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Rebuttal Testimony and Schedules
Paul B. Johnson

Before the North Dakota Public Service Commission
State of North Dakota

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
Exhibit___(PBJ-2)

Rebuttal of Advocacy Staff (Polich) Testimony

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Paul B. Johnson. I am Director of Resource Planning and Bidding for Xcel Energy. I provided Direct Testimony in this matter on a variety of resource planning issues.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to specific issues raised in the Direct Testimony of Richard A. Polich, P.E. on behalf of the Commission Advocacy Staff. I also provide information on how the addition of the Mankato PPA in 2019 is a reasonable resource addition under the circumstances.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Mr. Polich provides a resource planning analysis narrowly focused on the Company's load and resources in the 2019-25 timeframe. He concludes that the Company does not need additional capacity until the 2025 timeframe. He recommends that the Commission deny the ADP for the Mankato PPA commencing in 2019.

Mr. Polich states that the Company has a capacity need in 2025. Based on the current loads and resources forecast, I conclude the Company has a capacity need in 2024.

Given this need in 2024, the Company concludes that carrying the Mankato PPA from 2019 to 2023 is overall a better deal for ratepayers than deploying a combustion turbine (or combined-cycle) unit in 2024 to meet the outyear need. The Mankato PPA is aggressively-priced and provides us combined-cycle capacity and energy at about the equivalent overall cost of a combustion turbine and its associated energy. In addition, adding combined-cycle capacity to the system provides optionality and flexibility to address a number of evolving circumstances as I describe later in this testimony.

We acknowledge that the timing of the Mankato PPA is not ideal as the generation comes on line a few years prior to the need indicated by Mr. Polich's Table C. However, Mr. Polich substantially overstates the cost of deploying the Mankato PPA in 2019 and he ignores all of the other risks and benefits that provide value in moving forward at this time.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Mr. Polich's testimony addresses four main topics: (i) forecast issues, (ii) 2019-2024 capacity obligations, (iii) North Dakota ratepayer impacts, and (iv) capacity risks. While my Rebuttal Testimony addresses each of those topic areas, I have structured this testimony to focus on the benefits of the Mankato PPA and the problems we have identified in Mr. Polich's analysis. These topics are:

- Load and Resource Discussion;
- Mankato PPA Cost Impact;
- Capacity Risks;
- Conclusion.

II. LOAD AND RESOURCES DISCUSSION

Q. MR. POLICH TESTIFIES THAT NEW CAPACITY IS NOT NEEDED UNTIL 2025 BASED ON HIS REVIEW OF THE 2015 FORECAST. HOW DO YOU RESPOND?

A. First of all, the Company accepts, for purposes of this case, Mr. Polich's premise that the most up-to-date forecast should be used. The Company has prepared an up-to-date load and resources table based on the 2015 IRP forecast which is shown below on Table 1. Table 1 shows that with the Company's current resources, it has a capacity need in 2024 of 165 MW. Adding the Black Dog 6 project, but removing the resources not approved by, or likely not to be approved by, the Commission results in aforecasted capacity need of 117 MW in 2024.

Table 1: Updated Load and Resources

Obligation (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak (MW)	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Peak	8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
MISO Planning Reserve	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
Obligation (MW)	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
Generation Resources	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Coal	2,372	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
Nuclear	1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Natural Gas	3,451	3,476	3,476	3,465	3,465	3,465	3,465	3,465	3,137	2,824	2,576	2,325	2,090	2,090	2,090
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
RDF/Biomass - Owned	96	96	96	96	96	96	96	96	36	36	36	36	0	0	0
Biomass/RDF - PPA	145	145	122	110	109	109	109	84	84	84	80	47	0	0	0
Wind - PPA	181	181	181	157	157	215	215	193	180	158	152	140	135	118	117
Wind - Owned	48	48	48	48	48	99	99	99	99	99	99	99	99	99	99
Hydro - Owned	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Hydro - PPA	791	788	788	788	715	837	830	830	830	3	3	3	3	3	3
Solar	25	131	137	143	149	156	165	175	187	202	220	241	268	301	339
2014 Solar RFP	0	97	97	97	96	95	95	94	94	93	93	92	92	91	90
Solar Community Garden	5	9	11	13	16	19	23	27	31	37	44	52	63	76	90
Geronimo/Aurora	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Solar	4	4	4	4	4	4	3	3	3	3	3	3	3	3	3
Small Solar	16	21	25	29	34	38	44	51	59	68	80	94	111	131	156
Load Management	1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103	1,098	1,094	1,089	1,085	1,080
Existing Resources	9,846	10,004	9,999	9,969	9,913	10,164	10,177	10,151	9,772	8,627	8,383	8,104	7,803	7,814	7,846
Current Position	239	314	235	152	71	301	253	232	-165	-1,341	-1,658	-2,032	-2,510	-2,515	-2,584
All Planned Resource Additions	**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 MEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geronimo	0	0	70	69	69	69	68	68	68	67	67	67	66	66	66
Small Solar SES	-1	-1	0	1	3	4	4	4	2	4	4	4	4	3	3
Community Solar Gardens	20	36	53	72	94	103	103	102	102	101	100	100	99	98	98
Total Additional Resources	19	35	123	351	374	384	384	362	380	381	379	379	378	375	375
Forecasted Position	258	349	358	502	445	685	636	615	215	-961	-1,279	-1,653	-2,132	-2,139	-2,209
Resources Removed Due to NDPSC Decisions	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Pleasant Valley Wind	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30
Geronimo	0	0	70	69	69	69	68	68	68	67	67	67	66	66	66
2014 Solar RFP	0	97	97	97	96	95	95	94	94	93	93	92	92	91	90
Other Disallowed Resources (1)	151	151	151	139	139	168	168	143	143	143	139	106	56	50	49
Total Resources Removed	151	249	318	305	304	362	361	335	334	333	328	295	243	237	235
Forecasted Position	106	100	40	197	141	323	275	279	-120	-1,294	-1,607	-1,948	-2,376	-2,376	-2,444

(1) Other Disallowed Resources - KODA Energy LLC, WM Renewable Energy (MN Methane), Pine Bend, Jeffers Wind 20, LLC, Big Blue, Community Wind South (Zephyr), Ridgewind Power Partners LLC, Adams Wind Generations, Danielson Wind Farms, Ewington Energy Systems LLC, Grant County Wind, LLC, North Community Turbines, North Wind Turbines, Valley View Transmission, Uilk Wind Farm, Hilltop Power, Winona County Wind, Woodstock Municipal Wind LLC, Odell, Outland Solar (Slayton), Best Power (St. John's), FibroMinn, Laurentian Energy Authority, St. Paul Cogeneration

We also disagree with his recommendation that the Commission deny the requested ADP for the Mankato PPA prior to a forecasted clear deficit – in his case 2025, or 2024 based the current forecast. When all of the relevant factors are considered, the Mankato PPA beginning in 2019 is a prudent choice.

Q. WHY DO YOU STATE THE FORECASTED CAPACITY DEFICIT IS 2024 RATHER THAN 2025?

A. Mr. Polich adjusts his L&R table to remove the resources that the Commission has (or is likely to) denied. I agree with that approach. If the Commission is not going to accept a particular resource then that resource should not be included in the calculation. To do otherwise would give North Dakota credit for resources that it is not paying for. Mr. Polich removed certain resources from his L&R, but neglected to include the other resources that the Commission has not approved. When the full set of resources are removed, the need occurs in 2024.

Q. MR. POLICH CITES THE CHANGING NATURE OF NSP'S FORECASTED NEED, DO YOU CONCUR?

A. In developing his Table A and Table B, Mr. Polich accurately identifies an important point - forecasting future capacity needs is a consistently changing process. Many components that go into developing a need forecast change over time: load forecasts, MISO rules, methodology for determining the accredited capacity of current resources, and regulatory decisions regarding resources are examples. Although his assessment is sound, I disagree with portions of his analysis in Tables A and B. Unfortunately some of the data provided by the Company may have contributed to some of this confusion. The data we provided to Mr. Polich reflected forecasts and loads and resources tables that incorporated the current state of the planning "rules" at the time of the forecast. As a result, when comparing the six forecasts used in Table A, one must understand that several changes were made in both the calculations and reporting structure of the forecasts over time. Existing resources were changed from being reported as installed capacity ("ICAP") to unforced capacity using the MISO methodology ("UCAP"). The methodology of projecting future UCAP ratings, as well as the actual UCAP's of the units themselves evolved. Additionally, in earlier forecasts generic "expansion plan" units were lumped into the total resources line where in later forecasts they were not.

Specifically, the line item "2010 IRP Forecast" in Table A was created with an ICAP planning reserve margin and corresponding ICAP resource ratings. The remaining lines of the table utilize UCAP planning reserve margin and UCAP resource ratings. Therefore, a direct comparison of the "2010 IRP Forecast" line and all other Forecasts on Table A cannot be made.

In addition, the impact of MISO's 2015/2016 planning reserve margin requirement and relatively new coincident peak methodology has impacted the system need by approximately 200 MW as compared to the prior obligation planning methodology. This MISO change to incorporate a non-coincident reduction factor in 2013 largely accounts for the difference between the second through fourth forecast in Table A (Fall 2011 Forcast, Fall 2011 Forecast 2 (Case Forecast) and Spring 2013 Forecast) and the last two forecasts listed (Fall 2014 Forecast and the 2015 IRP Forecast). In conclusion, while Mr. Polich attempted to compare the Company's forecasts as they evolved over time Table A of his testimony, he did not provide the context of how the forecasts were being updated to take into account the numerous changes that were occurring with the system and the MISO rules.

Q. BEGINNING ON PAGE 14 OF HIS TESTIMONY MR POLICH RESPONDS TO THE QUESTION – "DOES TABLE 2 ON PAGE 10 OF MR. JOHNSON'S TESTIMONY USE THE MOST CURRENT FORECAST OF MISO CAPACITY OBLIGATION AND NSP'S

AVAILABLE GENERATION RESOURCES?" DO YOU AGREE WITH HIS RESPONSE?

A. No, I disagree with Mr. Polich response. The basis for Table 2 was the most current forecast of MISO capacity obligation and NSP's available generation resources at the time. Table 2 in my Direct Testimony was prepared in a way to demonstrate a System Capacity Forecast in conformance with the methodology we used to respond to Mr. Diller's IR Request DR-NDPSC-011 in Case No. PU-14-810 (Solar ADP Case).

Mr. Polich did not account for the resource adjustments shown by Table 1 above which results in a forecasted capacity need of 117 MW in 2024. This capacity need reflects resource decisions of the NPPSC, thus the removal of these resources resulting in the 117 MW capacity need in 2024. These adjustments not made by Mr. Polich explain the difference in his 149 MW capacity long position in 2024 in Table B of his testimony and Table 1 above.

Table B Line "2015 IRP Forecast**" reflects the Company's January 2015 filing of the 2016-2030 Resource Plan. Resources excluded from this position include Black Dog 6, Mankato PPA, Geronimo/Aurora, growth in Small Solar projects. Resource included this position include the 187 MW Solar portfolio, all 2013 RFP Wind projects (Pleasant Valley, Odell, Courtenay, Borders), and all previously ND disallowed PPA's subject of the last rate case PU 12-813.

Table B Line "2015 IRP Adjusted Forecast***" reflects Polich's adjustments to the line "2015 IRP Forecast" with the additions of Black Dog 6, and growth in Small Solar.

The system will benefit from the Small Solar resources, however the ND ratepayer will not be paying for these resources as agreed to by the MPUC. Small Solar is projected to grow from meeting 1.1 percent (110 MW) of system obligation in 2020 to 1.4 percent (138 MW) in 2025.

Q. ISN'T IT SUFFICIENT TO RELY EXCLUSIVELY ON THE MISO-REQUIRED RESERVES AND NOT HAVE ANY ADDITIONAL AMOUNT?

A. While the MISO reserve margin does supply some measure of risk protection, in many cases, or even typically, it may be prudent to carry excess reserves above the MISO-determined minimum level. As Mr. Haeger describes in his Rebuttal Testimony, the Company believes carrying excess reserves up to 2 to 3 percent above MISO's minimum requirements could be considered prudent if the level of shifts in capacity need experienced over the past few years continues. In addition, with the potential for new and significant impacts from the Clean Power Plan, additional MISO changes and potential for other more restrictive and costly impact on predominantly coal generation, Mr. Haeger also believes these types of circumstances and risks to the system support adding the additional 278 MW (UCAP) from the Mankato PPA is prudent and reasonable.Overall this would result in capacity long position of up to about 600 MW in some years. .

Q. WHY DOES THE COMPANY TAKE THE POSITION THAT CARRYING THE MISO-MINIMUM RESERVE MARGIN MAY BE INSUFFICIENT?

A. Because MISO annually determines reserve margin requirements, any changes in member forecasts and MISO's methodology used to determine the reserve margin requirementcould be significant. MISO's role is to analyze the system on a footprint-wide basis and doing so, relies on the forecasts provided by the member systems. MISO assumes that resources will be available as described by the utilities and that they will be available in the same manner as they have been historically. The MISO reserve margin is focused on very near term reliability – if conditions change substantially further out in time, today's reserve margin may not be sufficient to address the impact of actual changes in future customer demand and generation availability . Therefore, when planning to maintain reliability years into the future, as is required due to the long lead time to procure new resources, some measure of risk protection is prudent.

The Company believes in this time of unprecedented uncertainty in resource planning due fluctuating load and economic forecasts, evolving environmental policies, and uncertainty in MISO requirements that it is prudent to carry some additional capacity above and beyond the MISO minimum to mitigate risk.

Q. ARE THERE OTHER REASONS THAT SUPPORT SELECTING THE MANKATO PPA IN 2019?

A. Yes. The Rebuttal Testimony of Mr. Christopher Clark and Mr. Kurtis Haeger provide a summary of the benefits of installing the Mankato PPA capacity in 2019, rather than deferring a capacity addition to 2024. Under all of these circumstances, having a somewhat higher capacity long position could prove to be advantageous and is certainly prudent. Commission approval of the Mankato PPA would provide capacity price certainty and allow selection of a well-priced project with reliable gas delivery and transmission service that captures the economies of an existing gas generation site initially designed for this expansion. My testimony provides support for some of those factors.

Q. IS THE TIMING OF POWER GENERATION EQUIPMENT A RELEVANT CRITERION IN SELECTING AND DEPLOYING A RESOURCE?

A. Yes. Deploying major electric generation is a time-consuming endeavor that requires advance planning and considerable effort. It is not reasonable to wait until the need actually materializes to begin the process, because at that point it will be too late. Thus, we necessarily must rely on forecasts to determine if it is prudent to proceed with making additions to our systems, notwithstanding their potential to vary from actual outcomes.

Q. IS THE SIZE OF A UNIT A RELEVANT CRITERION ON WHETHER AND WHEN TO DEPLOY A RESOURCE?

A. Yes. It is necessary to consider resources that meet an identified need at reasonable costs overall. Economies of scale suggest that building somewhat more capacity than is entirely needed at that time to meet customer demand can be advantageous. As a result, power plant development tends to be somewhat "lumpy."

Q. WHAT DO YOU MEAN BY "LUMPY."

A. Demand growth is not smooth and will not necessarily track the most efficiently-sized power plants. For example, if a utility has an identified need of 100 MW but the most reasonable solution overall is to build a 200 MW unit, then the extra 100 MW "lump" goes beyond the nominal need. The 200 MW generator may well be the best choice even with the excess capacity as it might be more efficient and more cost-effective ov erall than deploying two-50 MW reciprocating engines or a 100 MW unit. The lumpy capacity remains available both for the system and perhaps to be sold to other utilities who may need additional capacity but want to defer building their own generation. Ultimately, load growth over time and system sales in the near term tends to absorb the extra capacity that is created by this lumpy development cycle.

Q. IS THE SELECTION OF THE MANKATO PPA CONSISTENT WITH THIS NOTION OF LUMPY DEVELOPMENT?

A. Conceptually, yes. In analyzing the costs and benefits of the Mankato PPA, it is necessary to consider the same factors of timing, cost, potential sales and ultimate use of the resource. While in this case, the Mankato PPA capacity is being deployed somewhat prior to the currently identified need, it serves those same purposes.

Q. IS PRICING OF THE RESOURCE A RELEVANT CONSIDERATION IN DECIDING WHETHER AND WHEN TO DEPLOY A RESOURCE?

A. Yes. The price is highly relevant and can influence the timing of a resource as there can be circumstances where an advantageous price justifies deploying a resource early to capture pricing benefits that might otherwise be unavailable. Similar to considerations of building extra or lumpy capacity to capture economies of scale, an advantageous price can and should influence the timing of new resources.

Q. IS THE MANKATO PPA COMPETIVELY PRICED?

A. Absolutely, on an overall basis. Typically, combustion turbine capacity is cheaper to install but more expensive to operate than combined-cycle capacity. In this instance Calpine's combined-cycle proposal was very competitively priced. Essentially, by taking the Mankato PPA the Company is able to obtain combined-cycle capacity with its more efficient and cheaper energy production at virtually the same costs for a similar amount of combustion turbine based capacity.

Q. HOW DO YOU KNOW THAT THE CALPINE PROPOSAL IS COMPETITIVE WITH A LESS-EFFICIENT COMBUSTION TURBINE?

A. In the Minnesota CAP/CON Proceeding (MPUC Docket No. E-002/CN-12-1240) in which the Mankato PPA was chosen, we received competing bids from other parties for combustion turbine capacity. Specifically, we received a bid from Invenergy to add combustion turbine capacity at a preexisting site. The evaluated cost (i.e. total system cost on a present value of revenue requirements basis) of the Invenergy combustion turbine proposal was very close to the evaluated cost of the Calpine combined-cycle. In addition, Xcel Energy proposed to install combustion turbines in Hankinson, North Dakota. The evaluated cost of that project was higher than the Calpine proposal. Finally, I reviewed industry sources for generic combustion turbine installations of the type used for modeling in our resource plan. These generic resources were generally higher priced than the bids we received in the CAP/CON Proceeding.

Thus, the Mankato PPA is highly competitive with a range of combustion turbine options that were available to us. Based on this, I conclude that the Mankato PPA beginning in 2019 is competitively priced while also providing significant optionality and flexibility benefits as described by Mr. Clark and Mr. Haeger.

Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A. Assuming the relative options remained available, the Mankato PPA would also compare favorably to a combustion turbine deployed in 2024. But then we would lose the price certainty of the Mankato PPA and the energy production efficiency and flexibility inherent with a combined-cycle unit. On balance, I conclude that it is better to lock in the price certainty and other benefits of the Mankato PPA than to wait to 2024.

III. MANKATO PPA COST IMPACTS

Q. DO YOU CONCUR WITH MR.POLICH'S TESTIMONY REGARDING THE NORTH DAKOTA RATEPAYERS COST IMPACT?

A. Generally, no. NSP agrees that using up-to-date forecast data is appropriate, and also agrees that the reference case should include the already-approved Black Dog 6 project. However, we do not agree with either the cost impacts of the project or the methodology Mr. Polich used to arrive at his figures.

Q. WHAT ARE YOUR CONCERNS WITH MR. POLICH'S CALCULATIONS?

A. My concern is that Mr. Polich appears to have estimated the cost impacts using spreadsheet adjustments of the modeling data supplied by the Company based on his understanding of the data and what each data element represented. Unfortunately his interpretation of some of the data was incorrect, leading to a flawed methodology in his calculations. The data from the Company including catagorized cost information with short generic labels. Without a full explanation of all the costs in each category, it could be somewhat difficult to interpret. Due to his interpretation the results presented in Table E are incorrect and cannot be added to the results in Table D.

As an example, Mr. Polich ultimately concludes that the Mankato project causes increased costs of over $246 million for the integrated system through 2024 (see Polich, Table F, sum of line # 3 on p. 23), yet the sum of the total fixed costs of the project for the same years is only about **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. This amount would be the highest the incremental cost could ever be, representing a highly unlikely scenario where the project was never dispatched economically at all. Any energy or capacity benefits from adding the efficient combined cycle resource to the system can only reduce the costs from there. The fact that Mr. Polich arrived at a figure almost 1.5 times the actual fixed costs demonstrates the dangers of using more simplistic methods to conduct these complex cost analyses.

Q. WHAT DO YOU BELIEVE LED TO THE ERROR IN TABLE E?

A. In developing Table E Mr. Polich cites a variable O&M avoided cost reduction value in 2019 of $46.40/MWh, which he concludes is around $40/MWh too high as compared to an actual unit's variable O&M costs. He thus makes a downward adjustment of $40/MWh for all years 2019-2024. Mr. Polich's error is that he appears to have assumed a data labeled "O&M" was variable O&M, which was incorrect. The data he is citing is actually the difference in fixed costs between modeling runs "with" and "without" the Mankato project. These fixed costs include both the the avoided capacity cost of future expansion units which are treated as purchase power agreements for modeling purposes and the "surplus capacity credit" modeling construct which is explained later. Thus, comparing this value to other thermal unit's variable O&M costs is meaningless

Additionally, Mr. Polich cites the avoided energy cost reduction value in 2019 of $69.81/MWh from the same source. He compares it to the operating characteristics of a new construction combustion turbine from our recent IRP, which he states as $57.56/MWh, and determines the cost to be higher than what would be expected. While unclear, the Company believes he determined the operating cost of the new unit from a typical calculation of "(heat rate * gas price) + variable O&M" formula.

It appears he is missing two important points. First, avoided start up costs are embedded in the Company's avoided energy cost numbers, and appear to be missing from his comparison. This can typically add at least $10/MWh to a combustion turbine's variable operating cost. Data for startup costs were not provided in the IRP, and correcting for the missing startup costs in Mr. Polich's calculation raises the IRP combustion turbine's cost quite close to the calculated avoided energy cost, erasing the discrepancy he noted.

Additionally, the interactions of the Mankato project with the rest of the Company's resources and expansion plans is highly complex. Analyses such as the overall cost/benefit of a specific resource without using a simulation tool such as the Strategist model used by the Company misses these important interactions and can lead to incorrect conclusions. Mr. Polich was attempting to use the model information he had requested to approximate costs and savings under different scenarios than the model output provided, but ultimately it is necessary to re-run the model to accurately determine those results.

Q. ON PAGE 22 OF HIS TESTIMONY, MR. POLICH EXPRESSES CONCERNS ABOUT THE VALUES USED TO POPULATE TABLE 7 OF YOUR INITIAL TESTIMONY. DO

YOU AGREE WITH THOSE CONCERNS?

A. The Company is unclear what Mr. Polich is referring to. The data used to populate Table 7 in my testimony already did take into account the partial year of operation for 2019.

Q. DID THE COMPANY UPDATE THE MODELING RESULTS BASED ON MR. POLICH'S RECOMMENDATIONS?

A. We did. The Company has modeled the costs/benefits of the Mankato project using the same methodology as in my previous testimony, except with including Black Dog 6 in the base case and using our updated 2015 IRP Strategist model.

Q. WHAT ARE THE RESULTS OF THE REVISED MODELING?

A. The overall costs/savings are as shown below in Table 1.

Table 1: Calpine Mankato Expansion PPA Overall Economics

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As can be seen, when we do the correct calculations, and only consider a "carrying"period through 2023 based on the correct Loads and Resources table, the net costs are $33 million. This is a comparable value to Mr. Polich's estimated $39 million in his Table D. Using the forecasted North Dakota load allocators, this represents about **[TRADE SECRET BEGINS TRADE SECRET ENDS]** for North Dakota customers.

Q. HOW ARE THE REVISED RESULTS COMPARABLE TO MR. POLICH'S TABLE E?

A. In developing Table E, Mr. Polich's intent was to correct the modeling for discrepancies that did not match the operating costs of physical units. A significant portion of why he noticed a discrepancy is that the modeling by the Company typically includes a credit for surplus capacity on the system. When this credit is removed from Table 1, the overall costs are $106 million. This would comparable to his calculation of $246.6 million. Using the forecasted North Dakota load allocators, this represents about $5.6 million for North Dakota customers.

Q. CAN YOU PLEASE ELABORATE ON THIS "SURPLUS CAPACITY CREDIT"?

A. The surplus capacity credit is a modeling construct the Company uses in Strategist to reflect the estimated economic value of extra length in the system. Having extra length in the system indisputably has economic value – both readily monetizable, such as providing the ability to sell a portion of excess capacity in the market, as well as a hedge against unexpected future capacity needs. It also represents the value of deferring the need to add resources on our's and our neighbor's systems in the future.

For purposes of modeling, the Company uses the estimated capacity payment for a new-build combustion turbine purchase power agreement to represent this value, recognizing that over the long-term, the costs of marginal capacity in an open market should converge to approximately this cost. The Company presents the revised economics of the Mankato project with this item delineated separately to provide greater transparency.

Q. HOW DOES THE REVISED MODELING IMPACT THE LEVELIZED COST AND RATE IMPACT CALCULATIONS PRESENTED IN YOUR DIRECT TESTIMONY?

A. Updated levelized cost and rate impact tables comparable to those presented in my direct testimony are included in Schedule A.

IV. FLEXIBILITY AND OPTIONALITY

Q. DID THE COMPANY IDENTIFY ANY OTHER BENEFITS OF THE MANKATO PPA?

A. Yes. The Mankato PPA provides value in a number of ways by providing both flexibility in optimizing the system and optionality to address uncertain and evolving circumstances. There are at least three areas where adding combined-cycle generation in 2019 adds value:

- Allows us to consider accelerating retirement of some old peakers;
- Allows us flexibility to address upcoming baseload retirements; and
- Provides optionality to defer future units in a tight capacity market.

1. Early Retirement of Peakers

Q. PLEASE DESCRIBE THE POTENTIAL TO RETIRE THE OLDER PEAKERS EARLY.

A. Adding 278 MW (accredited) of capacity in 2019 could allow us to proactively retire about 270 MW of older peakers to optimize the system, as well as providing a contingency should these older units fail prematurely, which is a possibility given their age. Retiring the older peakers would also save incremental O&M expense and ongoing capital during the 2019-2024 period. In exchange for that saving, we would obtain new combined-cycle capacity and more efficient energy production.

The addition of the Mankato PPA would enable the earlier (2019 rather tha 2024) retirement of about 270 MW of old, less efficient combustion turbine capacity with high operating costs and that, due to their age, have an increased risk of a major equipment failure and increased difficulty in finding replacement parts.

I note that Mr. Polich identified our Blue Lake, Granite Falls and French Island peakers as being slated for retirement in 2024. We agree and think it may add value to retire those peakers early if we can do so at a reasonable cost.

It should be noted that the French Island combustion turbines are not eligible for retirement before 2024, due to reliability and fuel supply contract requirements. NSP has evaluated its older combustion turbines and has determined that retiring Blue Lake Units 1-4, Granite City Units 1-4 and Wheaton Units 5 & 6 in 2019 rather than 2024 would be possible if the Mankato PPA was approved. Eliminating these older combustion turbine units in 2019 could have a material positive impact on our system, and even in the case where early retirement is not determined prudent, any one of these older units may catastrophically fail much earlier than 2024.

2. <u>Baseload Retirements</u>

Q. HOW DOES ADDING THE MANKATO PPA CAPACITY IMPACT THE RISK OF

BASELOAD RETIREMENTS?

A. Adding the Mankato PPA capacity to the system provides added flexibility in an era of increasing uncertainty over coal generation and the ongoing costs of the nuclear fleet. In the event that one or more baseload plants is retired on the Company's system in the next decade, having the Mankato PPA capacity would help avoid the higher revenue requirement (rate impact) and greater gas price risk of having to add new combined-cycle capacity.

Without the Mankato PPA's capacity available to us we may be constrained to choose more expensive or less flexible options for replacing baseload capacity.

Q. PLEASE DESCRIBE THE VALUE OF THE MANKATO PPA WITH RESPECT TO THE REDUCTION OF EXISTING BASELOAD AND INTERMEDIATE CAPACITY RESOURCES ON THE COMPANY'S SYSTEM.

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

- 2023 - Blue Lake Units 1-4 cease operation (153 MW)
- 2025 - Manitoba Hydro PPAs expire (850 MW)
- 2026 - Cottage Grove combined-cycle PPA expires (262 MW)
- 2027 - Mankato I combined-cycle contract expires (357 MW)

Further, in the 2030-2035 timeframe, the Company faces the potential retirement of three baseload nuclear units, along with Sherco Units 1 and 2 retiring after a 60 year operating life. Altogether this suggests that a significant proportion of our baseload generation may be retired within 15 to 20 years. These five generating units have been the backbone of the NSP System for many years and have formed the foundation to provide reliable service to our customers. All of these retirements and contract expirations suggest that having additional advantageously-priced combined-cycle capacity is a reasonable choice for our system.

Q. YOU MENTIONED THAT ONE OR BOTH OF SHERCO UNITS 1 AND 2 WILL POSSIBLY BE RETIRED DURING THE 2015-2030 PLANNING PERIOD. HOW DOES THE AVAILABILITY OF THE MANKATO PPA IMPACT ON THAT SCENARIO?

A. With respect to Sherco, there is the possibility that one or both of them may be retired earlier in the planning period, and we have included modeling in our 2015 Resource Plan to identify system requirements in the case that occurs. Some stakeholders have advocated for retiring a Sherco unit as early as 2021. The addition of the Mankato PPA is a hedge against that possibility.

Q. HOW DOES THE MANKATO PPA MINIMIZE THE RISK ASSOCIATED WITH EMERGING ENVIRONMENTAL REGULATIONS?

A. We continue to experience significant uncertainty surrounding environmental regulation. The EPA's existing source greenhouse gas performance standard, known as the Clean Power Plan or Section 111(d) Rules, creates significant uncertainty. While, the EPA's rules will likely to face legal challenges, it is likely that these rules will influence future action by states and their utilities, particularly if the rule is not stayed during litigation. If the Rule is not stayed, each state will draft plans and submit them to EPA by 2016 to 2018, for approval by EPA one year later; compliance will begin in 2020.

While much remains unknown, I conclude that the Clean Power Plan will (1) put increasing pressure on coal plants, possibly resulting in reduced utilization levels or additional retirements; (2) likely increase generation from existing and new natural gas plants; and (3) push us to continue adding renewable energy resources and increasing energy efficiency efforts and associated investments. The addition of the Mankato PPA hedges against these likely outcomes. It constitutes intermediate capacity that can step in to support the NSP System due to impacts the any future environmental regulation may have on our key generating facilities, including our baseload coal units at the Sherburne County Generating Station and our Allen S. King Plant.

V. CAPACITY RISKS

Q: MR. POLICH TESTIFIES ABOUT CAPACITY RISKS AS ONE REASON WHY HE RECOMMENDS DENYING THE ADP. WHAT ARE THE CAPACITY RISKS YOU SEE WITH THE MANKATO PPA BEING APPROVED OR NOT BEING APPROVED BY THE COMMISSION?

A. Mr. Polich concludes that approving the Mankato PPA creates the risk of excess capacity on the system. He does not focus on the risks inherent in the Commission not granting the ADP. This section of my Rebuttal Testimony addresses those risks. The risks of not granting the ADP for the Mankato PPA include:

1. Miss out on locking in a low cost combined-cycle capacity resource now, recognizing that there a no costs to NSP customers until June 2019 and exposing NSP customers to higher cost capacity if we wait until 2024 to obtain new capacity.

2. Rejection of the Mankato PPA could result in this capacity not being available to North Dakota customers and exposing North Dakota customers to higher cost capacity in 2024 which could even be a much smaller (50 MW) dedicated gas generation unit or other purchases which could have substantially higher costs than those of the Mankato PPA.

3. The Mankato PPA has low operating costs and provides substantial power supply management benefits.

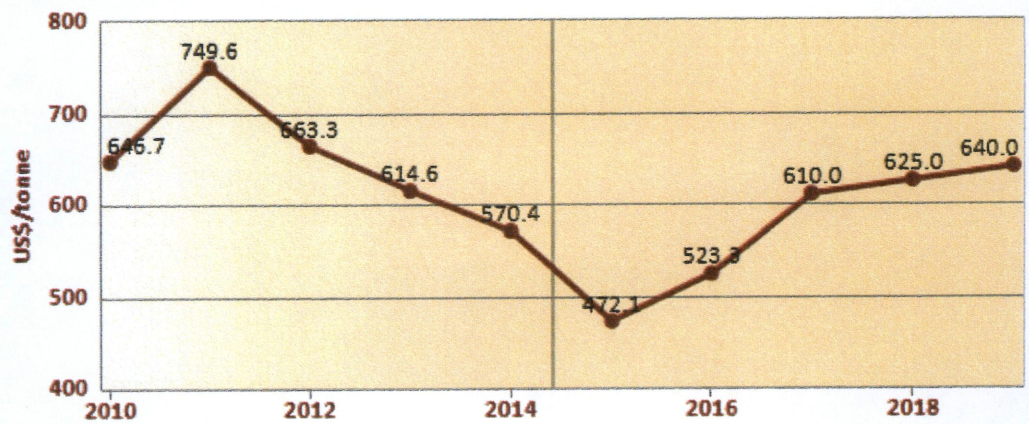
Q: ARE THERE TECHNOLOGY RISKS ASSOCIATED WITH APPROVING THE PPA AT THIS TIME?

A: There are several capacity risks including the risk of gas generation equipment dramatically increasing in cost. This is a real possibility – we have projected that costs of natural gas power generation equipment will rise due to increased competition from the need to replace older and/or non-economic coal and gas generation that is projected to being retired in the coming decade. Such a situation occurred in the early 2000s when demand for gas generation equipment spiked resulting in substantial costs being charged for slots in turbine manufacturing queues. There is a real chance that this could happen again in the near future with significant amounts of expected coal unit retirements arising from increased environmental regulation as well as economic and age-related factors.

Q. CAN YOU GIVE AN EXAMPLE OF THE TYPES OF COSTS THAT COULD CONTRIBUTE TO THE INCREASE OF COMBINED-CYCLE CAPACITY IN THE FUTURE?

A. Yes. A contributing factor to project cost is the price of steel. Currently, the price of steel has reached a new 10 year low at $472 per ton. But, that will likely change, as shown by Figure 4 which shows a historical and forecasted per ton steel prices for 2010 through 2019. With steel being an important component of a gas generation project, the significant cost increase would be reflected in higher project costs if the Company decided to wait.

Figure 4: 2010-2019 Steel Prices (US$/ton)



Source: EIU Economic and Commodity Forecast, July 2015

Given this information, it seems prudent and in the best interests of NSP customers to lock into the competitively priced Mankato PPA now to avoid higher future PPA and project pricesdue to dramatic forecasted increase in steel prices over the next four years. If the average annual increase of about 9 percent per year over the 2015-2019 period continues into the future, by 2024 steel prices would be $985 per ton, a 109 percent increase in price from 2015 steel price level.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. While the Company appreciates Mr. Polich's analysis and opinions, we believe that, on balance, proceeding with the Mankato PPA in 2019 is a reasonable and prudent resource choice. While this capacity addition falls somewhat before our need, the balance of factors described in my testimony support including this resource in our supply portfolio.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SCHEDULE A

Table A1: Levelized Cost Analysis--$/MWh

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

To provide greater transparency, the same information as shown in Table A1 is shown below in Table A2 with the costs and savings itemized in detail.

Table A2: Detailed Breakout of Levelized Cost Analysis--$/MWh

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Table A3: NSP Ratepayer Cost Impacts of Mankato PPA (ND Assumptions)

	NET RATE COST/(SAVINGS)				
	2019	2020	2021	2022	2023
Impact of Mankato PPA ($/MWh)	($0.13)	$0.14	$0.34	$0.25	$0.18
Fall 2014 Sales Forecast, MWh	42,708,090	42,860,052	42,822,135	43,003,977	42,974,865
Annual Cost/(Savings) of Mankato PPA	($5,762,193)	$5,910,569	$14,493,239	$10,856,273	$7,948,317
Total 2019-2023 Cost/(Savings)					$33,446,204

Table A4: NSP Ratepayer Cost Impacts of Mankato PPA (Without Surplus Capacity Credit)

	NET RATE COST/(SAVINGS)				
	2019	2020	2021	2022	2023
Impact of Mankato PPA ($/MWh)	$0.27	$0.55	$0.56	$0.56	$0.55
Fall 2014 Sales Forecast, MWh	42,708,090	42,860,052	42,822,135	43,003,977	42,974,865
Annual Cost/(Savings) of Mankato PPA	$11,370,026	$23,442,769	$23,785,133	$24,145,523	$23,580,054
Total 2019-2023 Cost/(Savings)					$106,323,505

Table A5: ND Ratepayer Cost Impacts of Mankato PPA (ND Assumptions)

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Table A6: NSP Ratepayer Cost Impacts of Mankato PPA (Without Surplus Capacity Credit)

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Table A7: Annual Rate Impact

CALPINE - ND Assumptions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Base Rates	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.041¢/kWh	0.070¢/kWh	0.071¢/kWh	0.072¢/kWh	0.073¢/kWh	0.073¢/kWh	0.074¢/kWh
Fuel Clause	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.029¢/kWh	0.060¢/kWh	0.069¢/kWh	0.061¢/kWh	0.053¢/kWh	0.047¢/kWh	0.052¢/kWh
Avoided Fuel & Purchased Power	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	-0.083¢/kWh	-0.117¢/kWh	-0.106¢/kWh	-0.108¢/kWh	-0.107¢/kWh	-0.103¢/kWh	-0.108¢/kWh
Net Rate Impact	**0.000¢/kWh**	**0.000¢/kWh**	**0.000¢/kWh**	**0.000¢/kWh**	**(0.013¢/kWh)**	**0.014¢/kWh**	**0.034¢/kWh**	**0.025¢/kWh**	**0.018¢/kWh**	**0.018¢/kWh**	**0.018¢/kWh**
CALPINE - Re-Priced	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Base Rates	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.041¢/kWh	0.070¢/kWh	0.071¢/kWh	0.072¢/kWh	0.073¢/kWh	0.073¢/kWh	0.074¢/kWh
Fuel Clause	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.029¢/kWh	0.060¢/kWh	0.069¢/kWh	0.061¢/kWh	0.053¢/kWh	0.047¢/kWh	0.052¢/kWh
Avoided Fuel & Purchased Power	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	-0.043¢/kWh	-0.076¢/kWh	-0.085¢/kWh	-0.077¢/kWh	-0.071¢/kWh	-0.093¢/kWh	-0.134¢/kWh
Net Rate Impact	**0.000¢/kWh**	**0.000¢/kWh**	**0.000¢/kWh**	**0.000¢/kWh**	**0.027¢/kWh**	**0.055¢/kWh**	**0.056¢/kWh**	**0.056¢/kWh**	**0.055¢/kWh**	**0.028¢/kWh**	**(0.008¢/kWh)**

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

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

Case No. PU-15-96

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

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

Paul B. Johnson

Paul B. Johnson

Subscribed and sworn to before me this 11th day of September, 2015.

James G. Erickson
Notary Public
Minnesota
My Commission Expires January 31, 2019

Notary Public
My Commission Expires: Jan. 31, 2019