

**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**

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1 **Q. Please state your name and place of employment.**

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

5 **Q. What position do you hold?**

6 A. I hold the position of Managing Director.

7 **Q. On whose behalf are you submitting this testimony?**

8 A. I am submitting this testimony on behalf of North Dakota Public Service  
9 Commission Advocacy Staff (“Staff”)

10 **Q. What is your educational background?**

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

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

17 **Q. Please describe your work experience.**

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

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

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

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

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

14 In July 1992, I transferred to the Rates and Regulatory Affairs Department  
15 of Consumers Energy as a Principal Rate Analyst. In that capacity, I  
16 performed studies relating to all facets of development and design of  
17 Consumers Energy's gas, retail, electric and electric wholesale rates.

18 During this period, I was heavily involved in the development of  
19 Consumers Energy's Direct Access program and in the development of  
20 Consumers Energy's Retail Open Access program. I also participated in  
21 the development of the Consumers Energy's revenue forecast.

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

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

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

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

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

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

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

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

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

6 **Q. Do you have any professional registrations?**

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

9 **Q. Have you published any papers?**

10 **A.** Yes, I have authored the following publications:

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

21 **Q. Have you testified in any other regulatory proceedings?**

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

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

7

## 8   **TESTIMONY PURPOSE AND SUMMARY**

9   **Q.**    **What is the purpose of your testimony?**

10   **A.**    The North Dakota Public Service Commission (“Commission”) hired GDS  
11           Associates, Inc. (“GDS”) to provide an analysis and recommendation  
12           concerning Northern States Power’s (“NSP”) need for additional  
13           generation resources. My testimony will cover four main areas including  
14           review of NSP’s Integrated Resource Plans (“IRP”), the need for additional  
15           generation resources, the cost impact on North Dakota customers of the  
16           345 MW Power Purchase Agreement with Mankato Energy Center, LLC  
17           (“Mankato PPA”) and an assessment of capacity risks.

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

20   **A.**    The Mankato Energy Center is located in Mankato, Minnesota. Calpine’s  
21           345 MW combined cycle (“CC”) unit will be located on the same site as  
22           the existing Mankato Energy Center CC unit. NSP currently has a PPA

1 with Calpine for 360 MW of capacity from the existing Mankato project.  
2 NSP has entered into a new 20 year PPA with a dollars per kW-month  
3 price for capacity and dollars per MWH price for energy that escalate  
4 annually after the first year of operation. All fuel used by the new unit will  
5 be procured, delivered and paid for by NSP.

6 **Q. Please summarize your testimony.**

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

1 **Q. How is your testimony organized?**

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

3 1. **Forecasts and Integrated Resource Plan Review** – Review and  
4 analysis of the IRP and forecast data presented in this case. Provides  
5 the basis for using NSP's Upper Midwest Resource Plan 2016-2030,  
6 filed in North Dakota, Case No. PU-15-19.

7 2. **2019 - 2024 Capacity Obligations** – Analysis of NSP's generation  
8 resource needs based upon the 2015 IRP, focusing on 2019-2024  
9 period in which NSP's capacity needs are in question.

10 3. **North Dakota Ratepayers Cost Impact** – Analysis of cost impact on  
11 NSP's ratepayers in North Dakota.

12 4. **Capacity Risks** – Assessment of the comparative risks of adding new  
13 or of not adding capacity as proposed by NSP.

14 5. **Conclusions** – Summary of testimony and recommendations.

15 **Q. Have you prepared any Exhibits?**

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

17	<b><u>EXHIBIT</u></b>	<b><u>DESCRIPTION</u></b>
18	1.	Richard A. Polich Curriculum Vitae
19	2.	Regulatory Proceedings Testimony List
20	3.	NSP Response to Data Request 2-1
21	4.	NSP Response to Data Request 2-3

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

7       **NSP FORECAST AND IRP REVIEW**

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

9       A.     I reviewed portions of all of the forecasts referenced in the testimony of  
10       NSP witnesses and provided in Data Request 2-1 (Staff Exhibit 3). On  
11       page 7 of the application and on page 2, line 20 of NSP witness Kurtis J.  
12       Haeger's testimony, it states the Fall 2011 Forecast is the basis for  
13       identifying NSP's need for capacity to be filled by the Mankato project. On  
14       page 5, lines 5-8 of his testimony, Mr. Haeger refers to a spring 2012  
15       forecast, fall 2012 forecast, spring 2013 forecast, fall 2014 forecast and  
16       2015 Resource Plan forecast. In addition, Mr. Paul B. Johnson's testimony  
17       introduces additional capacity need forecasts.

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

20       A.     As stated on page 7 of NSP's Application and discussed in Mr. Haeger's  
21       testimony on page 2, lines 20 – 21, NSP's capacity obligation is based

1           upon the Fall 2011 forecast (“Fall 2011 Forecast”) which was an update of  
2           NSP’s 2010 Integrated Resource Plan.

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

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

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

21   A.   Yes. I have reviewed the various forecasts presented and used by NSP in  
22          this case. In response to Data Request 2-1, NSP (Staff Exhibit 3) provided

1 the data from the various forecasts and integrated resource plans  
2 referenced in Mr. Haeger's testimony. My review of these forecasts  
3 revealed that NSP did not use the same reserve margin requirements and  
4 has applied different correction factors to adjust to MISO coincident peaks  
5 in determining capacity requirements. Data Request 2-3 (Exhibit 4)  
6 indicates that MISO has changed its Planning Reserve Margin ("PRM")  
7 several times since the 2010 IRP. MISO currently applies the PRM to 95%  
8 of NSP's peak capacity ("Coincident Peak Factor"). NSP's forecasts  
9 though 2014 do not include the current MISO 7.1% PRM or the MISO 95%  
10 Coincident Peak factor.

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

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

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

3 A. Yes, Mr. Johnson did include the current MISO reserve margin calculation  
 4 methodology in the 2014 Forecast and the 2015 IRP. However, the Fall  
 5 2011 Forecast does not reflect the current MISO reserve margin  
 6 calculation methodology. The Fall 2011 Forecast should have been  
 7 adjusted to reflect the current MISO reserve margin calculation  
 8 methodology.

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

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

**TABLE A - NSP FORECASTS DIFFERENCES IN MISO CAPACITY OBLIGATIONS**

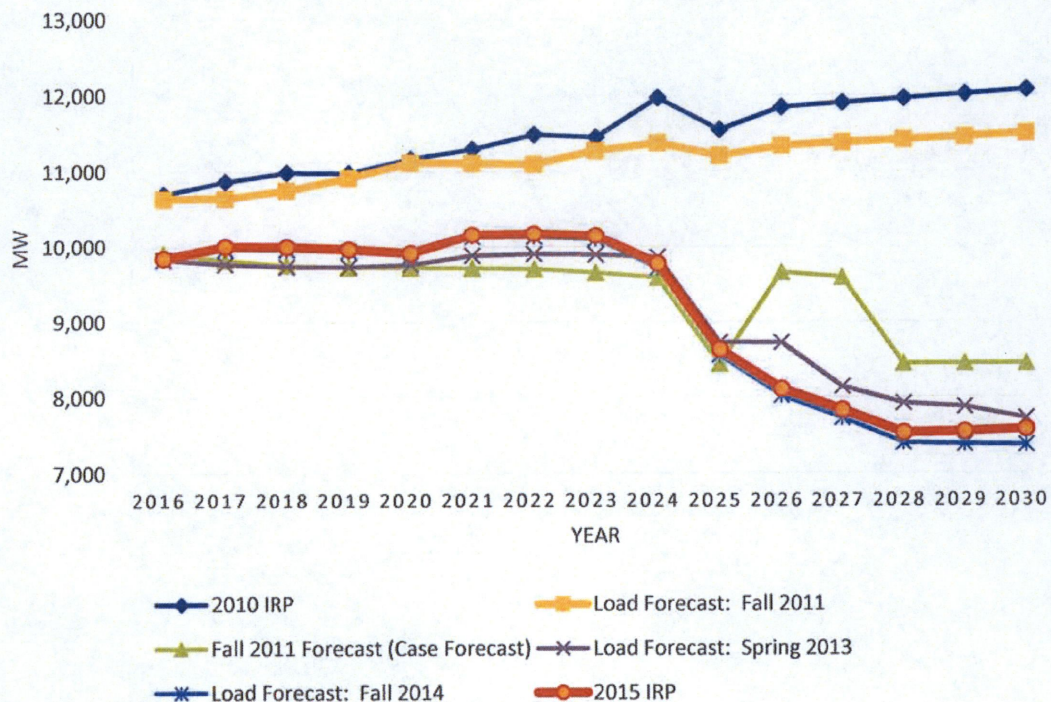
NSP FORECAST	CHANGE IN CAPACITY OBLIGATION - MW*															
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2010 IRP Forecast	(1,012)	(1,024)	(1,034)	(1,044)	(1,052)	(1,062)	(1,068)	(1,074)	(1,081)	(1,086)	(1,090)	(1,096)	(1,101)	(1,106)	(1,111)	(1,116)
Fall 2011 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 calculation methodology

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

3 A. Yes. As can be seen in the following chart, NSP has updated its existing  
4 generation resources in each of the forecasts. This chart shows a wide  
5 variation in the amount of existing generation resources NSP expects to  
6 have available to meet its MISO capacity obligations. For example, in  
7 2023, the Fall 2011 Forecast (Case Forecast) amount of existing  
8 generation resources are 496 MW (4.9%) LOWER than the 2015 IRP.  
9 Differences in forecasts of existing NSP generation resources are critical  
10 in determining the need for additional capacity and provide another key  
11 reason why the most recent forecast should be used.

### EXISTING GENERATION FORECAST



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

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

**TABLE B - Comparison 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.

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

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

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

1 **Q. Would you make any adjustments to NSP’s forecasted generation**  
 2 **resource additions contained in NSP’s 2015 IRP?**

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

**TABLE C - NSP 2015 IRP Forecast - Adjusted**

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

1 **2019-2024 CAPACITY OBLIGATION**

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

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

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

12 A. The decrease in NSP's Total Forecast Supply resources in 2024 is due to  
13 the retirement of 33 MW of natural gas generation (Blue Lake, French  
14 Island and Granite City) and 83 MW of biomass (Bayfront and French  
15 Island). The 2025 decrease in NSP's Total Forecast Supply resources in  
16 2025 is due to the 850 MW loss of Manitoba Hydro PPA and 358 MW  
17 Invenergy PPA (CC).

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

20 A. Based upon NSP's 2015 IRP forecast of current MISO capacity obligation,  
21 forecasted load growth, existing generation resources and resource  
22 additions already approved, NSP should not increase generation capacity

1           until 2025. It would not be prudent to add capacity through a 20-year PPA  
2           starting in 2019 because 30% of the PPA contract period will have expired  
3           prior to the anticipated need for capacity.

4

## 5    **NORTH DAKOTA RATEPAYERS COST IMPACT**

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

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

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

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

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

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

3 A. No. First, the base model used for calculating the Mankato PPA net cost  
4 does not include the Black Dog 6 unit. Second the projected 2019 avoided  
5 O&M costs are [. . . . .**TRADE SECRET** . . . . .] and average over [. . . . .  
6 . . . **TRADE SECRET** . . . . .] over the life of the contract.

7 These amounts are more than significantly higher than the variable O&M  
8 costs used in the Strategist model for potential generation resources  
9 (response to Data Request 1-1, Staff Exhibit 8). Third, the calculated  
10 avoided energy costs with the Mankato [**TRADE SECRET DATA BEGINS**  
11 .....  
12 .....**TRADE SECRET DATA ENDS**] in the Strategist  
13 model inputs for potential generation resources.

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

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

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

3 A. NSP provided data in response to Data Request 2-1 that contains  
 4 sufficient information to approximate the net cost of Mankato PPA with  
 5 Black Dog 6 included in NSP’s generation resources. It needs to be noted  
 6 that this comparison includes the high variable O&M avoided cost and  
 7 energy avoided cost estimates included in NSP’s calculations. With this in  
 8 mind, Table D, row 1 shows the cost savings of adding Black Dog 6 to  
 9 NSP’s generation resource mix. The second row shows NSP’s calculated  
 10 net rate impact of adding both Black Dog 6 and Mankato PPA. The third  
 11 row of Table D, shows the net rate difference of Rows 1 and 2. The net  
 12 rate difference times the annual sales in Row 4 results in annual  
 13 cost/(savings). The Total 2019-2024 cost increase to NSP ratepayers is  
 14 projected to be over \$39.7 million during the period in which NSP does not  
 15 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
<b>NET RATE DIFFERENCE (\$/MWh)</b>	<b>(\$0.14)</b>	<b>\$0.13</b>	<b>\$0.33</b>	<b>\$0.25</b>	<b>\$0.18</b>	<b>\$0.17</b>
Fall 2014 Sales Forecast, MWh	42,708,090	42,860,052	42,822,135	43,003,977	42,974,865	43,131,691
<b>ANNUAL COST/(SAVINGS) OF MANKATO PPA</b>	<b>(\$5,940,980)</b>	<b>\$5,591,460</b>	<b>\$14,153,853</b>	<b>\$10,633,093</b>	<b>\$7,874,467</b>	<b>\$7,450,983</b>

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

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

2 A. Adding the Mankato PPA to NSP generation resources reduces  
3 generation from other generation resources or power purchased from  
4 MISO. Reduced MISO power purchases will not avoid any variable O&M  
5 costs. The Mankato PPA will not result in any NSP generation plants  
6 being retired in the next six years, so NSP will still incur the fixed O&M  
7 costs of those units. The only O&M costs avoided as a result of the  
8 Mankato PPA will be variable O&M costs. In response to Data Request 1-  
9 1, NSP provided the expected variable O&M costs for various types of  
10 generation resources and the highest variable O&M cost was for a coal  
11 unit, with the projected 2019 [.....**TRADE SECRET DATA**  
12 .....]. It is more than likely the Mankato PPA will result in  
13 reduced generation of natural gas simple cycle or combined cycle  
14 generation resources, and the data input into the Strategist model show  
15 the projected 2019 variable O&M costs for these type of [**TRADE**  
16 **SECRET DATA BEGINS** .....**TRADE**  
17 **SECRET DATA ENDS**] included in the calculations that produced Table 7  
18 of Mr. Johnson's testimony.

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

20 A. Adding the Mankato PPA to NSP generation resources has the potential  
21 to reduce generation from other power generation units or reduce  
22 purchases from MISO. The avoided energy costs typically include fuel and

1 purchase power costs and maybe variable costs associated with reagents  
2 used in the power plant. The modeling data provided by NSP in response  
3 to Data Request 1-1 indicate the highest energy costs to be in the range [.  
4 ..... **TRADE SECRET DATA** .....]. The data used to  
5 calculate the figure in Table 7 of Mr. Johnson’s testimony indicate the  
6 avoided 2019 energy costs with the Mankato PPA [. .....  
7 .....**TRADE SECRET DATA**..... ]  
8 expensive optional generation source.

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

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

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

3 A. Yes. I have calculated the additional costs due to adjusting NSP's  
 4 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
<b>Additional Cost of Mankato PPA</b>	<b>\$21,461,252</b>	<b>\$40,419,908</b>	<b>\$43,212,554</b>	<b>\$38,685,739</b>	<b>\$33,560,098</b>	<b>\$29,604,504</b>

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

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

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

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

11 A. Yes. In Tables F, I show the net cost to North Dakota electric ratepayers  
 12 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)	<b>(\$5,940,980)</b>	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
<b>TOTAL ANNUAL COST INCREASE</b>	<b>\$15,520,273</b>	<b>\$46,011,368</b>	<b>\$57,366,407</b>	<b>\$49,318,832</b>	<b>\$41,434,565</b>	<b>\$37,055,486</b>
North Dakota Percentage of Load *	5.09%	5.15%	5.21%	5.24%	5.37%	5.41%
<b>North Dakota Ratepayer Proportional Cost</b>	<b>\$789,982</b>	<b>\$2,369,585</b>	<b>\$2,988,790</b>	<b>\$2,584,307</b>	<b>\$2,225,036</b>	<b>\$2,004,702</b>

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

1

2 **CAPACITY RISK**

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

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

16 **Q. Are there fuel risks associated with this PPA?**

17 A. Yes. NSP has contracted to supply and pay all fuel costs for the project,  
18 making it essentially a tolling agreement. The US has seen a lot of  
19 volatility of natural gas prices over the last 20 years. Recent regulations  
20 regarding CO<sub>2</sub> emissions is likely to increase the amount of natural gas-  
21 fired generation, which may drive natural gas prices upward. Over the next  
22 ten years, natural gas prices could experience major price swings and

1           cause NSP ratepayers to potentially incur higher costs than those  
2           projected by NSP. Again, approving the Mankato PPA this far in advance  
3           of NSP's need for capacity has significant risk.

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

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

15

16   **CONCLUSION**

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

18   A.   NSP's basis of its need for additional capacity is the Fall 2011 Forecast  
19       (Page 7 of application), which is outdated. NSP Witnesses, Mr. Haeger  
20       and Mr. Johnson discuss additional forecasts which do not contain the  
21       most current NSP up-to-date assessment of its loads, generation  
22       capability of current resources, known market conditions, load

1 management capability or current MISO calculation methods for  
2 determining capacity obligation. The 2015 IRP should be used as the  
3 basis for determining NSP's need for additional capacity. The 2015 IRP  
4 shows that the earliest need for additional capacity is 2025 and adding  
5 Mankato PPA prior to 2025 will likely cost North Dakota ratepayers over  
6 \$12.9 million. Therefore, I recommend the North Dakota Public Service  
7 Commission deny NSP's request for Advanced Determination of  
8 Prudence.

9 **Q. What other conclusions have you reached?**

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

- 12 1. NSP does not need additional capacity until 2025 and is long at least  
13 148 MW up through 2024.
- 14 2. The calculations of net rate impact of adding the Mankato PPA should  
15 have included Black Dog 6.
- 16 3. NSP appears to have overestimated the avoided costs of adding  
17 Mankato PPA.
- 18 4. NSP has underestimated the impact of adding the Mankato PPA to its  
19 generation resource mix.
- 20 5. Adding unneeded generation resources six years prior to the need for  
21 capacity has unnecessary risks.

1 **Q. Does this conclude your testimony?**

2 **A. Yes, it does.**

**STATE OF NORTH DAKOTA**  
**PUBLIC SERVICE COMMISSION**

**Norther States Power Company**  
**Advance Prudence – 345 MW Mankato Energy Center**

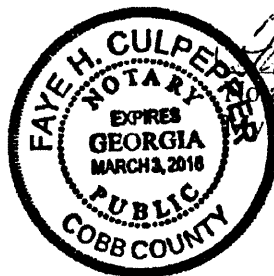
**Case No. PU-15-96**

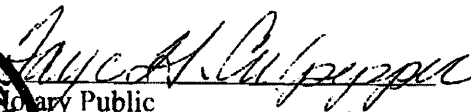
**STATE OF GEORGIA**                    )  
  ) ss.  
**COUNTY OF \_\_\_\_\_**            )

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.



  
Notary Public  
Commission Expires: March 3, 2018



**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.

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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 negotiation 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 grid 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 used 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.

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## **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**

<b>CASE</b>	<b>ON BEHALF</b>	<b>TITLE</b>
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



- 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                      Data Request No.                      2-1  
 Advocacy Staff

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



	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	10,653	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
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	1,812
Gas	3,660	3,660	4,050	4,245	4,441	4,441	4,636	4,636	4,636	4,838	4,838	5,447	5,878	6,187	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
Peak	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coincident 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
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
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	5,553	5,369	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: 2011-2025 Upper Midwest Resource Plan  
Filing Date: August 2010  
Load Forecast: Spring 2010

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	9,328	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
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	1,287	1,238	1,212	1,213	1,323	1,313	1,270	1,219	372	1,270	1,219	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: 2011-2025 Resource Plan Supplemental  
Filing Date: December 2012  
Load Forecast: Fall 2012  
CON Proceeding  
Testimony: Establish Size, Type, Timing in CAP

	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	3,799%	3,799%	3,799%	3,799%	3,799%	3,799%	3,799%	3,799%	3,799%	3,799%	3,799%	3,799%	3,799%	3,799%	3,799%	3,799%	3,799%
Reserve Margin	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
Obligation	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
Coal	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
Nuclear	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
Gas	1,385	1,241	1,238	1,189	1,162	1,162	1,162	1,383	1,388	1,388	1,317	1,366	1,366	1,366	1,366	1,366	1,366
Wind, Hydro, Bio	13	23	35	49	66	83	103	103	103	103	103	103	103	103	103	103	103
Solar	1,033	1,042	1,051	1,063	1,074	1,085	1,096	1,106	1,116	1,120	1,116	1,111	1,106	1,102	1,098	1,094	1,090
Load Management	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
Resources	487	69	68	-93	-218	-307	-374	-349	-426	-515	-620	-1,808	-1,870	-2,517	-2,800	-2,905	-3,128
Long (Short)																	

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	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	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
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
Coal	2,709	2,492	2,391	2,414	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
Nuclear	1,619	1,645	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	1,643
Gas	3,388	3,362	3,431	3,457	3,446	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	128	128	128	127	126	125	125	124	124	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: CAP CON Docket Compliance Filing  
 Filing Date: September 2014  
 Load Forecast: Fall 2014

	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%
MISO Planning Reserve	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
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
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	1,069	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	7,509
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

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
Black Dog 6	0	0	0	208	208	208	208	208	208	208	208	208	208	208	208
Calpine ME2	0	0	0	278	278	278	278	278	278	278	278	278	278	278	278
Geronomo/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

- 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                      Data Request No.                      2-3  
 Advocacy Staff

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%



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.

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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:**

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

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)		
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
<b>2010 RPT Forecast</b>																	
Peak	9,761	9,873	9,985	10,082	10,180	10,283	10,383	10,415	10,477	10,538	10,593	10,633	10,685	10,738	10,785	10,835	10,886
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%
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%
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
<b>GENERATION RESOURCES</b>																	
Coal	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	2,423
Nuclear	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	1,812	1,812
Gas	3,660	4,050	4,245	4,441	4,636	4,838	5,038	5,238	5,441	5,647	5,857	6,070	6,287	6,504	6,726	6,951	7,178
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
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
<b>Long (Short)</b>	<b>700</b>	<b>450</b>	<b>543</b>	<b>611</b>	<b>632</b>	<b>537</b>	<b>634</b>	<b>695</b>	<b>825</b>	<b>726</b>	<b>1,190</b>	<b>728</b>	<b>969</b>	<b>975</b>	<b>980</b>	<b>985</b>	<b>990</b>

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)		
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
<b>2011 Forecast</b>																	
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	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%
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%
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
<b>GENERATION RESOURCES</b>																	
Coal	2,752	2,495	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	11,709	11,096	11,269	11,371	11,206	11,332	11,371	11,409	11,445	11,491
<b>Long (Short)</b>	<b>1,465</b>	<b>1,268</b>	<b>981</b>	<b>897</b>	<b>909</b>	<b>983</b>	<b>1,103</b>	<b>1,017</b>	<b>940</b>	<b>1,062</b>	<b>1,127</b>	<b>936</b>	<b>1,038</b>	<b>1,042</b>	<b>1,046</b>	<b>1,049</b>	<b>1,053</b>



# NORTHERN STATES POWER LOAD FORECASTS

**LINE ASSUMPTIONS:**

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

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)		
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
31	9,328	9,428	9,524	9,613	9,708	9,799	9,881	9,963	10,029	10,082	10,123	10,151	10,182	10,213	10,248	10,287	10,328
32	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%
33	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%
34	9,491	9,593	9,690	9,781	9,877	9,970	10,063	10,137	10,204	10,258	10,300	10,328	10,258	10,300	10,328	10,328	10,328
35	<b>GENERATION RESOURCES</b>																
36	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
37	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
38	3,476	3,476	3,533	3,437	3,424	3,424	3,424	3,310	3,310	3,310	3,310	3,310	3,310	3,310	3,310	3,015	3,015
39	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
40	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
41	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
42	824	349	226	41	(121)	(244)	(330)	(422)	(503)	(604)	(713)	(1,887)	(604)	(713)	(1,887)	(1,887)	(1,887)
43	<b>Resources</b>																
44	<b>Long (Short)</b>																

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)		
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
45	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
46	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%
47	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%
48	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
49	<b>GENERATION RESOURCES</b>																
50	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
51	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
52	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	2,992	2,194	2,194	2,033
53	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
54	13	23	35	49	66	83	103	103	103	103	103	103	103	103	103	103	103
55	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
56	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
57	677	260	260	102	(22)	(109)	(174)	(147)	(223)	(310)	(413)	(1,601)	(1,661)	(2,307)	(2,589)	(2,692)	(2,914)
58	<b>Long (Short)</b>																



# NORTHERN STATES POWER LOAD FORECASTS

**LINE ASSUMPTIONS:**

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

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
96	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	
97	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%	
98	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	
99	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%	
100	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	
101																
102	<b>GENERATION RESOURCES</b>															
103	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	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	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	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	25	131	137	143	149	156	165	175	187	202	221	242	269	301	339	
108	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	10,086	9,769	9,846	10,004	9,999	9,970	9,970	10,150	9,772	8,628	8,106	7,827	7,526	7,536	7,569	
110	<b>239</b>	<b>313</b>	<b>235</b>	<b>152</b>	<b>71</b>	<b>301</b>	<b>252</b>	<b>232</b>	<b>(165)</b>	<b>(1,341)</b>	<b>(1,935)</b>	<b>(2,308)</b>	<b>(2,787)</b>	<b>(2,793)</b>	<b>(2,861)</b>	
111	<b>Resource Additions</b>															
112	0	0	0	208	208	208	208	208	208	208	208	208	208	208	208	
113	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
114	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
115	(1)	(1)	0	1	3	4	4	4	4	4	4	4	4	3	3	
116	20	36	53	72	94	103	103	102	102	101	101	100	100	99	98	
117	19	35	53	281	305	315	315	314	314	313	313	312	312	310	309	
118	<b>10,096</b>	<b>9,769</b>	<b>9,865</b>	<b>10,039</b>	<b>10,052</b>	<b>10,251</b>	<b>10,491</b>	<b>10,464</b>	<b>10,086</b>	<b>8,941</b>	<b>8,419</b>	<b>8,139</b>	<b>7,838</b>	<b>7,846</b>	<b>7,878</b>	
119	<b>258</b>	<b>348</b>	<b>288</b>	<b>433</b>	<b>376</b>	<b>616</b>	<b>567</b>	<b>546</b>	<b>149</b>	<b>(1,028)</b>	<b>(1,622)</b>	<b>(1,996)</b>	<b>(2,475)</b>	<b>(2,483)</b>	<b>(2,552)</b>	

- 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                      Data Request No.                      2-4  
Advocacy Staff

Requestor: Richard A. Polich

Date Received: July 31, 2015

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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.



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

- Non Public Document – Contains Trade Secret Data  
 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

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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.<sup>1</sup> 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.

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

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<sup>1</sup> 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.

<b>NSP Load Balance</b>	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	9,325	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 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%
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%
<b>NSP System Native Load Obligation @ generator</b>	<b>8,462</b>	<b>8,572</b>	<b>8,643</b>	<b>8,704</b>	<b>8,746</b>	<b>8,759</b>	<b>8,768</b>	<b>8,817</b>	<b>8,800</b>	<b>8,808</b>	<b>8,837</b>	<b>8,914</b>	<b>9,014</b>	<b>9,195</b>	<b>9,215</b>	<b>9,321</b>
<b>Existing Resources</b>	<b>6,803</b>	<b>6,870</b>	<b>6,913</b>	<b>6,913</b>	<b>6,902</b>	<b>6,902</b>	<b>6,954</b>	<b>6,954</b>	<b>6,954</b>	<b>6,566</b>	<b>6,566</b>	<b>6,317</b>	<b>6,066</b>	<b>6,029</b>	<b>6,029</b>	<b>6,029</b>
Owned 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
Purchased Generation	(50)	(50)	(25)	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales	177	142	242	91	8	0	231	182	163	(234)	(1,410)	(2,004)	(2,378)	(2,856)	(2,931)	(2,931)
<b>Existing Resources @ generator</b>	<b>8,639</b>	<b>8,714</b>	<b>8,885</b>	<b>8,795</b>	<b>8,754</b>	<b>8,760</b>	<b>8,999</b>	<b>9,000</b>	<b>8,963</b>	<b>8,574</b>	<b>7,427</b>	<b>6,910</b>	<b>6,636</b>	<b>6,339</b>	<b>6,353</b>	<b>6,391</b>
<b>Long/ (Short) Position @ generator</b>	<b>177</b>	<b>142</b>	<b>242</b>	<b>91</b>	<b>8</b>	<b>0</b>	<b>231</b>	<b>182</b>	<b>163</b>	<b>(234)</b>	<b>(1,410)</b>	<b>(2,004)</b>	<b>(2,378)</b>	<b>(2,856)</b>	<b>(2,862)</b>	<b>(2,931)</b>
<b>Additional Resources</b>																
<b>Resources Approved by the MPUC (Docket 12-1240)</b>																
Calpine Mankato - 2 (June 2019) (NG-CC-PPA)						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
<b>Total Resources Currently Approved</b>				<b>72</b>	<b>380</b>	<b>587</b>	<b>587</b>	<b>587</b>	<b>587</b>	<b>587</b>	<b>587</b>	<b>587</b>	<b>587</b>	<b>587</b>	<b>587</b>	<b>587</b>
<b>Resources Anticipating Approval by the MPUC</b>																
Manitoba Hydro - 75 MW Diversity Agreement (Period 6/1/2016-5/31/2020)		73	73	73	73	-	-	-	-	-	-	-	-	-	-	-
Solar Resources 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
<b>Total Resources Anticipating Approval</b>		<b>73</b>	<b>73</b>	<b>171</b>	<b>171</b>	<b>98</b>	<b>98</b>	<b>98</b>	<b>98</b>	<b>98</b>	<b>98</b>	<b>98</b>	<b>98</b>	<b>98</b>	<b>98</b>	<b>98</b>
<b>Resources in the 2016 IRP Preferred Plan</b>																
Preferred Plan - Wind Additions																
Preferred Plan - Solar Additions							89	89	118	118	207	207	266	266	266	266
Preferred Plan - CT Additions																
<b>Resources in the 2016 IRP Preferred Plan</b>							<b>89</b>	<b>89</b>	<b>118</b>	<b>171</b>	<b>1,346</b>	<b>1,316</b>	<b>1,535</b>	<b>1,755</b>	<b>1,755</b>	<b>2,910</b>
<b>Subsequent Impact of Additional Resources</b>																
Resources Approved by the MPUC (Docket 12-1240)																
Resources Anticipating Approval by the MPUC																
Resources in the 2016 IRP Preferred Plan																
<b>Additional Resources @ generator</b>																
<b>Long/ (Short) Position @ generator</b>	<b>177</b>	<b>216</b>	<b>315</b>	<b>334</b>	<b>551</b>	<b>684</b>	<b>773</b>	<b>956</b>	<b>965</b>	<b>621</b>	<b>621</b>	<b>622</b>	<b>631</b>	<b>633</b>	<b>628</b>	<b>664</b>

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.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
<b>NSP Load Balance - North Dakota - Summer</b>																
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%
<b>North Dakota Native Load Obligation @ generator</b>	<b>418</b>	<b>428</b>	<b>434</b>	<b>440</b>	<b>446</b>	<b>451</b>	<b>457</b>	<b>462</b>	<b>472</b>	<b>476</b>	<b>480</b>	<b>485</b>	<b>489</b>	<b>493</b>	<b>497</b>	<b>501</b>
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%
<b>ND Share of Existing Resources, Summer</b>																
Owned Generation	356	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)	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Existing Resources, Summer</b>	<b>427</b>	<b>436</b>	<b>446</b>	<b>445</b>	<b>446</b>	<b>451</b>	<b>469</b>	<b>472</b>	<b>481</b>	<b>464</b>	<b>404</b>	<b>376</b>	<b>360</b>	<b>340</b>	<b>343</b>	<b>344</b>
<b>Position - Long (Short), Summer</b>																
	9	7	12	5	0	0	12	10	9	(13)	(77)	(109)	(129)	(153)	(154)	(158)
<b>Subsequent Impact of Additional Resources - ND Share</b>																
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
<b>Additional Resources</b>	<b>-</b>	<b>4</b>	<b>4</b>	<b>12</b>	<b>28</b>	<b>35</b>	<b>40</b>	<b>41</b>	<b>43</b>	<b>46</b>	<b>110</b>	<b>143</b>	<b>163</b>	<b>187</b>	<b>188</b>	<b>193</b>
<b>Position - Long (Short), Summer with Additional Resources</b>	<b>9</b>	<b>11</b>	<b>16</b>	<b>17</b>	<b>28</b>	<b>35</b>	<b>52</b>	<b>50</b>	<b>52</b>	<b>34</b>	<b>34</b>	<b>34</b>	<b>34</b>	<b>34</b>	<b>34</b>	<b>36</b>

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                      Data Request No.                      2-11  
Advocacy Staff

Requestor: Richard A. Polich

Date Received: July 31, 2015

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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.

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



**Table 10: Annual Rate Impact Analysis**

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

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**

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

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)