DIRECT TESTIMONY AND SCHEDULE
PHILIP JOSEPH "P.J." MARTIN

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY
ADVANCE PRUDENCE – ACQUISITION OF THE 375 MW MANKATO ENERGY CENTER AND THE 345 MW MANKATO ENERGY CENTER II

CASE NO. PU-18-___

Resource Planning Testimony

Exhibit ___ (PJM-1)

December 7, 2018

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Prefiled Direct Testimony of Phillip Joseph Martin
Northern States Power Company
Zeviel Simpser, Briggs and Morgan, P.A.

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

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

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

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

Prior to joining Xcel Energy, I worked as a Portfolio Director and Energy Trader at ACES Power Marketing. In these roles, I engaged in trading and wholesale portfolio management activities on behalf of electric cooperatives, municipal utilities, IPPs, banks, and other customers. I also supported long-term planning and risk management efforts for these customers in the Midcontinent Independent System Operator, Inc., PJM Interconnection, LLC, SERC, and other markets across the U.S.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. In my current role, I am responsible for the direction of electric resource planning for the five-state integrated Northern States Power Company system (NSP System), which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. This includes assisting the

Company in making reasonable and prudent acquisition decisions for electric generation resources. Among other things, I oversee our resource planning efforts using Strategist to conduct economic evaluations of potential resource additions, and oversee bid processes for new resource acquisitions.

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

A. The purpose of my testimony is to discuss the Company's proposed acquisition of the 375 MW Combined Cycle Mankato Energy Center I (MEC I) and the 345 MW Combined Cycle expansion project (MEC II) (collectively, the MEC Facility) that is scheduled to go in-service in June of 2019. My testimony details the components and prudence of the purchase price of the MEC Facility and the economic analysis supporting the transaction. I support the conclusion that the North Dakota Public Service Commission (Commission) should grant an advance determination of prudence (ADP) for the MEC I and MEC II transactions.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. My testimony covers the following topics:

- Purchase Price of the MEC Facility; and
- Economic Analysis of the Transaction.

II. PURCHASE PRICE OF THE MEC FACILITY

Q. PLEASE BRIEFLY DESCRIBE THE PROPOSED TRANSFER OF OWNERSHIP OF THE MEC FACILITY.

A. At a high level, Xcel Energy will be purchasing the LLCs that presently own MEC I and MEC II, including a series of upgrades that have been undertaken on these facilities, with a series of risk mitigation agreements to ensure customers get the full benefit of the acquisition and the facility. Company witness Ms. Bria Shea provides additional detail regarding the transaction itself.

Q. WHAT IS THE TOTAL PURCHASE PRICE FOR THE MEC I AND MEC II TRANSACTION?

A. The total purchase price for this transaction is $650 million, which is about $100 million more than the present value of the Company's capacity payment obligations under the MEC I and MEC II power purchase agreements (PPAs).

Q. IS THE PURCHASE PRICE PRUDENT?

A. Yes.

Q. PLEASE EXPLAIN.

A. Several factors contribute to demonstrating the prudence of the purchase price. Most importantly, the pricing of the proposed transaction is close to our estimate of Southern Power's total investment in the plant and is consistent with other combined cycle transactions of similar size which provides a reasonable reference point for evaluating the purchase price of this transaction.

Q. PLEASE DETAIL THE COMPONENTS OF THE TOTAL PURCHASE PRICE.

A. With respect to MEC I and MEC II, the Company estimates that Southern Power will have invested approximately $609 million to $622 million in both units of the MEC Facility upon completion of the expansion associated with MEC II. This approximate investment includes Southern Power's acquisition of MEC I and the expansion rights associated with MEC II for $395 million in 2016; upgrades to the MEC I combustion turbine in 2017 for approximately $31 million; and an investment of approximately $180 million in total capital in the MEC II expansion and general facility upgrades.

Beyond MEC I and MEC II, the purchase price includes the value of inventory at the plant (valued at approximately $4 million); L-0 turbine blades for the steam turbine currently on order (valued at approximately $4 million); and the market value of the long-term water supply agreement with the City of Mankato, which the Company has valued at approximately $18 million through the life of the facility when compared to procuring reclaimed water from the City of Mankato without the benefit of the existing contract. Southern Power also recently upgraded a number of facilities at the plant, including the control room, employee meeting and break areas, and facility lighting at the plant.

Q. IS THE PURCHASE PRICE FOR THE FACILITY CONSISTENT WITH OTHER SIMILAR TRANSACTIONS THAT HAVE OCCURRED IN THE REGION?

A. Yes. The purchase price for the MEC Facility is comparable to other combined cycle purchases the Company has seen in this region. For comparison purposes, the MEC $650 million purchase price for 760 MW CC breaks down to $855/kW. Ownership of the MEC Facility will afford the Company access to the full installed capacity of the 760 MW plant, whereas the existing PPAs only entitle the Company to 720 MW of total installed capacity.

Q. PLEASE DETAIL THE OTHER RECENT CC SALE TRANSACTIONS OR PROPOSALS IN THIS REGION THAT ARE COMPARABLE TO THE MEC FACILITY TRANSACTION.

A. First, the Riverside Energy Center, which was originally constructed at 600 MW in 2004 and later sold to Wisconsin Power and Light with expansion nearing completion that will bring its total capacity to 1,330 MW, was purchased at an average price of $827/kW.

Second, the Fox Energy Center, which was originally constructed at 619 MW in 2005 and later sold to Wisconsin Public Service Company, with a proposed expansion that would have brought its total capacity to 1,094 MW, was purchased at an average price of $875/kW.

Third, the 525 MW Nemadji Trail Energy Center transaction was proposed by Minnesota Power at a proposed price of $1,333/kW.

I highlight the Riverside and Fox transactions because they involved original equipment of the same vintage as MEC I with a subsequent facility expansion.

Q. HAS ANYTHING OCCURRED RECENTLY THAT WOULD IMPACT THE PURCHASE PRICE OF THE RIVERSIDE AND FOX TRANSACTIONS?

A. Yes. Both transactions were executed several years ago, before the passage of the 2017 Tax Cuts and Jobs Act (TCJA). The federal corporate tax rate reduction resulting from the TCJA immediately enhanced the value of power plants with PPAs in place due to the reduced federal tax rate compared to the period in which those PPAs were structured. For Riverside and Fox, the purchase price achieved in today's tax environment would likely be greater than achieved at the time of their sale several years ago. In the same vein, the value of the MEC I and MEC II contracts in the market have likely increased since the facilities were acquired in late 2016.

III. ECONOMIC ANALYSIS OF THE TRANSACTION

Q. HOW DID THE COMPANY EVALUATE THE COST-EFFECTIVENESS OF THE MEC FACILITY TRANSACTION?

A. The Company principally used the Strategist resource planning model (Strategist) to aid in its economic analysis.

Q. WHAT IS STRATEGIST?

A. Strategist is a modeling program that simulates the operation of the NSP System and estimates the total cost of energy over the life of a project on a present value basis. Strategist can be used to test results under a range of input assumptions, also known as sensitivities. The Company uses this tool, which is industry standard, for the majority of its resource planning efforts.

Q. HOW DID THE COMPANY USE STRATEGIST TO ANALYZE THE MEC I AND MEC II TRANSACTIONS?

A. For this analysis, the Company simulated the operation of the NSP System through 2057 and compared system costs of Company ownership of the MEC Facility to system costs when the output of the MEC Facility is purchased under the existing PPAs. This analysis indicates that customers are expected to realize some savings under Company ownership.

Q. WHAT BROAD CONCLUSIONS CAN BE DRAWN FROM THE COMPANY'S ECONOMIC ANALYSIS OF THE PROPOSED TRANSACTION?

A. I conclude that the proposed transaction is cost effective, with overall system costs being lowered, on a present value of revenue requirements (PVRR) basis, over the life of the MEC Facility with Company ownership than without it. This analysis is validated through the several scenarios and different cases utilized by the Company to perform its economic assessment. Table 1, below, provides high-level results of the Company's economic analysis.

Table 1: Overall PVRR Savings

	Total PVRR Savings
Modified IRP Scenario	$142 million
85-by-30 Scenario	$66 million

Q. IN GENERAL, WHAT IS THE SOURCE OF THE SAVINGS ASSOCIATED WITH THE TRANSFER OF OWNERSHIP?

A. As explained above, the Strategist economic modeling analysis compares costs under the existing PPAs to costs under the ownership proposal. The cost savings under the ownership proposal are achieved by avoiding the costs that would be incurred under the existing PPAs as well as utilizing the MEC Facility resource over a longer service life.

Q. WHAT SCENARIOS DID THE COMPANY MODEL?

A. To assess and confirm the benefits of the transfer of ownership under a range of potential outcomes, the Company modeled two different expansion plan scenarios: the *Modified IRP* and *85-by-30 Plan* scenarios. Table 2 shows the total nameplate additions in MW from 2019-2030 under each scenario.

Table 2: 2019-2030 Total Capacity Additions by Scenario (MW)

	Modified IRP	**85-by-30 Plan**
Mankato Owned	762	762
Sherco CC	835	835
Greenfield CC	0	0
Greenfield CT	642	0
Brownfield H CT	642	0
Brownfield F CT	0	0
Wind Additions	2,212	2,962
Solar Additions	1,462	6,462
Total Additions	6,555	11,021

Q. PLEASE DESCRIBE THE *MODIFIED IRP* SCENARIO.

A. The *Modified IRP* scenario presents an evaluation of the proposed transaction within the context of the previous resource plan. In other words, the *Modified IRP* scenario provides an analysis of the transfer of ownership using resource assumptions consistent with a reference case that reflects an update from the outcome of the Company's last resource planning cycle. The Strategist modeling conducted for the MEC Facility also includes the most recent load forecast, fuel price forecasts, and updated pricing for renewable resources, among other assumptions including approximately 4 GWs of nameplate wind resources. Table 3 identifies the expansion plan for this scenario.

Table 3: Modified IRP Scenario Expansion Plan – Company Ownership

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Firm Capacity														
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	627	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	728	0	0	0	0
Greenfield CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greenfield CT	0	0	0	0	0	0	0	0	0	0	0	0	642	0
Brownfield H CT	0	0	0	0	0	0	0	0	0	321	0	0	321	0
Brownfield F CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nameplate Capacity														
Wind	0	1,155	400	300	0	126	0	20	21	67	35	80	8	206
Solar	0	0	0	0	0	412	304	197	147	0	402	0	0	0

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Firm Capacity														
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greenfield CC	0	844	0	844	0	0	0	0	0	0	0	0	0	0
Greenfield CT	0	0	321	0	0	0	642	321	0	642	321	0	0	0
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield F CT	200	0	200	0	0	0	0	0	0	0	0	0	0	0
Nameplate Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	87	379	113	29	334	7	0	6	142	181	183	0	79	38
Solar	0	0	0	0	29	0	0	0	0	0	323	236	126	25

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	Total
Firm Capacity													
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	627
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	0	728
Greenfield CC	844	0	0	844	0	0	0	0	0	0	0	0	3,376
Greenfield CT	0	0	321	0	0	0	0	321	321	0	321	0	4,173
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	642
Brownfield F CT	0	0	0	0	0	0	0	0	0	0	0	0	400
Nameplate Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	-44	-48	0	0	0	0	0	0	0	0	0	0	3,903
Solar	0	0	0	0	0	0	0	0	0	0	0	0	2,201

Q. WHAT IS THE FOUNDATION OF THE *85-BY-30 PLAN* SCENARIO?

A. In late 2017, Xcel Energy's CEO, Ben Fowke, presented the Company's plan to achieve aspirational carbon reduction goals by 2030 by generating 60 percent of NSP's generation from renewable resources and 85 percent of NSP's generation from carbon-free resources. The Company has since affirmed its commitment to achieve 85 percent of our generation from carbon-free sources by 2030 in other forums.

Q. PLEASE DESCRIBE THE *85-BY-30 PLAN* SCENARIO.

A. The Company included the *85-by-30 Plan* scenario to evaluate the proposed transfer of ownership under a scenario consistent with Xcel Energy's 85 percent goal. The *85-by-30 Plan* reflects renewable expansion that the Company believes will help achieve carbon reduction goals. This scenario includes more solar by 2030, resulting in 60 percent of generation coming from renewable resources. This scenario also dispatches the A.S. King plant on an economic basis beginning in 2028 rather than its current must-run status to accommodate the much higher levels of renewables. It should be noted, however, that the *85-by-30 Plan* scenario does not fully achieve, without other system changes, 85 percent carbon free generation by 2030 but rather only gets to about 79 percent. The renewable expansion through 2057 under the *85-by-30 Plan* scenario is shown, below, in Table 4:

Table 4: 85-by-30 Plan Scenario Expansion Plan – Company Ownership

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Firm Capacity														
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	627	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	728	0	0	0	0
Greenfield CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greenfield CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield F CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nameplate Capacity														
Wind	0	1,155	400	300	0	876	0	20	21	67	35	80	8	206
Solar	0	0	0	0	0	412	1,304	197	1,147	1,000	1,402	0	1,000	0

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Firm Capacity														
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greenfield CC	0	0	0	0	0	0	0	0	0	844	0	0	0	0
Greenfield CT	0	0	0	321	0	321	321	321	0	0	0	0	0	0
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield F CT	0	0	200	0	0	0	0	0	0	0	0	0	0	0
Nameplate Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	87	379	113	29	334	7	0	6	892	181	183	0	79	38
Solar	0	500	0	1,000	29	0	500	0	0	0	323	736	126	25

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	Total
Firm Capacity													
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	627
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	0	728
Greenfield CC	0	0	0	844	0	0	0	0	0	0	0	0	1,688
Greenfield CT	321	0	321	0	0	0	0	0	321	0	0	321	2,568
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield F CT	0	0	0	0	0	0	0	0	0	0	0	0	200
Nameplate Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	-44	-48	0	0	0	0	0	0	0	0	0	0	5,403
Solar	0	0	500	0	0	0	0	0	0	0	0	0	10,201

Q. DO THE OWNERSHIP SCENARIOS DEMONSTRATE A CAPACITY NEED FOR BOTH MEC I AND MEC II IN THE NEAR TERM?

A. Yes. Owning both MEC I and MEC II results in the MEC Facility asset remaining on the system for a substantially longer period of time than allowed by the current MEC PPAs, as the Company expects to be able to use MEC I through 2046 and MEC II through 2054. The MEC Facility asset will therefore be available to meet capacity needs that arise resulting from the upcoming expiration of several PPAs, including the expiration of the Manitoba Hydro and Cannon Falls PPAs in 2025 and the MEC I and Cottage Grove PPAs in 2026.

Additionally, the mid-2020s capacity need identified in the Company's 2015 MEC II ADP application still exists due to scheduled PPA expirations and plant retirements.

I note that due to this, the MEC II component of the proposed transaction differs from the PPA ADP request dismissed without prejudice by the Commission in Case No. PU-15-96. This is because while the need for the facility is still several years out, customers will have the benefits of the MEC Facility for a significantly longer period – more than double the amount of time than the PPA term.

Q. WILL THE MEC FACILITY TRANSACTION IMPACT THE COMPANY'S COMMITMENT TO LOCATE A NATURAL GAS PLANT IN NORTH DAKOTA BY THE END OF 2025?

A. No. The Company does not believe its commitments to locate a natural gas-fired plant in eastern North Dakota will be materially impacted by the proposed transaction. The Company's net capacity position assuming no new capacity resources are added other than the Mankato resource via the ownership option and the Sherco Combined Cycle will be in deficit in 2026, supporting the procurement of a combustion turbine in North Dakota to meet that need in as early as 2025.

I note that if the Company did not acquire the MEC Facility, Xcel Energy would still be committed to the MEC I PPA until 2026 and the MEC II PPA for 20 years after the in-service of the facility. Consequently, the need drivers for the 2025 combustion turbine in eastern North Dakota are not impacted by the proposed transaction. To that end, the current application is more related to the prudence of the proposed ownership structure rather than a more traditional analysis for a resource addition.

Q. WHAT WAS THE RESULT OF THE ECONOMIC ANALYSIS PERFORMED USING THE STRATEGIST TOOL?

A. The analysis indicates that the transfer of ownership proposal results in net savings for our customers under all sensitivity tests conducted, consistent with the "least cost" requirements of the Commission's planning paradigm, discussed in more detail in the Direct Testimony of Company witness Ms. Bria Shea. As already noted, significant benefits are due to the offset of the costs under the existing PPAs as well as the benefits of utilizing the MEC Facility beyond its current PPA term. Tables 5 and 6, below, categorize the costs under the *Modified IRP* and *85-by-30 Plan* scenarios. Both tables show the net present value of the full modeling period (2018-2057) on a PVRR basis.

Table 5: PVRR Savings from Modified IRP Scenario

	PVRR
Capital Cost of Mankato Purchase	915
Fixed Savings of Mankato PPA	(555)
Fixed Cost/Expansion Plan Cost/(Savings)	(359)
VOM Cost/(Savings)	(47)
Fuel Cost/ (Savings)	21
Market Cost/(Savings)	(71)
PPA Starts/Own Start Fuel Cost/(Savings)	(46)
Total Cost/(Savings)	(142)

Table 6: PVRR Savings from 85-by-30 Plan Scenario

	PVRR
Capital Cost of Mankato Purchase	915
Fixed Savings of Mankato PPA	(555)
Fixed Cost/Expansion Plan Cost/(Savings)	(365)
VOM Cost/(Savings)	(28)
Fuel Cost/ (Savings)	13
Market Cost/(Savings)	(6)
PPA Starts/Own Start Fuel Cost/(Savings)	(39)
Total Cost/(Savings)	(66)

Q. WHAT DO THESE TABLES SHOW?

A. The proposed transfer of ownership results in cost/savings impacts in a number of different areas.

- Significant fixed cost savings are derived from avoided demand charges under the existing PPAs;
- Sizeable Fixed Expansion Plan Cost savings are also generated from the avoided fixed costs of procuring replacement capacity after the existing PPAs expire.
- Some variable O&M and start costs are avoided due to the structure of the PPAs compared to Company ownership.
- Fuel costs increase slightly due to increased reliance on MEC to offset market purchases. Under an *85-by-30 Plan* future, the ability to offset market purchases is significantly reduced.

Q. WHAT ASSUMPTIONS DID THE COMPANY MAKE IN DEVELOPING THIS ANALYSIS?

A. The assumptions for the economic assessment of the proposed transfer of ownership are based on the Company's most recent resource planning cycle. But, given the passage of time, the expansion plan has been updated to reflect the Company's most recent wind investments and other changed circumstances.

A detailed description of the Strategist assumptions is included in Schedule 1 to my Direct Testimony.

Q. DID THE COMPANY MODEL SENSITIVITIES IN DEVELOPING THE ANALYSIS?

A. Yes. Given the uncertainty associated with many of the key assumptions, the Company also modeled a number of sensitivities to test the benefits of the proposed transfer of ownership under a range of potential outcomes, consistent with the Commission's resource planning philosophies. These sensitivities include natural gas prices, forecasted load, Markets-Off, and ongoing MEC costs. I describe in more detail each of these sensitivities below.

Q. PLEASE DESCRIBE THE NATURAL GAS PRICES SENSITIVITIES.

A. Our natural gas price forecast is based on a blend of the latest market information and long-term fundamentally-based forecasts acquired from third parties. We have included a low and high gas price sensitivity to evaluate the impacts of variations in gas prices on the proposed transfer of ownership.

Q. PLEASE DESCRIBE THE FORECASTED LOAD SENSITIVITIES.

A. The modeling incudes the most recent load forecast, which was developed in the fall of 2018. The high and low load sensitivities were developed by increasing and decreasing forecasted load one standard deviation from the median forecast.

Q. PLEASE DESCRIBE THE MARKETS-OFF SENSITIVITIES.

A. In this sensitivity, the model does not allow market purchases and sales. Thus, the cost-effectiveness of resource additions are based on their effectiveness in serving only NSP System needs. Because the markets-off sensitivity does not allow market purchases or sales, any generation in excess of system requirements is categorized as "dump energy." We have included sensitivities that give a reduced value of 50 percent of the forecasted LMP to any dump energy and a sensitivity that gives no value to dump energy.

Q. PLEASE DESCRIBE THE ONGOING MEC COSTS SENSITIVITIES.

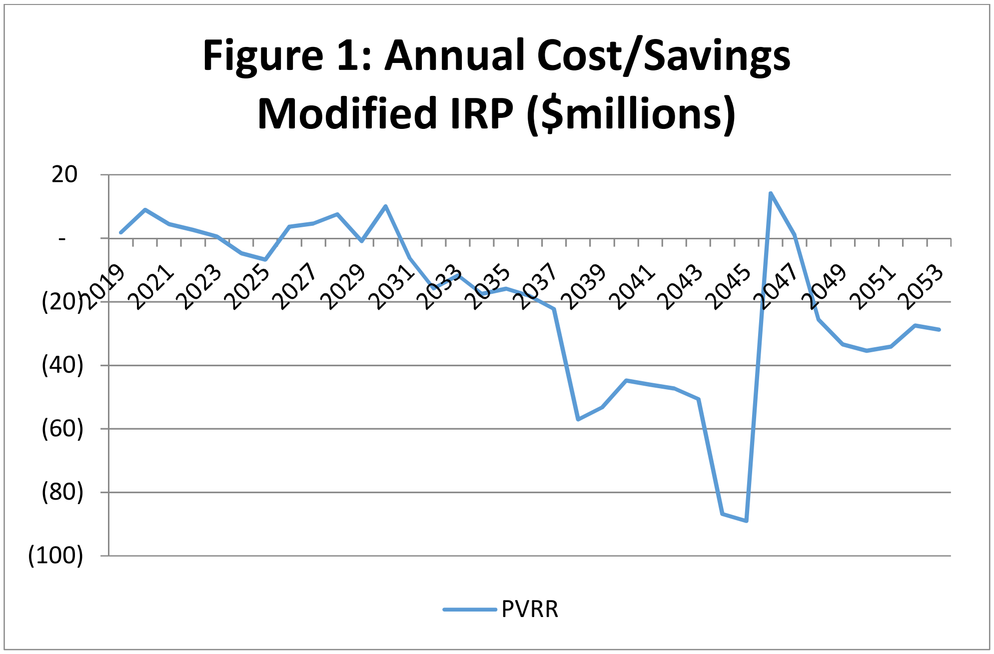
A. Ongoing costs at MEC are assumed to escalate at a rate of approximately two percent annually. The low and high sensitivities test annual escalation rates of one percent and three percent, respectively.

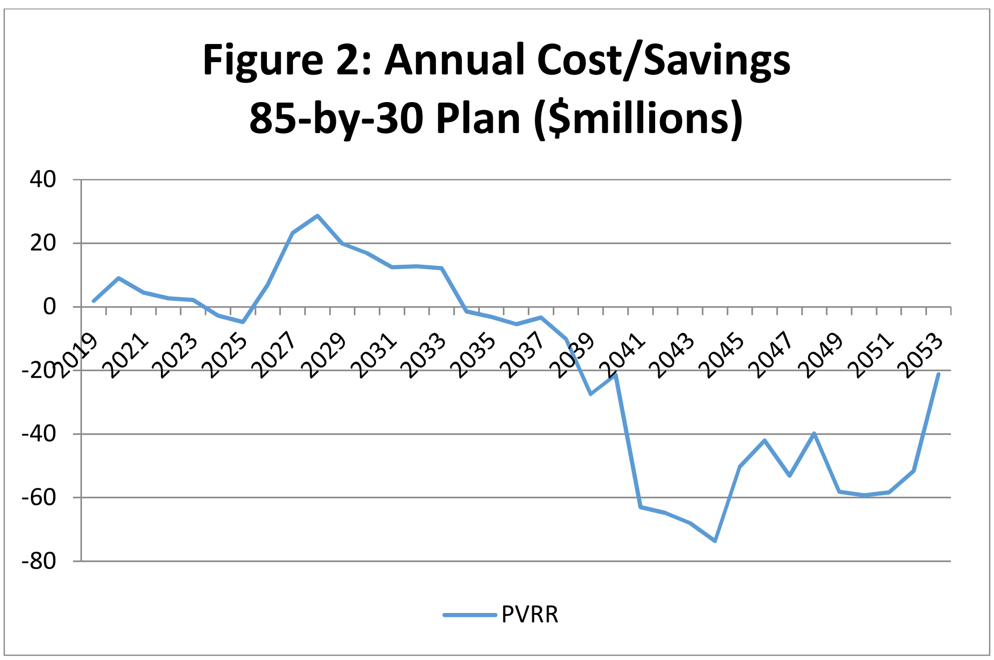
Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A. I conclude that the transfer of ownership proposal will provide cost savings to the NSP System in a number of different areas over the life of the MEC Facility.

Q. DID THE COMPANY ANALYZE HOW THESE COST SAVINGS EVOLVE OVER THE LIFE OF THE TRANSACTION?

A. Yes. To understand how the costs (savings) change over time, Figures 1 and 2 below visually portray the annual costs (savings) impacts of the transfer of ownership relative to the existing PPAs under both scenarios.





Q. WHAT ASSUMPTIONS DID THE COMPANY USE IN CREATING THE ABOVE FIGURES?

A. As mentioned previously, the assumptions for the economic assessment of the proposed transfer of ownership should be largely consistent with the assumptions that will be used in our next resource planning process. We have used updated load forecasts, fuel price forecasts, resource cost assumptions, etc. to reflect our most up-to-date expectations for key variables in our modeling efforts. Ownership was assessed under two scenarios which are intended to help serve as two bookends to frame the potential benefits of the transaction under two very different potential paths. The *Modified IRP* scenario represents a business as usual approach with marginal renewable and carbon free resource additions whereas the *85-by-30 Plan* scenario represents a rapid carbon reduction approach with significant renewable additions. A detailed description of the Strategist assumptions is included in Schedule 1 to my Direct Testimony.

Q. WHAT DO FIGURES 1 AND 2 DEMONSTRATE?

A. The benefits of the transfer of ownership increase in the early 2030s, when the MEC Facility can be relied on for economic capacity and energy as the nuclear units are retired. Prior to the early 2030s, the PVRR comparison of ownership to the existing PPAs shows approximately equal annual savings.

Q. SPECIFIC TO FIGURE 2, WHAT IS CAUSING THE SLIGHT INCREASE IN ANNUAL COSTS FROM THE MID-2020S TO THE EARLY 2030S?

A. The assumptions made for the *85-by-30 Plan* scenario result in considerable levels of surplus portfolio capacity length in the mid-2020s to early 2030s. The costs of carrying this surplus capacity are key drivers in the increase in annual costs displayed in Figure 2, above. However, the Company expects to be able to utilize MEC I through 2046 and MEC II through 2054, increasing the benefits to customers over a longer period as compared to the PPAs. Figures 3 and 4, below, show the amount of surplus net capacity associated with both the *Modified IRP* and *85-by-30 Plan* scenarios under both ownership and existing PPA structures.

Figure 3: Net Capacity Position with Ownership (MW)

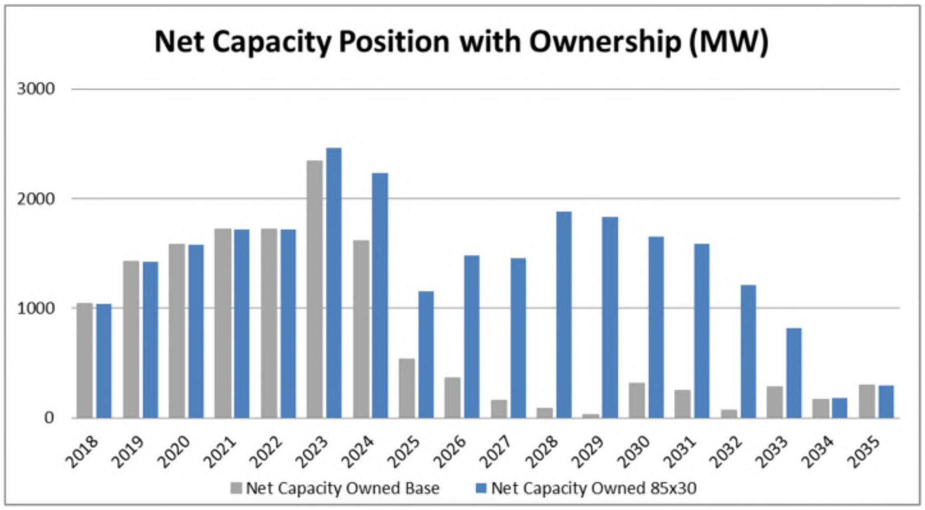
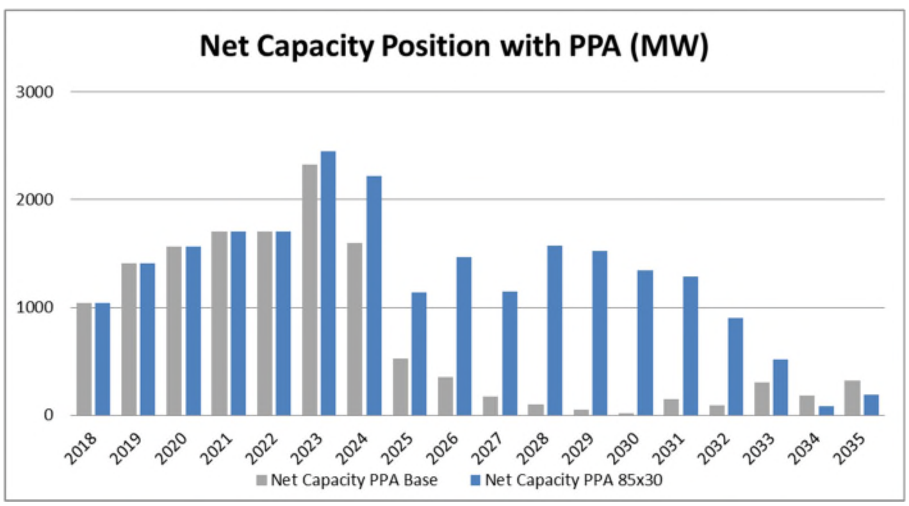


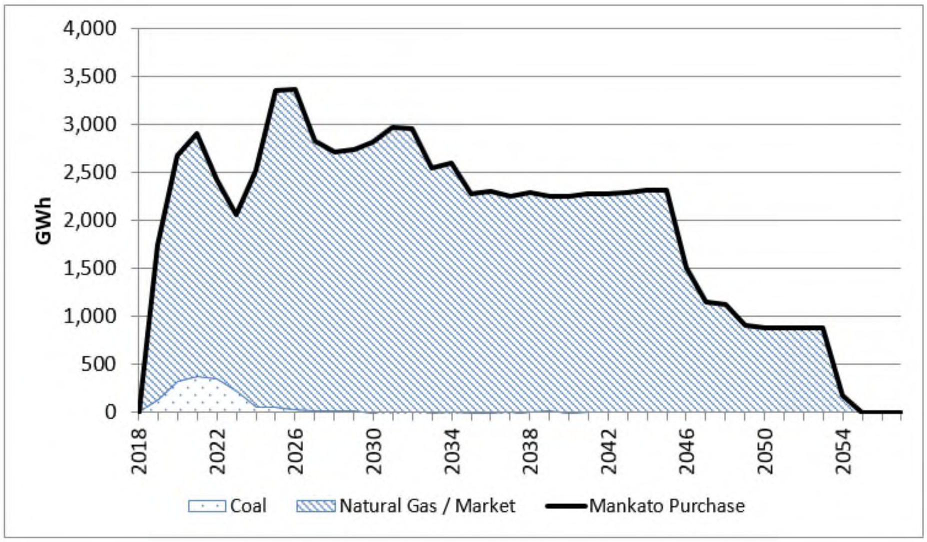
Figure 4: Net Capacity Position with MEC PPA (MW)



Q. WHAT GENERATION AND/OR MARKET PURCHASES ARE DISPLACED BY AN OWNED MEC RESOURCE UNDER THE *85-BY-30 PLAN* SCENARIO?

A. While some coal is displaced in the near-term the energy from the MEC Facility primarily displaces natural gas and market purchases. As a combined cycle, MEC is more efficient than combustion turbines or older CCs and mitigates the risk of greater market purchases in the future. Figure 4, below, shows the generation and/or market purchases that are displaced by the Company's ownership of the MEC Facility under the *85-by-30 Plan* scenario.

Figure 4: Displaced Energy (GWh)



Additionally, relatively more energy is assumed to be displaced under Company ownership, due to the expected additional capacity of the MEC Facility that was not contemplated under the existing PPAs. As a dispatchable resource, generation from the MEC Facility will offset higher cost and less efficient generation.

Q. WHAT IS THE ESTIMATED IMPACT OF THE TRANSFER OF OWNERSHIP ON THE RATES PAID BY THE COMPANY'S NORTH DAKOTA CUSTOMERS?

A. Based on the results of the Company's Strategist modeling, the Company expects a slight increase for residential customers during the early years of ownership due to the purchase as compared to the PPA. The Company then expects that beginning in 2024, the cost of ownership will more than offset due to avoiding costs that would be incurred under the existing PPA as well as utilizing the MEC Facility over a longer service life.

Q. PLEASE EXPLAIN HOW YOU REACHED THAT CONCLUSION.

A. To develop the rate impacts analysis, the Company began with the incremental impacts of owning the MEC Facility as determined by the Strategist modeling that was conducted. Specifically, the Company used the PVRR sensitivity outputs from the *85-by-30 Plan* scenario, as the Company believes that this scenario most closely reflects the impacts to customer bills.

Using the annual system-wide costs impact from Strategist, the Company then applied a jurisdictional allocator based on a current sales forecast to determine the costs allocated to the North Dakota jurisdiction. The jurisdictional costs were then allocated to classes based on Class Cost of Service Study allocation factors approved in the Company's last North Dakota rate case order.

Q. HOW WILL THESE CHANGES IN REVENUE REQUIREMENTS BE REFLECTED ON NORTH DAKOTA CUSTOMERS' BILLS?

A. Table 7, below, shows the forecasted incremental impact on average monthly bills in North Dakota from 2020 to 2024.

Table 7: ND Forecasted Incremental Impact on Average Monthly Bills

	Residential	Commercial Non Demand	C&I Demand Billed *
2020	$0.18	$0.24	$5.91
2021	$0.10	$0.11	$2.93
2022	$0.07	$0.05	$1.53
2023	$0.06	$0.03	$1.03
2024	-$0.02	-$0.10	-$2.18
* Customer kWh usage and rate impacts for C&I demand billed customers varies significantly			

IV. CONCLUSION

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

A. Yes, it does.

I. Strategist Modeling Assumptions

1. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.53 percent. The rates shown in Table 1 were calculated by taking a weighted average of NSP jurisdictions from the April 2018 Corporate Assumptions Memo.

Table 1: Capital Structure

	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	45.60%	4.87%	2.22%	1.32%
Common Equity	52.50%	9.39%	4.93%	4.93%
Short-Term Debt	1.90%	2.85%	0.05%	0.05%
Total			**7.20%**	**6.30%**

2. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling and are developed using long-term forecasts from Global Insight. The General inflation rate is from the "Chained Price Index for Total Personal Consumption Expenditures" published in the second quarter of 2018.

- General inflation – The inflation rate used for construction (capital) costs and any other escalation factor related to general inflationary trends is 2.0%.

3. Reserve Margin

The reserve margin at the time of MISO's peak is 8.4 percent. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 8.4\%) - 1 = 2.98\%.$$

Table 2: Reserve Margin

Reserve Margin	
Coincidence Factor	5.00%
MISO Coincident Peak Reserve Margin %	8.40%
Effective RM Based on Non-coincident Peak	2.98%

4. Demand and Energy Forecast

The Fall 2018 Load Forecast developed by the Xcel Energy Load Forecasting group is used. The forecast is shown with no DG solar reduction, as solar was modeled as a resource.

Table 3: Fall 2018 Demand and Energy Forecast

Demand (MW)					Energy (GWh)				
Year	Model Output	W/ Hist DSM, Building Code Adj	w DSM/Eff Adjustments	Final w EV Adjustments	Year	Model Output	W/ Hist DSM, Building Code Adj	w DSM/Eff Adjustments	Final w EV Adjustments
2018	10,415	9,241	9,151	9,152	2018	50,447	44,348	43,909	43,914
2019	10,424	9,313	9,131	9,136	2019	50,530	44,649	43,772	43,798
2020	10,499	9,399	9,146	9,156	2020	50,847	45,129	43,800	43,865
2021	10,559	9,497	9,173	9,191	2021	50,746	45,223	43,449	43,560
2022	10,621	9,623	9,226	9,251	2022	50,844	45,598	43,375	43,529
2023	10,684	9,719	9,251	9,285	2023	50,991	45,857	43,186	43,394
2024	10,755	9,831	9,291	9,329	2024	51,326	46,318	43,189	43,425
2025	10,842	9,949	9,338	9,376	2025	51,333	46,589	43,021	43,257
2026	10,939	10,101	9,418	9,456	2026	51,483	47,061	43,044	43,281
2027	11,038	10,287	9,533	9,571	2027	51,699	47,722	43,256	43,493
2028	11,140	10,494	9,669	9,706	2028	52,079	48,780	43,852	44,089
2029	11,232	10,634	9,737	9,775	2029	52,105	49,097	43,735	43,972
2030	11,320	10,795	9,827	9,864	2030	52,279	49,704	43,893	44,130
2031	11,418	10,940	9,899	9,937	2031	52,516	50,195	43,935	44,172
2032	11,518	11,065	10,044	10,082	2032	52,895	50,712	44,424	44,661
2033	11,619	11,204	10,201	10,239	2033	52,931	50,918	44,639	44,875
2034	11,717	11,333	10,331	10,369	2034	53,112	51,274	44,995	45,232
2035	11,813	11,443	10,441	10,478	2035	53,346	51,577	45,298	45,534
2036	11,912	11,568	10,566	10,604	2036	53,746	52,103	45,806	46,042
2037	12,006	11,675	10,672	10,710	2037	53,750	52,169	45,890	46,126
2038	12,100	11,769	10,766	10,804	2038	53,911	52,329	46,050	46,287
2039	12,197	11,867	10,864	10,902	2039	54,165	52,584	46,305	46,541
2040	12,301	11,970	10,968	11,005	2040	54,589	53,007	46,709	46,946
2041	12,396	12,065	11,063	11,101	2041	54,599	53,018	46,739	46,975
2042	12,488	12,157	11,155	11,192	2042	54,767	53,186	46,907	47,143
2043	12,581	12,250	11,248	11,285	2043	55,031	53,450	47,171	47,407
2044	12,693	12,362	11,360	11,398	2044	55,467	53,884	47,587	47,823
2045	12,765	12,434	11,432	11,469	2045	55,503	53,921	47,642	47,879
2046	12,851	12,520	11,518	11,556	2046	55,700	54,119	47,840	48,076
2047	12,947	12,616	11,614	11,652	2047	55,996	54,415	48,136	48,372
2048	13,035	12,705	11,703	11,741	2048	56,359	55,038	48,740	48,977
2049	13,124	12,794	11,792	11,830	2049	56,435	54,854	48,575	48,811
2050	13,213	12,883	11,881	11,919	2050	56,667	55,085	48,806	49,042
2051	13,302	12,972	11,970	12,008	2051	56,899	55,316	49,037	49,274
2052	13,391	13,062	12,059	12,097	2052	57,288	55,700	49,403	49,640
2053	13,480	13,151	12,148	12,186	2053	57,362	55,779	49,500	49,736
2054	13,595	13,265	12,263	12,301	2054	57,812	56,228	49,949	50,185
2055	13,684	13,355	12,352	12,390	2055	58,043	56,459	50,180	50,417
2056	13,773	13,444	12,441	12,479	2056	58,436	56,847	50,549	50,786
2057	13,862	13,533	12,531	12,568	2057	58,507	56,922	50,643	50,880

5. DSM Forecast

The DSM forecast corresponds to what was used in the 2018v2.0 Load Forecast and assumes impacts expected at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period and is what is embedded in the 2018v2 Load Forecast.

Table 4: DSM Forecast

Year	Energy (MWh)	Demand (MW)
2018	439	114
2019	877	229
2020	1,330	316
2021	1,774	402
2022	2,223	489
2023	2,671	576
2024	3,129	663
2025	3,568	750
2026	4,017	837
2027	4,465	924
2028	4,928	1,011
2029	5,362	1,097
2030	5,811	1,184
2031	6,259	1,271
2032	6,287	1,244
2033	6,279	1,216
2034	6,279	1,216
2035	6,279	1,216
2036	6,297	1,216
2037	6,279	1,216
2038	6,279	1,216
2039	6,279	1,216
2040	6,297	1,216
2041	6,279	1,216
2042	6,279	1,216
2043	6,279	1,216
2044	6,297	1,216
2045	6,279	1,216
2046	6,279	1,216
2047	6,279	1,216
2048	6,297	1,216
2049	6,279	1,216
2050	6,279	1,216
2051	6,279	1,216
2052	6,297	1,216
2053	6,279	1,216
2054	6,279	1,216
2055	6,279	1,216
2056	6,297	1,216
2057	6,279	1,216

6. Demand Response Forecast

The Load Management Forecast used was developed by the Xcel Energy Load Research group, 2018v4 vintage plus 406 MW of incremental generic DR starting in 2023. The table below shows the July demand.

Table 5: 2018 Load Management Forecast

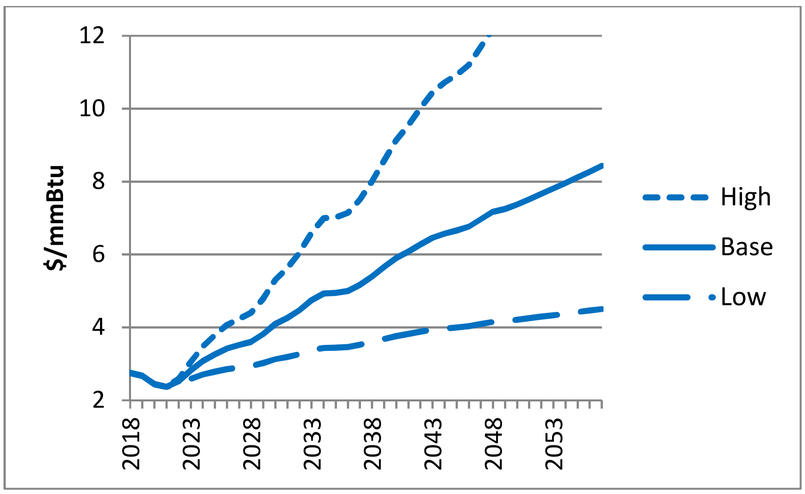
DR Forecast	
Year	July Demand (MW)
2018	899
2019	916
2020	932
2021	948
2022	962
2023	1,409
2024	1,413
2025	1,418
2026	1,423
2027	1,418
2028	1,408
2029	1,398
2030	1,388
2031	1,378
2032	1,369
2033	1,360
2034	1,351
2035	1,343
2036	1,335
2037	1,327
2038	1,319
2039	1,312
2040	1,304
2041	1,297
2042	1,291
2043	1,284
2044	1,277
2045	1,271
2046	1,265
2047	1,259
2048	1,252
2049	1,246
2050	1,240
2051	1,233
2052	1,227
2053	1,221
2054	1,214
2055	1,208
2056	1,202
2057	1,196

7. Natural Gas Price Forecasts

Henry Hub natural gas prices are developed using a blend of market information (New York Mercantile Exchange futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA), and Petroleum Industry Research Associates (PIRA).

Gas Prices as of October 18, 2018 were used. High and low gas price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base natural gas cost forecast starting in year 2022.

Figure 1: Ventura Natural Gas Price Forecast and Sensitivities



8. Natural Gas Transportation Costs

Gas transportation variable costs include the gas transportation charges and the Fuel Lost & Unaccounted (FL&U) for all of the pipelines the gas flows through from the Ventura Hub to the generators facility. The FL&U charge is stated as a percentage of the gas expected to be consumed by the plant, effectively increasing the gas used to operate the plant, and is at the price of gas commodity being delivered to the plant. Table 10 contains gas transportation charges for generic thermal resources.

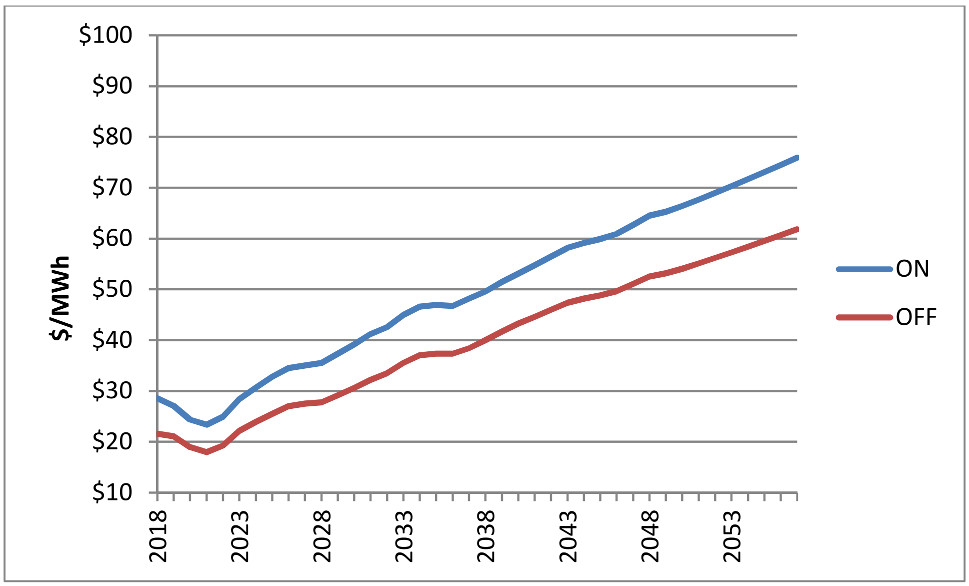
9. Natural Gas Demand Charges

Gas demand charges are fixed annual payments applied to resources to guarantee that natural gas will be available (normally called "firm gas"). Typically, firm gas is obtained to meet the needs of the winter peak as enough gas is normally available during the summer. Table 10 contains gas demand charges for generic thermal resources.

10. Electric Power Market Prices

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market power prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA, and PIRA. Figure 2 below shows the market prices under zero cost CO_2 assumptions.

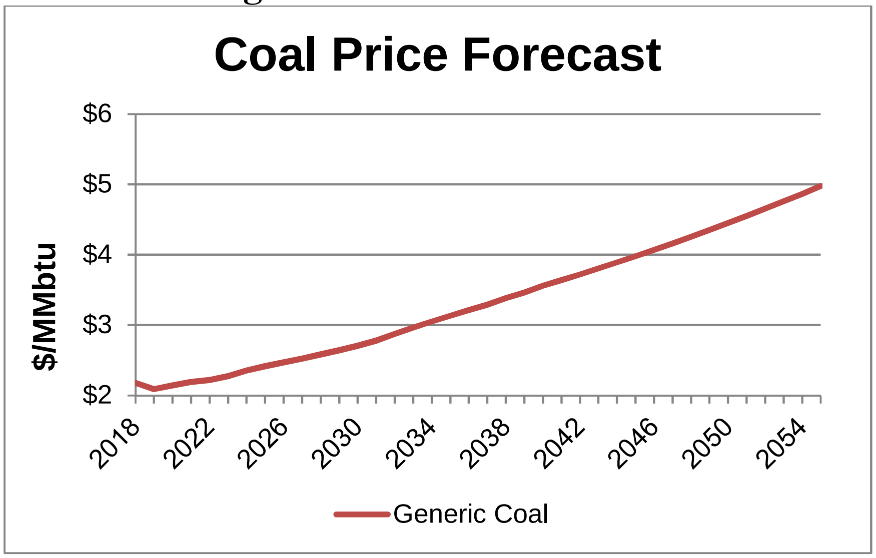
Figure 2: Minn Hub Average On and Off Peak Market Price



11. Coal Price Forecast

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices. Typically coal volumes and prices are under contract on a plant-by-plant basis for a one- to five-year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Layered on top of the coal prices are transportation charges, SO_2 costs, freeze control, and dust suppressant, as required.

Figure 3: Coal Price Forecast



12. Transmission Delivery Costs

Generic 2x1 combined cycle (CC), generic combustion turbine (CT), generic wind, and generic solar have assumed transmission delivery costs. The table below shows the transmission delivery costs on a $/kW basis. The CC and CT costs were developed based on the average of several potential sites in the Minnesota. The general site locations were investigated by Transmission Access for impacts to the transmission grid and expected resulting upgrade costs

Table 6: Transmission Delivery Costs

	$/kw
CC	$ 330
CT	$ 100
Wind	$ 200
Solar	$ 70

13. Interconnection Costs

Estimates of interconnection costs of the generic resources were included in the capital cost estimates.

14. Effective Load Carrying Capability (ELCC) Capacity Credit for Wind Resources

Existing wind units is based on current MISO accreditation. New wind additions are given a capacity credit equal to 15.6 percent of their nameplate rating per MISO 2017/2018 Wind Capacity Report.

15. ELCC Capacity Credit for Utility Scale Solar Photovoltaic (PV) Resources

Utility scale generic solar PV additions used in modeling the alternative plans were given a capacity credit equal to 50 percent of the AC nameplate capacity.

16. Spinning Reserve Requirement

Spinning Reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 182 MW and is based on a 12 month rolling average of spinning reserves carried by the NSP System within MISO.

17. Emergency Energy Costs

Emergency Energy Costs were assigned in the Strategist model if there were not enough resources available to meet energy requirements. The cost was set at $500/MWh.

18. Wind Integration Costs

Wind integration costs were priced based upon the results of the NSP System Wind Integration Cost Study. Wind integration costs contain five components:

1. MISO Contingency Reserves
2. MISO Regulating Reserves
3. MISO Revenue Sufficiency Guarantee Charges
4. Coal Cycling Costs
5. Gas Storage Costs

Table 7: Wind Integration Costs

Year	Integration $/MWh		Coal Cycling $/MWh	
	Wind	Solar	Wind	Solar
2018	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00
2020	0.41	0.41	0.00	0.00
2021	0.42	0.42	0.00	0.00
2022	0.43	0.43	0.00	0.00
2023	0.44	0.44	0.00	0.00
2024	0.44	0.44	0.00	0.00
2025	0.45	0.45	0.00	0.00
2026	0.46	0.46	0.00	0.00
2027	0.47	0.47	0.00	0.00
2028	0.48	0.48	0.00	0.00
2029	0.49	0.49	0.00	0.00
2030	0.50	0.50	0.00	0.00
2031	0.51	0.51	0.00	0.00
2032	0.52	0.52	0.00	0.00
2033	0.53	0.53	0.00	0.00
2034	0.54	0.54	0.00	0.00
2035	0.55	0.55	0.00	0.00
2036	0.56	0.56	0.00	0.00
2037	0.57	0.57	0.00	0.00
2038	0.59	0.59	0.00	0.00
2039	0.60	0.60	0.00	0.00
2040	0.61	0.61	0.00	0.00
2041	0.62	0.62	0.00	0.00
2042	0.63	0.63	0.00	0.00
2043	0.65	0.65	0.00	0.00
2044	0.66	0.66	0.00	0.00
2045	0.67	0.67	0.00	0.00
2046	0.69	0.69	0.00	0.00
2047	0.70	0.70	0.00	0.00
2048	0.71	0.71	0.00	0.00
2049	0.73	0.73	0.00	0.00
2050	0.74	0.74	0.00	0.00
2051	0.76	0.76	0.00	0.00
2052	0.77	0.77	0.00	0.00
2053	0.79	0.79	0.00	0.00
2054	0.80	0.80	0.00	0.00
2055	0.82	0.82	0.00	0.00
2056	0.84	0.84	0.00	0.00
2057	0.85	0.85	0.00	0.00

19. Wind Congestion Costs

Wind Congestion Costs were developed internally by Resource Planning using the MISO MTEP 2018 models and looking at the average congestion costs between representative wind bus locations and NSP.NSP. From the study, we included a congestion cost of $3.43 per MWh in 2020, escalating at 2% thereafter for all new wind projects.

Table 8: Wind Congestion Costs

	Wind Congestion $/MWh	
	Existing Resources	New Resources
2018	-	-
2019	-	-
2020	-	3.43
2021	-	3.50
2022	-	3.57
2023	-	3.64
2024	-	3.71
2025	-	3.79
2026	-	3.86
2027	-	3.94
2028	-	4.02
2029	-	4.10
2030	-	4.18
2031	-	4.27
2032	-	4.35
2033	-	4.44
2034	-	4.53
2035	-	4.62
2036	-	4.71
2037	-	4.80
2038	-	4.90
2039	-	5.00
2040	-	5.10
2041	-	5.20
2042	-	5.30
2043	-	5.41
2044	-	5.52
2045	-	5.63
2046	-	5.74
2047	-	5.86
2048	-	5.97
2049	-	6.09
2050	-	6.22
2051	-	6.34
2052	-	6.47
2053	-	6.60
2054		6.73
2055		6.86
2056		7.00
2057		7.14

20. Distributed Generation and Community Solar Gardens

The small solar inputs are based on the most recent Company forecast.

21. Assumption and Sensitivity Descriptions

The modeling uses the following assumptions and sensitivities. The Base Assumptions are combined with the Sensitivities to test the modeling results for critical variables.

Table 9: Assumption and Sensitivity Descriptions

Base Assumptions	Assumption Description
PVRR Base	This assumption optimizes under the PVRR Base Assumption, which does not include Regulated CO_2 Costs, Externality Costs, and the Surplus Capacity Credit. All Strategist outputs, except the Markets Off sensitivity, assume the modeling of MISO Energy Market interactions. The following sensitivities were ran using the PVRR assumption as the starting point: Low Gas, High Gas, Low Load, High Load, Markets off no dump, Markets off with dump, 3% Esc costs, 1% esc. costs.

Sensitivities	Sensitivity Description
Low Gas Price	This sensitivity decreases the annual year-over-year percent change in natural gas prices by 50% starting in year 2022.
High Gas Price	This sensitivity increases the annual year-over-year percent change in natural gas prices by 50% starting in year 2022.
Low Load	This sensitivity uses a minus one standard deviation from the base demand and energy forecast.
High Load	This sensitivity uses a plus one standard deviation from the base demand and energy forecast.
Markets Off No Dump Credit	This sensitivity removes the modeling of the Company's hourly sales in the MISO Energy Market. No credit was applied for dump energy.
Markets Off With Dump Credit	This sensitivity removes the modeling of the Company's hourly purchases in the MISO Energy Market and allows for a credit of one half of the all hours market price for dump energy.
3% esc ongoing costs	MEC ongoing costs to escalate by 3% annually, vs. the 20% base inflation assumption.
1% Esc ongoing costs	MEC ongoing costs to escalate by 1% annually, vs. the 20% base inflation assumption.

22. Owned Unit Modeled Operating Characteristics and Costs

Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each company owned resource.

a. Retirement Date
b. Maximum Capacity
c. Current Unforced Capacity (UCAP) Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and particulate matter (PM)
l. Contribution to spinning reserve

m. Fuel prices
n. Fuel delivery charges

23. Thermal Power Purchase Agreement (PPA) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

24. Renewable Energy PPAs and Owned Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each renewable energy PPA and owned unit.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind hourly patterns were developed through a "Typical Wind Year" process where individual months were selected from the years 2014-2017 to develop a typical year. Actual generation data from the selected months were used to develop the profiles for each wind farm. For farms where generation data was not complete or not available, data from nearby similar farms were used.

Solar hourly patterns were taken from the ELCC Study from Fall 2013 and updated to reflect the ELCC as stated above. The fixed panel pattern is an average of the four orientations and three years (2008-2010) of data and single-axis tracking pattern is an average of three years of data.

25. Generic Assumptions

Generic resources were modeled based upon their expected operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each generic resource.

Thermal

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Renewable

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Tables 10-11 below show the assumptions for the generic thermal and renewable resources.

Table 10: Thermal Generic Information (Costs in 2018 Dollars)

Resource	Sherco CC	Generic CC	Generic CT	Generic CT	Generic CT
Technology	7H	7H	7H	7F	7H
Location Type	Brownfield	Greenfield	Brownfield	Brownfield	Greenfield
Cooling Type	Wet	Dry	Dry	Dry	Dry
Book life	40	40	40	40	40
Nameplate Capacity (MW)	916	916	374	232	374
Summer Peak Capacity with Ducts (MW)	870	870	NA	NA	NA
Summer Peak Capacity without Ducts (MW)	643	643	331	228	331
Capital Cost ($/kW)	$914	$951	$446	$495	$445
Electric Transmission Delivery ($/kW)	NA	$301	NA	NA	$100
Ongoing Capital Expenditures ($/kW-yr)	$6.77	$6.77	$4.77	$3.85	$3.85
Gas Demand ($/kW-yr) 2018$	$32.56	$21.14	NA	NA	$2.07
Fixed O&M Cost ($000/yr) 2018$	$2,605	$3,105	$422	$736	$668
Variable O&M Cost ($/MWh)	$1.42	$1.42	$4.90	$4.90	$4.90
Levelized $/kw-mo (All Fixed Costs) $2018	$12.04	$12.71	$4.62	$5.13	$5.58
Heat Rate with Duct Firing (btu/kWh)	6,494	6,818	NA	NA	NA
Heat Rate 100% Loading (btu/kWh)	6,331	6,647	9,042	9,791	9,042
Heat Rate 75% Loading (btu/kWh)	6,464	6,787	9,474	10,234	9,474
Heat Rate 50% Loading (btu/kWh)	6,876	7,220	10,833	12,006	10,833
Heat Rate 25% Loading (btu/kWh)	7,831	8,222	11,279	12,835	11,279
Forced Outage Rate	3%	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	2	2	2

Table 11: Renewable Generic ECC Costs - $/MWh

GENERIC WIND			GENERIC SOLAR		
Year	PTC	ECC ($/MWH)	Year	ITC	ECC ($/MWH)
2023	60%	33.06	2023	30%	43.45
2024	40%	37.72	2024	30%	43.75
2025	0%	46.48	2025	10%	44.05
2026	0%	46.76	2026	10%	44.34
2027	0%	47.07	2027	10%	44.64
2028	0%	47.39	2028	10%	44.93
2029	0%	47.74	2029	10%	45.22
2030	0%	48.11	2030	10%	45.50
2031	0%	48.55	2031	10%	46.04
2032	0%	49.00	2032	10%	46.58
2033	0%	49.49	2033	10%	47.12
2034	0%	50.00	2034	10%	47.66
2035	0%	50.53	2035	10%	48.21
2036	0%	51.09	2036	10%	48.77
2037	0%	51.68	2037	10%	49.32
2038	0%	52.30	2038	10%	49.88
2039	0%	52.95	2039	10%	50.44
2040	0%	53.63	2040	10%	51.01
2041	0%	54.34	2041	10%	51.52
2042	0%	55.08	2042	10%	52.02
2043	0%	55.86	2043	10%	52.53
2044	0%	56.67	2044	10%	53.04
2045	0%	57.53	2045	10%	53.55
2046	0%	58.41	2046	10%	54.06
2047	0%	59.34	2047	10%	54.57
2048	0%	60.32	2048	10%	55.08
2049	0%	61.33	2049	10%	55.58
2050	0%	62.39	2050	10%	56.09
2051	0%	63.64	2051	10%	57.21
2052	0%	64.91	2052	10%	58.36
2053	0%	66.21	2053	10%	59.52
2054	0%	67.53	2054	10%	60.71
2055	0%	68.88	2055	10%	61.93
2056	0%	70.26	2056	10%	63.17
2057	0%	71.66	2057	10%	64.43

II. Strategist Modeling Outputs

1. Annual Net Costs and Savings

The PVRR Base annual costs and savings for the proposed Mankato project are in Figure 4 and Table 12.

Figure 4: Annual PVRR Net Costs (Savings) in $millions

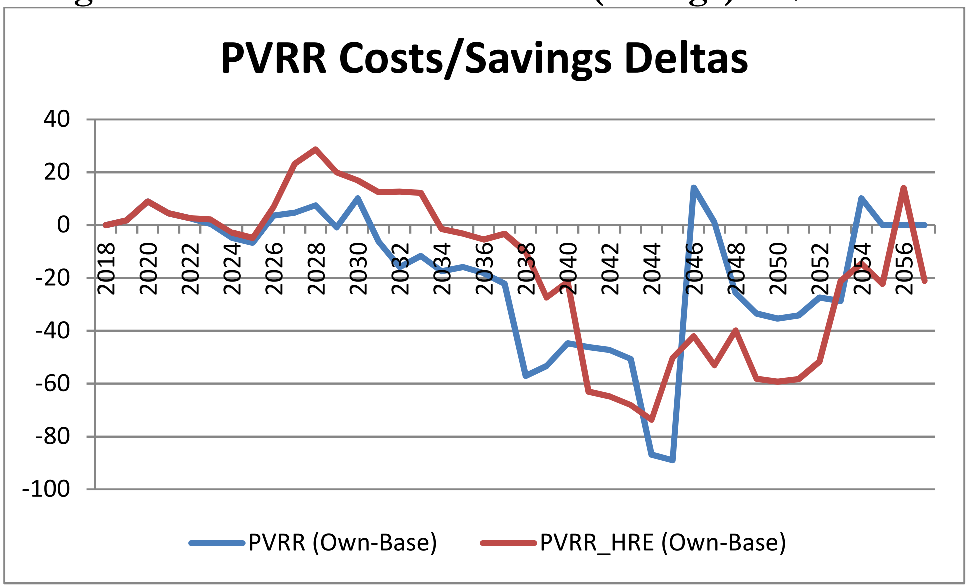


Table 32: Annual PVRR Net Costs (Savings) in $millions

2018 PVRR

	NGB	HRE	Delta
Capital Cost of Mankato Purchase	915	915	0
Fixed Savings of Mankota PPA	(555)	(555)	0
Fixed Cost/Expansion Plan Cost/(Savings)	(359)	(365)	(6)
VOM Cost/(Savings)	(47)	(28)	19
Fuel Cost/(Savings)	21	13	(8)
Market Cost/(Savings)	(71)	(6)	65
PPA Starts/Own Start Fuel Cost/(Savings)	(46)	(39)	7
Total Cost/(Savings)	(142)	(66)	77

2. Expansion Plans

The Reference Case is represented in Table 13 and Table 14 in which the generation from Mankato is included as a PPA. The expansion plans with the proposed ownership of the 762MW Mankato Energy Center addition are shown in Tables 15 and 16.

Table 13: Reference Case Expansion Plan

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Firm Capacity														
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	322	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	728	0	0	0	0
Greenfield CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greenfield CT	0	0	0	0	0	0	0	0	0	0	0	0	642	0
Brownfield H CT	0	0	0	0	0	0	0	0	0	642	0	0	0	0
Brownfield F CT	0	0	0	0	0	0	0	0	0	0	0	0	0	200
Nameplate Capacity														
Wind	0	1,155	400	300	0	126	0	20	21	67	35	80	8	206
Solar	0	0	0	0	0	412	304	197	147	0	402	0	0	0

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Firm Capacity														
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greenfield CC	0	844	0	844	0	0	844	0	0	0	0	0	0	0
Greenfield CT	321	0	321	0	0	0	0	321	0	642	321	0	321	0
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield F CT	0	0	200	0	0	0	0	0	0	0	0	0	0	0
Nameplate Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	87	379	113	29	334	7	0	6	142	181	183	0	79	38
Solar	0	0	0	0	29	0	0	0	0	0	323	236	126	25

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	Total
Firm Capacity													
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	322
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	0	728
Greenfield CC	0	0	0	844	0	0	0	0	0	0	0	0	3,376
Greenfield CT	0	0	642	0	0	0	0	321	0	0	321	0	4,173
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	642
Brownfield F CT	0	0	0	0	0	0	0	0	0	0	0	0	400
Nameplate Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	-44	-48	0	0	0	0	0	0	0	0	0	0	3,903
Solar	0	0	0	0	0	0	0	0	0	0	0	0	2,201

Table 14: Reference Case Expansion Plan with High Renewables

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Firm Capacity														
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	322	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	728	0	0	0	0
Greenfield CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greenfield CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield F CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nameplate Capacity														
Wind	0	1,155	400	300	0	876	0	20	21	67	35	80	8	206
Solar	0	0	0	0	0	412	1,304	197	1,147	1,000	1,402	0	1,000	0

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Firm Capacity														
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greenfield CC	0	0	0	0	0	0	0	0	0	844	0	0	0	0
Greenfield CT	0	0	0	321	0	321	321	321	0	0	0	0	0	0
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield F CT	0	0	200	0	0	0	0	0	0	0	0	0	0	0
Nameplate Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	87	379	113	29	334	7	0	6	892	181	183	0	79	38
Solar	0	500	0	1,000	29	0	500	0	0	0	323	736	126	25

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	Total
Firm Capacity													
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	322
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	0	728
Greenfield CC	0	0	0	844	0	0	0	0	0	0	0	0	1,688
Greenfield CT	321	0	321	0	0	0	0	0	321	0	0	321	2,568
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield F CT	0	0	0	0	0	0	0	0	0	0	0	0	200
Nameplate Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	-44	-48	0	0	0	0	0	0	0	0	0	0	5,403
Solar	0	0	500	0	0	0	0	0	0	0	0	0	10,201

Table 15: Owned Mankato Expansion Plan

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Firm Capacity														
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	627	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	728	0	0	0	0
Greenfield CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greenfield CT	0	0	0	0	0	0	0	0	0	0	0	0	642	0
Brownfield H CT	0	0	0	0	0	0	0	0	0	321	0	0	321	0
Brownfield F CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nameplate Capacity														
Wind	0	1,155	400	300	0	126	0	20	21	67	35	80	8	206
Solar	0	0	0	0	0	412	304	197	147	0	402	0	0	0

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Firm Capacity														
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greenfield CC	0	844	0	844	0	0	0	0	0	0	0	0	0	0
Greenfield CT	0	0	321	0	0	0	642	321	0	642	321	0	0	0
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield F CT	200	0	200	0	0	0	0	0	0	0	0	0	0	0
Nameplate Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	87	379	113	29	334	7	0	6	142	181	183	0	79	38
Solar	0	0	0	0	29	0	0	0	0	0	323	236	126	25

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	Total
Firm Capacity													
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	627
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	0	728
Greenfield CC	844	0	0	844	0	0	0	0	0	0	0	0	3,376
Greenfield CT	0	0	321	0	0	0	0	321	321	0	321	0	4,173
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	642
Brownfield F CT	0	0	0	0	0	0	0	0	0	0	0	0	400
Nameplate Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	-44	-48	0	0	0	0	0	0	0	0	0	0	3,903
Solar	0	0	0	0	0	0	0	0	0	0	0	0	2,201

Table 16: Owned Mankato Expansion Plan with High Renewables

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Firm Capacity														
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	627	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	728	0	0	0	0
Greenfield CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greenfield CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield F CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nameplate Capacity														
Wind	0	1,155	400	300	0	876	0	20	21	67	35	80	8	206
Solar	0	0	0	0	0	412	1,304	197	1,147	1,000	1,402	0	1,000	0

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Firm Capacity														
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greenfield CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Greenfield CT	0	0	0	321	0	321	321	0	0	642	0	0	0	321
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield F CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nameplate Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	87	379	113	29	334	7	0	6	892	181	183	0	79	38
Solar	0	500	0	1,000	29	0	500	0	0	0	323	736	126	25

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	Total
Firm Capacity													
MEC I	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC II	0	0	0	0	0	0	0	0	0	0	0	0	0
Mankato Owned	0	0	0	0	0	0	0	0	0	0	0	0	627
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	0	728
Greenfield CC	0	0	0	844	0	0	0	0	0	0	0	0	844
Greenfield CT	321	0	321	0	0	0	0	321	321	0	321	0	3,531
Brownfield H CT	0	0	0	0	0	0	0	0	0	0	0	0	0
Brownfield F CT	0	0	0	0	0	0	0	0	0	0	0	0	0
Nameplate Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	-44	-48	0	0	0	0	0	0	0	0	0	0	5,403
Solar	0	0	500	0	0	0	0	0	0	0	0	0	10,201

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

NORTHERN STATES POWER COMPANY
ADVANCE PRUDENCE – ACQUISITION OF
THE 375 MW MANKATO ENERGY
CENTER AND THE 345 MW MANKATO
ENERGY CENTER II

CASE NO. PU-18-___

VERIFICATION

STATE OF MINNESOTA)
)ss.
COUNTY OF HENNEPIN

Philip Joseph Martin, being first duly sworn on oath, deposes and says that he is the Director of Resource Planning and Bidding for Xcel Energy Services Inc. on behalf of Applicant Northern States Power Company, a Minnesota corporation, in the above-captioned matter, that the testimony and schedule submitted in the above-captioned matter under his name 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.

Philip Joseph Martin

Subscribed and sworn to before me on this 3 day of December, 2018.

ADRIANA M. SCHNEIDER
NOTARY PUBLIC - MINNESOTA
My Commission Expires
January 31, 2021

Notary Public
My Commission Expires: 1-31-21