh

2026	2027	2028	2029	2030
(0.023¢/kWh)	(0.026¢/kWh)	(0.032¢/kWh)	(0.033¢/kWh)	(0.051¢/kWh)

2026	2027	2028	2029	2030
(0.006¢/kWh)	(0.009¢/kWh)	(0.016¢/kWh)	(0.014¢/kWh)	(0.034¢/kWh)

2031	2032	2033	2034	2035
0.020¢/kWh	(0.014¢/kWh)	0.010¢/kWh	(0.010¢/kWh)	0.011¢/kWh

2031	2032	2033	2034	2035
(0.017¢/kWh)	(0.041¢/kWh)	(0.020¢/kWh)	(0.041¢/kWh)	(0.020¢/kWh)

2031	2032	2033	2034	2035
(0.032¢/kWh)	(0.024¢/kWh)	(0.024¢/kWh)	(0.028¢/kWh)	(0.027¢/kWh)

2031	2032	2033	2034	2035
(0.013¢/kWh)	(0.014¢/kWh)	(0.004¢/kWh)	(0.021¢/kWh)	(0.002¢/kWh)

2031	2032	2033	2034	2035
(0.046¢/kWh)	(0.062¢/kWh)	(0.044¢/kWh)	(0.066¢/kWh)	(0.047¢/kWh)

2031	2032	2033	2034	2035
(0.033¢/kWh)	(0.037¢/kWh)	(0.027¢/kWh)	(0.049¢/kWh)	(0.029¢/kWh)

2036	2037	2038	2039	2040
0.008¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh

2036	2037	2038	2039	2040
(0.023¢/kWh)	(0.015¢/kWh)	(0.018¢/kWh)	0.012¢/kWh	(0.000¢/kWh)

2036	2037	2038	2039	2040
(0.029¢/kWh)	(0.030¢/kWh)	(0.026¢/kWh)	(0.028¢/kWh)	(0.029¢/kWh)

2036	2037	2038	2039	2040
(0.004¢/kWh)	(0.024¢/kWh)	(0.018¢/kWh)	0.012¢/kWh	(0.000¢/kWh)

2036	2037	2038	2039	2040
(0.051¢/kWh)	(0.043¢/kWh)	(0.044¢/kWh)	(0.015¢/kWh)	(0.029¢/kWh)

2036	2037	2038	2039	2040
(0.032¢/kWh)	(0.054¢/kWh)	(0.044¢/kWh)	(0.015¢/kWh)	(0.029¢/kWh)

2041	2042	2043	2044	2045
0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh

2041	2042	2043	2044	2045
(0.000¢/kWh)	(0.000¢/kWh)	(0.000¢/kWh)	(0.000¢/kWh)	(0.000¢/kWh)

2041	2042	2043	2044	2045
(0.032¢/kWh)	(0.033¢/kWh)	(0.034¢/kWh)	(0.036¢/kWh)	(0.036¢/kWh)

2041	2042	2043	2044	2045
(0.000¢/kWh)	(0.000¢/kWh)	(0.000¢/kWh)	(0.000¢/kWh)	(0.000¢/kWh)

2041	2042	2043	2044	2045
(0.032¢/kWh)	(0.033¢/kWh)	(0.034¢/kWh)	(0.036¢/kWh)	(0.036¢/kWh)

2041	2042	2043	2044	2045
(0.032¢/kWh)	(0.033¢/kWh)	(0.034¢/kWh)	(0.036¢/kWh)	(0.036¢/kWh)

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. E002/M-15-330

Dated this 4th day of December 2015

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_15-330_M-15-330
James J.	Bertrand	james.bertrand@stinson.com	Stinson Leonard Street LLP	150 South Fifth Street, Suite 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-330_M-15-330
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