Xcel Energy

2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
(701) 241-8632
dave.sederquist@xcelenergy.com

March 16, 2015

—Via Electronic Mail—

Darrell Nitschke
Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Department 408
600 East Boulevard
Bismarck, North Dakota 58505-0480

RE: 2015 UPPER MIDWEST INTEGRATED RESOURCE PLAN - SUPPLEMENT
CASE NO. PU-15-19

Dear Mr. Nitschke:

Northern States Power Company submits eight (8) copies of the enclosed Supplement to its 2015 Upper Midwest Integrated Resource Plan (IRP) covering the period of 2016 to 2030. The IRP was provided to the North Dakota Public Service Commission on January 5, 2015.

This Supplement to the IRP is being provided in each of the five jurisdictions served by Xcel Energy's NSP operating companies. We look forward to continued discussions with the Commission and its staff regarding this IRP.

Please contact me at (701) 241-8632 or via email at dave.sederquist@xcelenergy.com if you have any questions about this submittal. Alternatively, you may wish to contact Paul Johnson from our Resource Planning group at (612) 330-6238 or via email at Paul.B.Johnson@xcelenergy.com.

Sincerely,

David H. Sederquist

DAVID H. SEDERQUIST
SR. REGULATORY/FINANCIAL CONSULTANT
NORTHERN STATES POWER COMPANY

Enclosure

Xcel Energy®

SUPPLEMENT TO XCEL ENERGY'S 2016-2030 UPPER MIDWEST RESOURCE PLAN SUBMITTED JANUARY 2, 2015

DOCKET NO. E002/RP-15-21

March 16, 2015

2016-2030 Upper Midwest Resource Plan – Supplement
Table of Contents

2016-2030 Upper Midwest Resource Plan – Supplement
Tables and Figures

Supplement

Appendix – Strategist Modeling and Outputs Updates

I. INTRODUCTION

Northern States Power Company (NSP), a Minnesota corporation, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Supplement to its 2016-2030 Upper Midwest Resource Plan, submitted January 2, 2015, as required by the Commission's January 16, 2015 NOTICE OF COMMENT PERIOD AND PROCEDURES ON RESOURCE PLAN in Docket No. E002/RP-15-21.

This Supplement incorporates recent Commission outcomes that increase the amount of capacity on our system, and includes updated assumptions for a greater adoption of *small*-scale solar resources in the early years of the planning period, which was prompted by the very robust response to our December 2014 launch of our Community Solar Gardens program. The specific resource changes and additions we have incorporated into our modeling are as follows:

- Competitive Acquisition Process (CAP) proceeding (Docket No. E002/CN-12-1240):[1]
  - *100 MW Geronimo Energy Aurora solar project.*[2] Accelerates the utility-scale solar resources on the NSP System; expected in-service 2016,
  - *345 MW Calpine Corporation Mankato Energy Center II (MEC II) natural gas combined cycle project.*[3] Increases the natural gas resources on the NSP System; expected in-service no later than 2019, and
  - *232 MW Xcel Energy Black Dog 6 natural gas combustion turbine project.*[4] Increases the natural gas resources on the NSP System; expected to achieve commercial operation no later than 2019.[5]
- Community Solar Gardens (CSG) proceeding (Docket No. E002/M-13-867):
  - Accelerates the addition of 200 MW of small-scale solar additions to the Company's Solar*Rewards Community program in the pre-2020 timeframe.

Since our January 2 filing (Initial Filing) assumed the inclusion of approximately 187

---

[1] *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need*, MPUC Docket No. E002/CN-12-1240, ORDER APPROVING POWER PURCHASE AGREEMENT WITH CALPINE, APPROVING POWER PURCHASE AGREEMENT WITH GERONIMO, AND APPROVING PRICE TERMS WITH XCEL (February 5, 2015). This Order is subject to several requests for reconsideration and/or clarification; we may have to supplement this filing depending on that outcome.

[2] Nameplate/Installed Capacity 100 MW; Contracted Capacity 72 MW.

[3] Nameplate Capacity 345 MW; Installed Summer Capacity 290 MW; Accredited Capacity 278 MW.

[4] Nameplate/Installed Capacity 232 MW; Accredited Capacity 208 MW.

[5] The Company is on schedule for a 2018 in-service date for the Calpine and Black Dog capacity additions; however, we took a conservative approach in our modeling and included the first full year of operation of both of these assets beginning in March to June of 2019.

MW from our solar request for proposals (RFP) last year, we did not have to make any changes to this Supplement to incorporate the Commission's decision in our Solar RFP proceeding (Docket No. E002/M-14-162).

In addition to modeling those resource additions, the Company evaluated the policy guidance provided in the CAP proceeding decision. As we stated in that proceeding, a conservative approach is warranted in resource planning to ensure adequate capacity on our system under all reasonably plausible outcomes.[6] The Commission's Order appeared to concur with that approach. We therefore took a conservative approach in our modeling for this Supplement, given the uncertainty in that time period, to help ensure that the capacity provided by those resources added as a result of the CAP proceeding would be available to meet any potential system needs. We assumed that capacity would be maintained from the in-service date of the CAP projects through 2024, the next time period when the system requires additional capacity.

An alternative resource planning approach could have us use that surplus capacity to potentially fulfill a policy directive such as retiring a Sherco unit; however, for the purpose of demonstrating the value of maintaining this system flexibility, we took a conservative approach in our baseline assumptions for this Supplement. In an effort to provide a transparent record for this proceeding and for those who may not agree with this approach, we have also included an analysis that allows that capacity to be available for use in studying other alternatives in the period extending from the in-service date through 2024. Economic analyses of both of these approaches are included in Section VI of this Supplement.

After incorporating these changes, our updated Preferred Plan continues to provide the greatest benefits to our customers and stakeholders. It continues to provide a proactive and affirmative approach for significantly reducing CO_2 emissions, while moderating costs and retaining flexibility to respond to future environmental requirements and market trends.

In our Initial Filing, we asked the Commission to allow for a more non-traditional procedural schedule so that we could engage in collaborative discussions with our stakeholders. On February 10, 2015, we held our first in a series of stakeholder meetings where we discussed our Preferred Plan and its assumptions and impacts. The meeting was well-attended, with participants engaged and asking many questions. As we discuss in this Supplement, we will hold technical workshops to discuss key areas of interest that emerged – namely, our modeling assumptions, projected demand side management and demand response achievements, customer impacts, the impact

[6] MPUC Docket No. E002/CN-12-1240, XCEL ENERGY'S EXCEPTIONS TO ALJ REPORT, (January 21, 2014).

of evolving environmental requirements on our baseload generating facilities, and the growing interest in distributed generation.

As part of formal and informal stakeholder discussions, we were asked for additional information about our Initial Filing. In this Supplement we provide information that responds to several of these requests. Specifically, we have included: (1) an appendix that provides an expanded explanation of our modeling assumptions and an explanation of those that have been updated; (2) identification of the work we are doing to develop a more detailed approximation of rate impacts of our Preferred Plan by customer class; and (3) additional modeling and discussion regarding the costs and other implications of potential retirement of our Sherburne County (Sherco) Unit 1 and/or 2 generating facilities in the early 2020s.

With respect to Sherco Units 1 and 2, our updated modeling continues to demonstrate that operation of these units through the planning period will provide our customers the benefit of their investment in these baseload units, while accomplishing substantial emission reduction and maintaining a diverse fuel portfolio. However, we also discuss our study and the analysis we have requested that the Midcontinent Independent System Operator, Inc. (MISO) perform to more fully understand the technical implications and considerations associated with the potential retirement of one of these important baseload facilities.

In conclusion, our Preferred Plan continues to provide an innovative, flexible and cost-effective approach for addressing the evolving resource planning landscape. We continue to believe our Preferred Plan is in the public interest, and look forward to further engagement with our stakeholders throughout this process.

II. BACKGROUND

The Company submitted its 2016-2030 Upper Midwest Resource Plan on January 2, 2015, as required by the Commission's May 23, 2014 Order in the CAP proceeding, which was an outcome from our last Resource Plan. The Commission Order in our last Resource Plan identified a resource need of 150 MW starting in 2017, growing to 500 MW by 2019, for which the Company initiated a competitive acquisition process.[7] The Commission made determinations in that proceeding in December 2014; due to their timing, we were unable to incorporate these determinations into our Initial Filing.

[7] *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, MPUC Docket No. E002/RP-10-825 ORDER APPROVING PLAN, FINDING NEED, ESTABLISHING FILING REQUIREMENTS, AND CLOSING DOCKET, (March 5, 2013).

In addition, at the time of our Initial Filing, the Commission's decisions regarding our Solar RFP portfolio were pending in Docket No. E002/M-14-162. In that proceeding, we had proposed to add up to 187 MW of utility-scale solar resources to our system in 2016 to take advantage of the 30 percent Federal Investment Tax Credit (ITC) in achieving compliance with Minnesota's Solar Energy Standard (SES). The Commission made its determination on February 12, 2015, requiring the Company to add all 187 MW from the three identified projects.[8]

On January 16, 2015, the Commission issued its NOTICE requiring the Company to supplement its Resource Plan with a revised Preferred Plan that incorporates the resource decisions made in the CAP proceeding by March 16, 2015. As noted above, the updated Preferred Plan we discuss in this Supplement includes outcomes from various regulatory proceedings and additional modeling and discussion that resulted from our stakeholder engagement.

The balance of this Supplement is organized in a similar manner to our Initial Filing. We additionally provide an Appendix containing the more detailed Tables and Figures that were impacted by the updated modeling, as well as other supplemental information.

III. UPDATED MINIMUM SYSTEM NEEDS

In this section, we discuss how we have incorporated the various resource changes and additions and reexamine system needs under these new assumptions. Except for the resource additions discussed in this section and updated assumptions described in the Appendix, our underlying forecast and other assumptions remain the same as in our January 2, 2015 filing.

Based on updated information, we added the following resources into our minimum system needs analysis:

A. Resource Changes and Additions

1. Natural Gas Resources

Calpine MEC II. The Calpine MEC II combined-cycle generating facility has a nameplate-rated capacity of 345 MW. For purposes of modeling, we have assumed an Unforced Capacity Rating (UCAP) of 278 MW of accredited capacity in 2019.[9]

[8] Order pending.
[9] All referenced and modeled UCAP values use the Unit's summer rating.

Xcel Energy Black Dog 6. The Xcel Energy Black Dog 6 combustion-turbine generating facility has a nameplate-rated capacity of 232 MW. For purposes of modeling, we have assumed a UCAP of 208 MW of accredited capacity in 2019.

2. Solar Resources

Geronimo Aurora. We have accelerated the addition of 100 MW (nameplate) utility-scale solar in 2016[10] to reflect the addition of the Aurora project to our system and removed a corresponding 100 MW of generic utility-scale solar resources in 2024 as appropriate, thereby leaving the total utility-scale solar resource additions in the planning period at approximately 1,700 MW.

Solar RFP Portfolio. The Marshall Solar, MN Solar I and Northstar Solar projects are expected to be online before the end of 2016. The Commission's decision in the Solar RFP proceeding confirms the assumption in our Initial Filing that we would add a combined 187 MW (nameplate) utility-scale solar resources in 2016.[11] Therefore, there is no incremental capacity impact of these resources in this Supplement.

Community Solar Gardens. Our analysis in the initial Resource Plan filing identified a total of 700 MW of small solar – which included CSG, Solar*Rewards and Made in Minnesota – to be added to the system evenly over the 15 years of the planning period. Given the robust response to the CSG program, our updated analysis adds 200 MW (nameplate) of the total 700 MW of small-scale solar resources to the pre-2020 timeframe, resulting in small solar additions of 300 MW from 2015 to 2020 instead of our initial 100 MW assumption. We removed 200 MW of utility-scale solar as appropriate to adjust for those earlier additions.[12] The specific timing and scale of those distributed solar additions are described in Section III of the Appendix.

We determined for this Supplement that a 200 MW increase reflects our best estimate of solar additions through the CSG program based on our interpretation of the enabling statute and its 1 MW garden size limit. Approximately 80 MW of the initial applications we received fell under the 1 MW garden threshold. The remaining 120 MW that we added to our pre-2020 assumptions in this Supplement represent our best forecast of the additional applications we may receive in this period. We acknowledge, however, that there is an effort underway to refine the program rules that could impact this forecast. In our Preferred Plan we made a corresponding 200 MW reduction of utility-scale solar resources in the remainder of the planning period,

10 Recognized by MISO as accredited capacity (UCAP) of 70 MW beginning in 2018.
11 Recognized by MISO as accredited capacity beginning in 2018.
12 Except in those scenarios (notably the Reference Case and North Dakota key scenarios), where there was not any large scale solar additions in the later years of the planning period.

leaving the total small-scale solar resources additions in the planning period at approximately 700 MW.

B. Updated Loads and Resources Analysis

We next incorporated the new assumptions discussed above into our Loads and Resources analysis, which is otherwise consistent with the assumptions and methodology we presented in our Initial Filing. Table 1 below provides our updated minimum system Loads and Resources for the planning period that reflects the resource changes and additions we outlined above. The "Net Resource (Need)/Surplus" values in Table 1 represent the same capacity long/short position over the planning period as presented in the Initial Filing; all resources that follow constitute those added as part of this Supplement.

Table 1: Updated Load and Resources[13] (MW)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecasted Load	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 Load	8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
MISO Planning Reserve	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
Obligation	9,607	9,691	9,764	9,818	9,843	9,863	9,924	9,919	9,937	9,969	10,041	10,136	10,313	10,328	10,430
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
Coal	2,372	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
Nuclear	1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Natural Gas	3,451	3,476	3,476	3,465	3,465	3,465	3,465	3,465	3,137	2,824	2,298	2,047	1,812	1,812	1,812
Biomass/RDF/Hydro/ Wind	1,341	1,339	1,316	1,279	1,205	1,437	1,430	1,383	1,310	461	451	407	318	300	299
Solar *	25	131	137	143	149	156	165	175	187	202	221	242	269	301	339
Existing Resources	9,846	10,004	9,999	9,970	9,913	10,164	10,176	10,150	9,772	8,628	8,106	7,827	7,526	7,536	7,569
Net Resource (Need)/Surplus	239	313	235	152	71	301	252	232	(165)	(1,341)	(1,935)	(2,308)	(2,787)	(2,793)	(2,861)

* *Solar included in the January 2, 2015 Resource Plan filing represented forecasted solar, as represented in the Solar RFP (Docket No. E002/M-14-162).*

	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 MEC2	0	0	0	278	278	278	278	278	278	278	278	278	278	278	278
Geronimo	0	0	70	69	69	69	68	68	68	67	67	67	66	66	66
Small Solar SES - Additions**	-1	-1	0	1	3	4	4	4	4	4	4	4	4	3	3
CSG - Additions**	20	36	53	72	94	103	103	102	102	101	101	100	100	99	98
Additional Resources	20	36	123	628	649	658	657	656	655	654	654	653	652	651	650
Updated Position	260	349	358	780	720	958	909	888	491	-686	-1,281	-1,656	-2,135	-2,142	-2,211

** *Solar Additions represent the revised solar implementation due to Community Solar Gardens (CSG).*

When compared to the Loads and Resources we provided in our initial Resource Plan filing, which anticipated a net surplus through 2023, we now anticipate a net surplus situation through 2024 – with all preceding years having a larger surplus due to the additional natural gas and solar resources in the early years of the planning period.

---

[13] All numbers referenced are UCAP values and use the units' summer rating.

IV. UPDATED REFERENCE CASE

As described in our Initial Filing, we utilize our minimum system needs analysis to develop a Reference Case against which we can measure the performance of other analyzed expansion plan scenarios. Our Reference Case analysis utilizes the same goals and assumptions, such as meeting our renewable energy standard (RES) requirements, utilized in our Initial Filing, except for the changes in system resources described above.

Our analyses and the resulting Reference Case take a conservative approach by making resource additions in light of fluctuations in load forecasts and MISO's evolving reserve margin requirements. As was reflected in the CAP proceeding, this view ensures sufficient capacity to avoid incurring a shortfall, which is valuable in light of fluctuating resource needs assessments. Consequently, we present our updated Reference Case, which preserves the additional system capacity made available by the CAP resources. An alternative resource planning analysis, without that view toward preserving the system surplus that the CAP proceeding additions provide, would show the same expansion plan, because the Strategist model still chooses those least-cost resources to meet any resource needs.

Table 2, below, provides our updated Reference Case Expansion Plan.

Table 2: Updated Reference Case Expansion Plan
(MW Additions, Nameplate Ratings)

Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Small Solar*	43	45	45	48	52	57	12	12	12	12	12	12	12	12	12	12	409
Large Solar	-	-	287	-	-	-	-	-	-	-	-	-	-	-	-	-	287
Wind	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	400
CT	-	-	-	-	232	-	-	-	-	-	690	690	460	-	-	-	2,072
CC	-	-	-	-	345	-	-	-	-	-	-	-	-	778	-	-	1,123

** Small solar is net additions.*

For reference, we provide our Reference Case from our Initial Filing below as Table 3.

Table 3: Initial Filing Reference Case Expansion Plan
(MW Additions, Nameplate Ratings)

Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Small Solar*	18	18	14	13	13	13	13	13	13	13	13	13	13	13	13	13	219
Large Solar	-	-	187	-	-	-	-	-	-	-	-	-	-	-	-	-	187
Wind	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	400
CT**	-	-	-	-	-	-	-	-	-	230	1,150	690	-	230	-	-	2,300
CC	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	778

** Small solar is net additions.* *** Updated CT ratings from UCAP (January 2) to ICAP values.*

Due to the resource additions in the CAP proceeding, the updated Reference Case includes an earlier addition of 200 MW small-scale solar to reflect the response to our CSG program, the addition of 100 MW of utility-scale solar in 2017 to reflect the Aurora Solar project, and the addition of a 232 MW combustion turbine (CT) in 2019 to reflect Black Dog 6 project. Additional CT and CC natural gas plants in the later years of the planning period were adjusted based on the additional capacity added in 2019.

V. UPDATED PREFERRED PLAN

Our updated Preferred Plan is intended to address the same goals that we described in our Initial Filing, namely: achieving over 40 percent CO_2 reduction from 2005 levels by 2030; providing for strategic flexibility to address an uncertain planning landscape and an evolving NSP System through limiting overall reliance on gas as a fuel; adding significant renewable energy to the NSP System; and limiting cost impacts to customers.

The Preferred Plan we outlined in our Initial Filing built upon a strong foundation that we have created through our current investment cycle. Our updated Preferred Plan is a result of additional analysis we performed to test our initial Preferred Plan with new assumptions and additional scenarios. New assumptions underlying the development of our Preferred Plan include the Commission-approved resource additions and changes we describe above. We have also analyzed three scenarios including the potential to retire Sherco Units 1 and 2 in 2020 and 2023, in addition to the Sherco shut-down scenarios we analyzed in our Initial Filing. We discuss this analysis further in Section VIII.

After analyzing the resource changes and additions that are the subject of this Supplement, we determined that only minor changes to our Initial Preferred Plan were warranted. Our analysis continues to indicate that our updated Preferred Plan is the best way to cost-effectively meet our customers' needs and renewable energy requirements while achieving additional environmental policy goals. The addition of the CAP natural gas resources early in the planning period aids in meeting the challenges of the planning landscape described in our Initial Filing, but does not fundamentally change our Preferred Plan – as those resources are being added to our system to meet a prescribed need. Importantly, our Preferred Plan continues to achieve over 40 percent CO_2 emissions reduction by 2030 in a cost-effective manner, while maintaining needed flexibility.

To achieve these goals and mitigate our gas exposure during the planning period at the same time we add significant renewable energy to the NSP System, our updated Preferred Plan continues to focus on low-cost natural gas capacity by adding combustion turbine (CT) peaking facilities. As discussed in our Initial Filing, this will provide the flexibility to evaluate combined cycle (CC) replacements for key facilities beyond the planning period without significantly shifting our resource mix to be heavily reliant on natural gas-fired CC generation. To these ends, our updated Preferred Plan continues to assume the operation of Sherco Units 1 and 2 through the planning period, so that the low-cost, baseload energy provided by these units can continue to benefit our customers.

Table 4 below presents an updated view of the amount and timing of resource additions we propose in our Preferred Plan.

Table 4: Updated Preferred Plan Expansion Plan
(MW Additions, Nameplate Ratings)

Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Small Solar*	43	45	45	48	52	57	15	18	22	27	32	39	47	57	68	82	697
Large Solar	-	-	287	-	-	-	-	-	-	-	300	200	200	500	-	200	1,687
Wind	-	-	-	-	-	600	-	-	200	-	600	-	400	-	-	-	1,800
CT	-	-	-	-	232	-	-	-	-	-	460	460	230	230	-	-	1,612
CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	345

** Small solar is net additions.*

For reference, we present our Initial Preferred Plan in Table 5 below.

Table 5: Initial Preferred Plan Expansion Plan
(MW Additions, Nameplate Ratings)

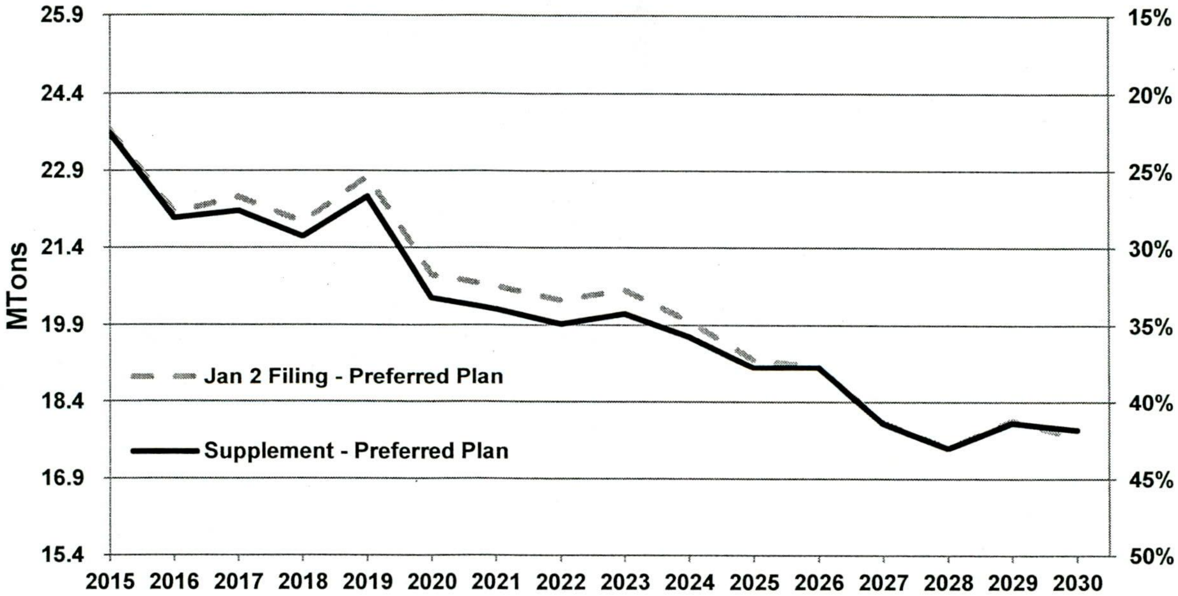
Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Small Solar*	18	18	14	13	13	13	16	19	23	28	33	40	48	58	59	83	506
Large Solar	-	-	187	-	-	-	-	-	-	100	400	300	200	500	-	200	1,887
Wind	-	-	-	-	-	600	-	-	200	-	600	-	400	-	-	-	1,800
CT**	-	-	-	-	-	-	-	-	-	-	920	460	230	230	-	-	1,840
CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

** Small solar is net additions.* *** Updated CT ratings from UCAP (January 2) to ICAP values.*

The CAP proceeding resources additions were included in all our scenarios, so the updated Preferred Plan expansion plan and updated Reference Case Expansion Plan show the same acceleration of small solar by 2020, this time offset by a reduction in large solar additions in 2024 and 2025, so that the total solar additions in the Preferred Plan remain approximately 2,400 MW. Natural gas CT additions are reduced in the later years of the planning period to adjust for the addition of the Black Dog 6 project. The addition of the Calpine plant adds 345 MW of nameplate CC capacity that was not in the initial Preferred Plan.

Figure 1 below demonstrates the comparative ability of our updated Preferred Plan and Initial Preferred Plan to achieve our CO_2 reduction goals:

Figure 1: Preferred Plan CO_2 Emissions – NSP System
Initial Compared to Updated



We note that our five-year action plan remains the same as our Initial Filing, acknowledging the CAP and CSG additions discussed earlier in this Supplement.

With regard to the long-term outlook, by 2020 we expect we will have achieved a 33 percent CO_2 reduction from 2005 levels, adding 520 MW of renewable resources and positioning us to achieve over 40 percent by 2030. We will largely achieve this by adding approximately 3,700 MW of new renewables during the 2020-2030 time period, including 1,800 MW of non-Production Tax Credit (PTC) wind, 1,400 MW of utility-scale solar resources, and approximately 470 MW of small-scale solar resources as distributed generation.

The resource additions and changes we incorporate in this Supplement do not change the technologies, alternatives, and steps we discussed in our Initial Filing that we are considering to address the opportunities and barriers associated with continuing to make progress toward achieving the state greenhouse gas emission reduction goals established in Minn. Stat. § 216H.02, subd. 1.[14]

[14] See Appendix D of our Initial Filing for additional detail on the Company's status relative to the 2015 and 2025 CO_2 reduction goals, and the costs, opportunities, and technical barriers relative to the 2050 goal.

VI. UPDATED RESOURCE PLANNING ANALYSIS

As previously noted, this resource planning cycle begins to signal a change in focus away from a more concentrated view of the capacity needs of the system toward a plan that is focused more on a balance between the energy mix of the system, our emission profiles, and the need to retain strategic flexibility to address the evolving planning landscape and evolution of the NSP System. We discussed the Planning Framework, Strategist Assumptions and Sensitivities, and Scenarios Analyzed that formed our Preferred Plan in our Initial Filing, including detailed information in Appendix J to that filing. We also include an abbreviated Appendix to this Supplement that contains some of the more detailed Tables and Figures from our Initial Filing that were impacted by our updated modeling.

Our updated resource planning analysis utilizes the same methodology and concepts we presented in our Initial Filing. In this Section, we first present updates to the assumptions and sensitivities we utilized in our updated analysis. We then discuss updated Sherco retirement scenarios that we have used in developing our updated Preferred Plan. Last, we present our updated resource planning analysis utilizing our updated assumptions, sensitivities and scenarios.

A. Updated Assumptions and Sensitivities

The most significant changes to our assumptions include the addition of the CAP resources as well as changes to our CSG and Sherco retirement assumptions described in this Supplement. Additionally, we provide in Section I of the Appendix an explanation of our underlying wind pricing and CO_2 assumptions in response to stakeholder requests. Except as described in this Supplement and its Appendix, all other assumptions we utilized in our Initial Filing remain the same.

In addition, to help ensure a thorough analysis, we have re-evaluated the Sherco Variable Operations & Maintenance (VOM), Fixed Operations & Maintenance (FOM), and ongoing capital expenditure assumptions for both units based on the earlier retirement dates. These updates are intended to better reflect the impact of a specific retirement date on the Company's operation and maintenance of the plant. For example, if Sherco Units 1 and 2 were to be retired in 2020, we would manage the plant toward retirement during the remaining five years of operations so as to avoid making significant capital investments in the plant. In contrast, a 2030 retirement date would provide an additional 15 years of plant operations, and therefore the Company would make different O&M and capital expenditure decisions to ensure the plant was in good working order for the additional 10 years of operating life. The adjustments that were incorporated into all scenarios in this Supplement are as follows:

- *Variable Operations & Maintenance.* The projected VOM for each unit was adjusted as the result of actual experience of activated Carbon usage for Mercury reduction in 2014. The activated Carbon injection systems (ACI) were placed in service late in 2014, giving us a year's worth of operating experience to better inform our assumption. The actual injection rate of activated Carbon was significantly lower than originally predicted, so the VOM budget was reduced as a result.

- *Fixed Operations & Maintenance.* The projected FOM had been based on the 2014 budget. The Strategist model was escalating the FOM from 2014 at 2.5 percent per year. We determined that the FOM for each unit is cyclic over the three-year overhaul cycle and that the budget through 2030 already includes escalation at approximately 1 percent per year. Also, when a unit retires, the common FOM must be reallocated to the remaining units at the site. We identified that the retired units(s) would need to be available for the capacity market until May 31 of the year they were taken out of service. In order to accommodate this need, five months of FOM plus the severance and decommissioning costs were calculated for the year following shutdown. The cyclic FOM values were established to account for these items.

- *On-Going Capital Expenditures.* The long-term capital needs of the units were re-evaluated on the basis of a potentially shorter operational life. The capital investment in the Units drops off significantly as the capital recovery period shortens. The original Reference Case capital was based on keeping the Units reliable until 2040. The shortened time periods of 2020, 2023, and 2030 resulted in a number of larger capital replacement projects being taken out of the long-term budgets.

The impacts of these updated assumptions are reflected in the updated summary tables included in Section IV of the Appendix.

B. Additional Sherco Retirement Scenarios

Our updated Resource Plan includes an alternative resource planning economic analysis of additional Sherco retirement scenarios. In our Initial Filing, we had interpreted the Commission's Order in our last resource plan docket to require us to analyze only scenarios we deemed feasible, and therefore provided Sherco retirement scenarios that assumed retirement no earlier than 2025. While we continue to believe that any retirement of a Sherco Unit prior to 2025 presents significant technical challenges, we provide the economic analysis of 2020 and 2023 retirement scenarios in this Supplement.

By way of background, our Initial Filing provided that in our early Sherco retirement scenarios, 2025 represented the earliest reasonably practicable retirement timeframe. In response to an information request from the Clean Energy Organizations, we provided further explanation that replacement generating capacity would require a number of steps, including a resource acquisition process or RFP, contract negotiation and approval, siting and environmental permitting, transmission and gas infrastructure development, and construction of the facility. Based on previous experience, we estimated that process could take up to eight years. We therefore estimated that the earliest possible retirement date to replace 750 MW or 1,500 MW of generating capacity at Sherco would be in the 2023-2025 timeframe.

In addition to the time necessary to identify, develop, and in-service replacement generation for the retirement of one or two Sherco Units, we anticipated that a 2025 timeframe would have been the earliest retirement date that would provide sufficient time to identify and resolve the technical challenges involved with retiring these key generating units. Our review has determined that an accelerated retirement timeline could present significant challenges to system reliability and operations, which will likely require more than a mere economic analysis and generic replacement of capacity and energy. We discuss these challenges further in Section VIII.

Our Initial Filing included 19 scenarios illustrating a pre-2030 retirement of one or both Sherco units with various mixes of replacement capacity. Our Initial Filing also included scenarios that installed selective catalytic reduction technology (SCRs) in 2024 and 2025 on Sherco Units 1 and 2, with continued operations through 2030. As part of this Supplement, we have included additional Sherco retirement scenarios utilizing a 2020 and 2023 timeframe. The table below provides details on those new Sherco retirement scenarios included in our updated analysis. A full summary of the scenarios modeled for this Supplement is included in Section II of the Appendix. For the purpose of this Supplement and arriving at our updated Preferred Plan, we analyzed these eight scenarios, as well as two PTC variations and a North Dakota scenario that is compliant with North Dakota law and its energy policies.

Table 6: Sherco Retirement Scenarios[15]

#	Scenarios	Modeling Termination Date		SCRs-Units / Years	Replacement
		SH1	SH2		
1	Updated Reference Case	2030	2030	None	Outside the planning period
1B	Updated Reference Case with SCRs	2030	2030	Unit 1- 2024 Unit 2- 2025	Outside the planning period
2-5C	Updated Sherco Retirement Case- 1 Unit 2025	2030	2025	None	Various scenario options- CC, CT, 50% or 75% renewables
6-9C	Updated Sherco Retirement Case- 2 Units 2025	2025	2025	None	Various scenario options- CC, CT, 50% or 75% renewables
10	Updated Preferred Plan	2030	2030	None	Outside the planning period
16-19C	New Sherco Retirement Case- 1 Unit 2020, 1 Unit 2030	2030	2020	None	Various scenario options- CC, CT, 50% or 75% renewables
24-27C	New Sherco Retirement Case- 1 Unit 2020, 1 Unit 2023	2023	2020	None	Various scenario options- CC, CT, 50% or 75% renewables
20-23C	New Sherco Retirement Case- 2 Units 2020	2020	2020	None	Various scenario options- CC, CT, 50% or 75% renewables

C. Resource Planning Economic Analysis

We performed our updated resource planning analysis in largely the same manner we described in our Initial Filing. However, we were mindful of taking a conservative approach to ensuring adequate resources on our system in light of fluctuating demand forecasts, as discussed above. Therefore, our updated analysis assumes we will maintain the additional capacity provided by the resource additions approved in the CAP through the early years of the planning period, rather than offsetting the resource additions through reduced capacity elsewhere. That analysis is identified as "Conservative Results" and "Conservative Ranking" in the tables below. We have also performed an analysis under an alternative planning approach where the additional capacity provided by the CAP resources would be utilized to replace a single Sherco

[15] In each of the Sherco retirement scenarios in this Supplement, we assume that the units will be providing capacity through May of the year after indicated retirement. This is done in order to meet the criteria from MISO to qualify for the capacity market, which says that the units must maintain an operating and maintenance staff in place through the current MISO planning year to sustain capacity eligibility for these resources. We assume a 100% outage rate (i.e. the unit does not run) for January-May of the following year, but we incur Fixed O&M for staffing to maintain capacity accreditation.

Unit, which is identified through the "Alternative Results" and "Alternative Ranking" columns in Table 7.

To undertake our updated resource planning analysis in fundamentally the same manner set forth in our Initial Filing, we began by analyzing the different scenarios from a Present Value Societal Cost (PVSC) basis that includes the same value for CO_2 emissions we utilized in our Initial Filing. The PVSC results provide a baseline ranking of the overall societal benefits of each of the different scenarios analyzed. Because actual impact to our customers is a key component of our planning framework, and because not all states we serve allow for an analysis that includes externalities, we also performed a least-cost analysis on a Present Value of Revenue Requirements (PVRR) basis that does not include carbon costs.

After performing the alternative PVSC and PVRR analyses, we proceeded to evaluate each of the scenarios more holistically utilizing the "Run Key" approach we utilized in our Initial Filing. This type of analysis provides a comprehensive view of the different scenarios analyzed with respect to their environmental performance, strategic flexibility, and cost. As explained in our Initial Filing, the Run Key carries forward the PVSC and PVRR ranking of each scenario to provide a reference point for the broader analysis and identifies key policy outcome metrics such as CO_2, and strategic flexibility indicators such as "gas burn" (which is the amount of gas as fuel that would be consumed under a particular scenario). The Run Key also includes the change in capacity factors of our existing coal fleet between the Reference Case and each scenario. This metric provides a way to measure the impact of each scenario on the installed capacity and low-cost energy provided by these key units.

Table 7 below provides the PVSC outcomes of key scenarios and the resulting ranking of the scenarios on a PVSC basis.

Table 7: PVSC Results ($Millions) and Rankings

Scenarios	Conservative Results	Conservative Ranking	Alternative Results	Alternative Ranking
Updated Reference Case	$52,464	8	$52,422	9
Updated Reference Case with SCRs	$52,740	11	$52,698	11
Updated Preferred Plan	$52,119	3	$52,083	3
Updated Preferred Plan with PTC	$51,298	1	$51,262	1
Updated Sherco Retirement Case - 1 Unit 2025*	$52,223	4	$52,187	5
Updated Sherco Retirement Case - 1 Unit 2025 & PTC*	$51,402	2	$51,366	2
Updated Sherco Retirement Case - 2 Units 2025*	$52,435	7	$52,399	8
New Sherco Retirement Case - 1 Unit 2020, 1 Unit 2030*	$52,258	5	$52,159	4
New Sherco Retirement Case - 2 Units 2020*	$52,488	9	$52,399	7
New Sherco Retirement Case - 1 Unit 2020, 1 Unit 2023*	$52,429	6	$52,330	6
Updated North Dakota Plan	$52,723	10	$52,620	10

* *Resource additions identical to Preferred Plan.*

As shown in Table 7, scenarios capturing PTCs provide the best overall value on a PVSC basis. However, we also analyzed other highly-ranked scenarios, because the continued availability of PTCs is uncertain. Of the non-PTC scenarios, our updated Preferred Plan performed best on a PVSC basis. And consistent with our Initial Filing, our Preferred Plan with the retirement of a single Sherco Unit in 2025 performed second best. The additions of the CAP resources, along with the updated Sherco and externality assumptions, account for an overall increase in the PVSC costs. The scenario ranking is relatively unchanged between the conservative and alternative views, although the additional Sherco retirement case of one unit in 2020 and one in 2030 is slightly more cost effective and in fact only feasible in the scenario where CAP resources are available to offset the capacity reduction.

Table 8 below identifies the PVRR results of these key scenarios and the corresponding ranking of the scenarios on a PVRR basis.

Table 8: PVRR Results ($Millions) and Rankings

Scenarios	Conservative Results	Conservative Ranking	Alternative Results	Alternative Ranking
Updated Reference Case	$45,647	4	$45,605	4
Updated Reference Case with SCRs	$45,923	5	$45,882	5
Updated Preferred Plan	$45,960	6	$45,924	6
Updated Preferred Plan with PTC	$45,216	1	$45,181	1
Updated Sherco Retirement Case - 1 Unit 2025*	$46,206	7	$46,170	7
Updated Sherco Retirement Case - 1 Unit 2025 & PTC*	$45,462	2	$45,426	2
Updated Sherco Retirement Case - 2 Units 2025*	$46,636	9	$46,600	9
New Sherco Retirement Case - 1 Unit 2020, 1 Unit 2030*	$46,370	8	$46,272	8
New Sherco Retirement Case - 2 Units 2020*	$46,971	11	$46,878	11
New Sherco Retirement Case - 1 Unit 2020, 1 Unit 2023*	$46,798	10	$46,699	10
Updated North Dakota Plan	$45,517	3	$45,473	3

* *Resource additions identical to Preferred Plan.*

Table 8 indicates that from a strictly PVRR perspective and absent PTCs, the North Dakota Plan continues to be the lowest-cost plan under certain circumstances, since it relies most heavily on natural gas generation additions compared to the Preferred Plan or Reference Case. Table 8 also indicates that our Reference Case scores the next best on a PVRR basis. Our updated Preferred Plan fared well, and was reasonably close in cost to those scenarios ranked above it. And because our Preferred Plan provides the flexibility to take advantage of PTCs if they should become available, this Plan further serves our customers well under multiple circumstances. While the costs for all of the plans were slightly higher in our conservative approach compared to an alternative approach that does not preserve the greater capacity from CAP resource additions, the scenario rankings in both the conservative and alternative review are unchanged.

Table 9 below provides our updated Run Key.

Table 9: Run Key

	PVRR Ranking*	PVSC Ranking	2030 Coal Gen vs. Ref Case*	2030 Gas Burn (Bcf)*	2030 Percent CO2 Reduction**	Total Renewable Additions (MW)
Updated Reference Case	4	8	-	65	25%	1,096
Updated Reference Case with SCRs	5	11	-0%	65	26%	1,096
Updated Preferred Plan	6	3	-12%	33	43%	4,184
Updated Preferred Plan with PTC	1	1	-12%	33	43%	4,184
Updated Sherco Retirement Case- 1 Unit 2025	7	4	-35%	57	51%	4,184
Updated Sherco Retirement Case- 1 Unit 2025 & PTC	2	2	-35%	57	51%	4,184
Updated Sherco Retirement Case- 2 Units 2025	9	7	-61%	86	60%	4,184
New Sherco Retirement Case- 1 Unit 2020, 1 Unit 2030	8	5	-32%	58	49%	4,184
New Sherco Retirement Case- 2 Units 2020	11	9	-59%	87	59%	4,184
New Sherco Retirement Case- 1 Unit 2020, 1 Unit 2023	10	6	-59%	87	59%	4,184
Updated North Dakota Plan	3	10	+3%	76	21%	287

* For No CO2 dispatch cost sensitivity.
**For No CO2 dispatch cost sensitivity, CO2 reduction is from 2005 levels.

The Run Key analysis continues to demonstrate that our updated Preferred Plan best meets our goals of at least 40 percent carbon reduction by 2030; maintaining strategic flexibility by minimizing reliance on gas as fuel; and adding significant renewable energy to the NSP System. The renewables additions have increased in the Reference Case and North Dakota scenarios due to the utility-scale solar additions, but are largely unchanged in the other scenarios, as they reflect the resource additions in the Preferred Plan that reduced the large solar additions in the later years of the planning period to offset the earlier additions due to CSG. Carbon emissions reductions are greater in all scenarios included in this Supplement, as compared with the Initial Filing.

Importantly, none of the three new Sherco retirement scenarios outperform any of the scenarios we initially analyzed and which were updated in this Supplement. While these new scenarios appear more cost effective from a PVSC perspective as compared to the PVRR analysis, we must balance those environmental criteria with impacts to customers. We note that the additional capacity acquired through the CAP proceeding provides a slight surplus in the early years of our plan, which may allow for a slightly earlier retirement date for a single Sherco Unit based solely on a loads and resources perspective. However, the additional capacity acquired through the CAP proceeding is not sufficient to replace the 1,500 MW of generating capacity lost through retirement of both Sherco units, and indeed a CT or renewable energy replacement would not be technically feasible to substitute for the system-wide capabilities that Sherco provides. We discuss the details of this further in Section VIII.

VII. CUSTOMER COST IMPACTS

We note the CAP and CSG resources increase our baseline costs early in the planning period. Since they are baseline costs, these increased costs are carried through all of our analyses.

We have received feedback from stakeholders asking that we provide an updated view of the cost impacts of our Preferred Plan that is more representative of our five-year plan, similar to what Minnesota Power provided in its last resource plan. We are in the process of compiling such an analysis, with total Revenue Requirements and incremental impacts of the Preferred Plan, which we will submit later in this proceeding and share with stakeholders through our ongoing outreach efforts.

VIII. SHERCO RETIREMENT CONSIDERATIONS

Many times decision-making processes in the evaluation of resource plans center around economic modeling information that compares one scenario or outcome to another. This type of numerical comparison is appropriate when resource planning decisions are focused on which resource to add to meet system growth while the existing system essentially stays intact. However, in considering options to retire and replace key components of the existing system, the analysis must take into account a number of additional considerations not always captured in economic models. Great care must be taken to gather all of the data to account for other variables associated with these real world issues.

Other key considerations associated with removing or replacing key generation assets on the system are both technical and policy-based. From a technical perspective, it is necessary to evaluate these decisions on the utility's ability to provide reliable electric service to customers. As we outline in this section, it will be essential to consider technical impacts such as the role the Units play in balancing the flow of generation to and from North Dakota and around the region; their impact and role in maintaining system stability; their key role in our Black Start operational plan; and their unique operating characteristics that allow them to provide ancillary services. Important policy considerations include ensuring that Minnesota obtains the appropriate credit for any action given the emerging Clean Power Plan regulations; local and statewide impacts stemming from a Unit shut-down or relocation; and ensuring the location of the replacement supply source meets the needs of all NSP System customers.

A. Sherco Units 1 and 2 Play an Important Role on the Grid

The ability to provide reliable electric service depends on a complex and interconnected network of generating resources and transmission infrastructure that provides capacity and delivers energy to customers. Each resource and system component in the network plays a unique role based on its size, type and location on the system. Sherco Units 1 and 2 are no different. In fact, the upper Midwest system, and certainly the NSP System, has grown up around Sherco Units 1 and 2, and relies on the unique aspects of these Units to not only generate capacity and energy for our customers, but also to provide numerous essential system benefits. Therefore, the potential retirement of one or both of these Units must consider more than replacement of their MW output.

These technical issues are not unique to the Company. The industry is just beginning to explore the topic of the cumulative effect of retirement of multiple large generation units that provide essential support to the transmission grid, assisting it in maintaining operating reliability. The North American Electric Reliability Corporation (NERC) is in the process of undertaking reliability studies in the next year to inform the industry of the impacts from the retirement of multiple large generating units – like Sherco 1 and 2 – in light of the potential impact of the U.S. Environmental Protection Agency's (EPA) proposed Clean Power Plan on these large generating stations.

Historically, the industry has studied the electric grid in one- to ten-year timeframes, assuming all existing baseload generation continues to operate throughout the planning horizon. This is consistent with the Minnesota Renewable Energy Integration and Transmission (MRITS) study[16] performed recently in Minnesota to assess the potential impact of raising Minnesota's renewable energy standard to 40 percent, which also assumed all baseload generation would remain on the system. As an industry and a Company, we have not yet performed the studies necessary to fully understand the technical impacts of retirement of multiple large generation units.

Before embarking on the path of retiring one or both of the Sherco 1 and 2 Units, it will be critical to understand the technical implications and identify and address any mitigating measures that must be undertaken. For example, our initial assessment determined that replacing the baseload energy from Sherco Units 1 and 2 with

[16] *Report: In the Matter of the Integration and Transmission Study for the Future Renewable Energy Standard Required by Minnesota Laws 2013, Chapter 85, Article 12, Section 4, Directed by the Minnesota Department of Commerce-Division of Energy Resources*, MPUC Docket No. E999/CI-13-486 (November 5, 2014).

renewable energy facilities is likely infeasible from a reliability perspective. Rather, it is more likely than not that any replacement capacity of Sherco Units 1 and 2 will require the installation of thermal resources.

Toward this end, we have retained an independent, third-party expert to study the effects of potential phased retirement of one or both Sherco Units on the transmission system in 2020 and 2023 – or full retirement of these Units at or after the end of the planning period. We will also analyze what the impacts of a possible future shutdown of the Monticello plant, the other large generating unit located in Sherburne County, in 2030 could mean. We believe the expanded study scope from our third-party expert will allow us to coordinate the considerations related to these two baseload resources operating in relative proximity to each other.

Additionally, these decisions cannot be made in isolation. The MISO Tariff requires that any generation retirement be studied and approved by MISO to ensure that it results in no adverse effects to the reliability of the system.[17] We have initiated the process under Attachment Y-2 of the MISO Tariff to begin a non-binding, informational study that will identify any reliability impacts of a potential future status change to one or two Sherco Units.

We discuss our technical study efforts, the unique attributes Sherco Units 1 and 2 provide the NSP and MISO systems in maintaining system stability and reliable service to customers, and various policy and other replacement considerations that must be considered and evaluated to ensure we are able to continue to provide customers with reliable electric service.

1. Overview

The Sherco Generating Station is the largest power station in the Midwest, consisting of three units that have a total nameplate capacity of 2,400 MW. Units 1 and 2, which were the focus of a July 2013 Life Cycle Management analysis[18] and continue to be a focus of this Resource Plan, are wholly Company-owned baseload facilities with a nameplate generating capacity of 750 MW each for a total of 1,500 MW. Units 1 and 2 were constructed in the 1970s, and provide low-cost energy and key reliability support to the NSP System and the MISO region. The NSP System has been developed around these Units for almost 40 years, and our design and analysis of resource

[17] MISO Tariff Section 38.2.7.
[18] *In the Matter of Xcel Energy's Life Cycle Management Study for Sherco 1 & 2*, MPUC Docket No. E002/RP-13-368, (July 1, 2013).

additions and transmission expansions all assumed that these Units would be in place to continue to support the system

It is these Units' size, location, and operating characteristics that require important technical study to be sure that we fully understand the implications of potentially removing one or both of them from the NSP and MISO systems.

2. *Unit Size Provides System Stability*

At its core, to preserve system stability and customer reliability the system must balance generation with changing load conditions and fluctuations caused by other disturbances. The large generating units on the system afford the capability to "ride through" these frequency disturbances by virtue of their sheer mass. Without the inertia, or resistance to a change in state of motion, afforded by these large units, system stability could be at risk. If system frequency drops too low, protective devices will disconnect generating units from the rest of the system to protect them from damage. These disconnections further exacerbate any imbalance between load and generation, which causes further disconnections and shedding of load.

The frequency regulation of the transmission system is governed by the connected generating units. Sherco Units 1 and 2 provide the spinning mass that assists in maintaining the 60 hertz frequency for the region. They are uniquely able to do this because of their size and operating characteristics, which include the ability to quickly increase or decrease their output in response to system conditions.[19]

At this time, no comprehensive studies have been conducted that examine the impact of permanently removing individual large generating facilities, such as Sherco Units 1 and 2, from the system at the same time significant renewable, variable resources are being added. Nor have any studies examined removal of numerous large generating facilities on an interconnected system, such as MISO, which is a potential outcome of EPA's 111(d) Rule. The studies we have initiated, and that otherwise are appearing to be initiated nationally, will provide essential information and insights into the implications of retiring these large generating units on system stability and reliability.

3. *Unit Location Provides Important Grid Support*

Both the Company's Sherco Plant and Monticello Nuclear Generating Plant are located in Sherburne County, making the location of these large, baseload generating facilities a very important consideration in maintaining system stability and reliability.

---

[19] Sherco Units 1 and 2 are able to respond at 10 MW per minute.

Together, these plants total over 3,000 MW of nameplate capacity, or about 30 percent of the Company's total existing generating capacity. With the concentration of so much generation in one geographic area, the electrical performance of the regional transmission system – and the entire mix of resources on the NSP System – is fundamentally architected around these units.

In fact, Sherburne County is the generation center nearest to the generation center in western North Dakota, and is therefore an important area to provide grid support and balance the flows of generation to and from that area. We note that Sherco Units 1 and 2 are also the sole supply of steam to the Liberty paper mill. The current steam supply agreement with the adjacent paper recycle mill calls for 108,000 pounds per hour of process steam with an allowed down time of 17 hours per year, which requires both Sherco Units 1 and 2 to maintain this level of reliability. The current contract runs through 2020 and can be renewed through mutual agreement.

4. Sherco Units 1 and 2 are Central to Black Start Capabilities

In addition to assisting in maintaining the frequency for the region because of their size and operating characteristics, Sherco Units 1 and 2 are the primary Targets, or first Units to be repowered, as part of our Black Start Plan. A black start is the process of restoring a power station to operation without relying on the external transmission network. Normally, the electric power used within the plant is provided from the station's own generators. If all of the plant's main generators are shut down, station service power is provided by drawing power from the grid through the plant's transmission line.

However, during a wide-area outage, off-site power supply from the grid will not be available. In the absence of grid power, a so-called black start needs to be performed to bootstrap the power grid into operation. Black Start Plans are required by NERC, and the Company's plan is subject to review and approval by MISO. The NSP System takes the lead in restoring the majority of the Minnesota bulk electric system in a black start event, with our neighboring utilities relying on us to have the larger units to stabilize the grid.

Sherco Units 1 and 2 are the largest units on our system that can be started from our Inver Hills Plant, which is our specially-equipped facility designated for this essential black start function. As discussed previously, large units are needed to maintain system voltage and frequency when recovering from a blackout situation. In addition to its responsiveness to fluctuating loads and resources on the system, the ability of Sherco Unit 1 and 2 to maintain a minimum operating level of approximately 150 MW is also part of the reason that it plays a primary role in our Black Start Plan.

Without Sherco 1 and 2, we would need to devise an entirely new Black Start Plan to identify a different Target facility in the Twin Cities metro area and repowering plan. Again, the type or operating characteristics of the facility are fundamental. As intermittent resources, wind and solar facilities are not dispatchable and have comparatively small generators to be considered sufficiently stable to maintain the system by themselves, and therefore are not eligible to be black start Targets. In order to be an eligible replacement Target, natural gas generating units would require guaranteed firm fuel supplies that are not dependent on the electrical system.[20]

5. *Replacement Capacity and Capabilities are Critical Factors*

The timeline for replacement, as well as the replacement capacity and capabilities, are also critical to ensuring ongoing reliable service to customers.

a. Timeline

Assuming a site with ready access to natural gas and transmission is already identified, we estimate that the physical construction of peaking units, for example, could be completed within three years of approval to proceed; a combined-cycle facility would take at least an additional year to build. However, it is necessary to consider the timeline needed to obtain regulatory approvals, transmission interconnection upgrades, natural gas infrastructure upgrades, and in the case of a greenfield site, acquisition and site permitting, which would add significant time to the development. We discuss the natural gas and transmission interconnection considerations further below.

b. Sufficient Firm Natural Gas Supply

In addition to general availability of natural gas supply to a replacement plant either in-place or at a greenfield site, it is important to consider other issues associated with reliance on natural gas for a replacement thermal unit, which include the following:

Fuel Storage. Coal units typically have in excess of 40 days of fuel stored on-site to allow for interruptions in fuel supply as well as variations in generation demand. The natural gas system has limited storage capability, and fuel demand must be scheduled a day in advance with very limited ability for intra-day adjustments. Further, as noted in conjunction with our discussion regarding a black start event, identification of a

[20] An option proposed in other jurisdictions is to require diesel generator backups at each interstate pipeline compressor station. However, this is a costly and inefficient option given the number of compressor stations typically used by long-line pipelines. This option would likely meet with substantial resistance from existing pipeline customers due to cross subsidy concerns and implementation of such a proposal would probably face lengthy delays.

natural gas-fueled Target would require either having onsite duel (gas/oil) fuel firing capability including onsite oil fuel storage or having the natural gas pipeline company guarantee their ability to provide an uninterrupted supply, including in the case where electrical power for the compressor stations is unavailable from the grid, as would be the case in a black start event.[21]

Fuel Diversity. The natural gas supply infrastructure has limited redundancy as identified in recent NERC studies, and has potential for major supply limitations if a major interstate supply line is interrupted as the result of a line failure or compressor station shutdown.[22]

c. Transmission Interconnection

In the event of a retirement of one or both of the Units, we would maintain grandfather interconnection rights at the Sherco site that could prove valuable if replacement in-place is determined appropriate. Alternatively, if greenfield development is determined most appropriate, as always, transmission access is a significant consideration.

B. Significant Study of Reliability Implications is Necessary

As we have discussed, the transmission reliability implications of potentially retiring Sherco Units 1 and/or 2 (up to half the generation concentrated in the Sherburne County area) must be studied. As noted, we have retained an expert, and also recently requested initiation of a MISO study to examine the impacts of the retirement of one or both Sherco Units. Additionally, we are continuing to monitor national studies on the topic of the cumulative effect of retirement of multiple large generation units that provide inertia to the transmission grid, and we intend to initiate a study to inform our Black Start Plan, examining the feasibility of identifying Targets other than Sherco Units 1 and 2 to kick off the repowering of our system in the event of a blackout or similar significant event on our system.

1. Xcel Energy Transmission Reliability Study

The expert we have retained will study the effects of potential phased retirement of one or both Sherco Units on the transmission system in 2020 and 2023, or full retirement of these units at or after the end of the planning period.

---

[21] This would require the pipeline to maintain some type of backup such as a diesel generator(s), which is something that we are seeing east coast utilities implement in the wake of significant events on their system that had unanticipated consequences such as the loss of natural gas supply.

[22] *Polar Vortex Review, North American Electric Reliability Corporation* (September 2014).

We anticipate this Study would also address the 2030 expiration of our current operating license for the Monticello nuclear plant, in an effort to coordinate the considerations related to all of these baseload resources operating in relative proximity to each other. This Study will include the CAP resources in the underlying powerflow models, and then identify appropriate size, type and locations for replacement capacity. Although some aspects of the study may address issues that will arise closer to or after the end of the planning period, we believe it is important to begin the analysis now in light of the particular interest in Sherco Units 1 and 2 during the planning period.

It is our intent that this Study will provide a baseline understanding of the technical impacts of retiring Sherco Units 1 and 2 and/or Monticello. This Study will also explore potential benefits to diversifying the geographic location of our generating stations. For example, it may make the most long-term sense from a reliability perspective to locate replacement capacity in the Red River Valley area of North Dakota, closer to our North Dakota load, to further geographically diversify our key generating facilities.

2. *MISO Study*

As noted previously, the MISO Tariff requires that MISO study and approve any planned retirement or suspension of a generating unit. Therefore, in addition to performing our own study, we have also requested that MISO study the impacts of the retirement of one or both Sherco Units to determine whether certain retirement timing is feasible – or whether we must continue their operation as System Support Resources. If MISO's analysis indicates that retirement of a particular generator would affect reliability, and that all other options have been exhausted, MISO may order the continued operation of particular generators to support the reliability of the transmission system.

We expect that our study work with MISO and our third-party expert will take up to nine months. We will keep the Commission updated along the way. We will also provide the Commission the results when available and propose next steps based on those results.

C. Policy Considerations

As we discussed in our Initial Filing, this resource plan comes at a time of an uncertain planning landscape. In light of this, early retirement of one or two Sherco

Units raises significant policy challenges in addition to the reliability and development challenges discussed above.

1. Environmental Policy Considerations

Emerging Clean Power Plan regulations have not yet been finalized. We see great value in understanding how the final regulations will impact our fleet – as well as the generating resources in MISO – before making a final decision with respect to Sherco. Whatever the final outcome with respect to Sherco Units 1 and 2, ensuring that retirement of a Unit will be credited against Minnesota's carbon reduction requirements under these emerging regulations will be an important consideration. Without such certainty, we may overcome the challenges of retiring a Sherco Unit, but then need to find further CO_2 reductions elsewhere in Minnesota to meet Clean Power Plan requirements, and could be required to do so in a timeframe that limits our ability to make the best cost and value choices for our customers. At a minimum, we believe it would be most prudent to ensure that we can obtain the regulatory benefits of the retirement of one or both Sherco Units in light of the cost impact on our customers of doing so.

2. Local Impacts

Further, the retirement of one or both Sherco Units would impact not only the over 430 full-time employees at the plant, but also the property tax revenues for the surrounding community. A plan to transition the workforce from Sherco would need to be developed, focused on either laying off workers or migrating them to other plants.[23] As noted previously, Sherco Units 1 and 2 also have a relationship with Liberty Paper to provide steam and power for their operations, which would be lost if the Units were retired. These impacts would need to be balanced against any technical challenges of repowering Sherco and the potential for diversifying the geographic footprint of our generating fleet.

To that end, we have commissioned an economic impact study through the Business Research Division of the University of Colorado Leeds School of Business to examine the economic impacts associated with the retirement of Sherco Units 1 and 2. The Study, which we expect to be completed in June 2015, will look at the influences of various Sherco scenarios on employment, capital expenditures, operating and maintenance costs, property taxes and cost impacts on our customers. It will include

---

[23] We anticipate a retirement of one or both Units would result in the layoff or retirement of over half of the current staff.

various combinations of retirement and replacement scenarios for Sherco Units 1 and 2, using the same data that we used for this Resource Plan Supplement.

3. Divergent State Policies

Last, these policy considerations should be analyzed in an environment of diverging state energy policies. Many of our customers and regulators value the low-cost baseload energy provided by Sherco Units 1 and 2 and would likely raise concerns with the cost impacts of a retirement of these Units earlier than may be necessary. At the same time, they may find value in the potential for locating generation in areas where our load does not have any generation in the area. To arrive at a feasible solution for Sherco, we will need to consider the interests of our customers in all of the states we serve.

Additionally, because the retirement of a Sherco Unit will affect the energy mix and costs to all customers served by the NSP System, we note that it will be necessary to obtain consensus from Commissions in all of the states we serve regarding the appropriate replacement supply units for Sherco.

D. Retirement Alternatives

These technical and policy considerations contribute to our concern regarding the feasibility of retiring a Sherco Unit prior to 2025. As noted above, the need for specific capacity size, type, timing and location of replacement capacity for one or both Sherco Units will create a different paradigm for how resource selections have been completed in the recent past under the Commission's resource planning procedures.

In light of these challenges, we believe there is merit in exploring potential alternatives to the retirement of Sherco Units 1 and/or 2 that would achieve desired environmental outcomes without the loss of these key facilities. Currently, it appears that our stakeholders view the future of Sherco as a binary choice between continued operation or retirement. This does not necessarily need to be the case, and exploration of potential alternatives could be warranted given the technical and policy considerations associated with retiring Sherco Units 1 and 2.

For example, we are exploring the potential to operate our coal fleet as if 750 MW of baseload coal-fired generation was not available, while leaving the Sherco Units in place to continue supporting system reliability. Alternatively, we are analyzing the potential of utilizing Sherco Units 1 and 2 at only minimum necessary levels to retain system reliability. These are only two potential creative alternatives to retirement that could achieve environmental outcomes while retaining the benefits of these Units.

We recognize that many creative alternatives will require collaboration with our stakeholders and MISO, and could well require changes to the MISO Tariff or federally regulated transmission and energy market requirements. However, exploration of these alternatives and their feasibility should be part of any analysis of early retirement of Sherco Units 1 and 2.

IX. STAKEHOLDER COLLABORATION

In our January 2 filing, we proposed a collaborative process to engage stakeholders in a dialogue about resource modeling, sensitivities, and issues arising from the evolving planning landscape. This was in line with the approach outlined in the e21 Initiative report that introduced the concept of Integrated Resource Analysis, which the Company supported in its December 22, 2014 letter.[24] The goal of this stakeholder engagement would be to gather input from stakeholders, determine whether changes to the Plan are needed, and address any advance stakeholder concerns in a proactive, collaborative manner. In its January 16 Notice, the Commission agreed that a stakeholder collaborative would be valuable, and encouraged the Company to convene stakeholders both before and after filing this Supplement.

The first of these stakeholder collaborative meetings took place on February 10, 2015 at the Commission's facility. Approximately 80 individuals attended the meeting, which included an overview of the resource planning process, a summary of modeling assumptions and scenarios, discussion of our analysis and criteria for selecting our Preferred Plan, and a preview of what would be included in this Supplement. Participants were encouraged to raise questions throughout the presentation, and the summary of questions and responses was provided to all attendees after the meeting. There was interest among attendees in ongoing stakeholder collaboration to address specific topics in greater detail. We have scheduled two workshops in April to cover Demand Side Management (Demand Response and Energy Efficiency) and Strategist Modeling. In the coming months we expect to hold additional workshops to address stakeholder interest in more in-depth discussion of customer cost impacts of the Preferred Plan, the impact of evolving environmental regulations on the future of our baseload coal-fired generating facilities, and the growing interest in distributed generation. We hope that this ongoing stakeholder engagement will proactively address concerns and gain support for our Plan, so that what is ultimately approved by the Commission reflects the results of stakeholder collaborative efforts that relied upon a robust engagement process.

---

[24] *Xcel Energy's Request for Planning Meeting and Dialogue in Support of e21 Initiative*, MPUC Docket No. E002/M-14-1055 (December 22, 2014).

X. CONCLUSION

We are pleased to present this Supplement to our 2016-2030 Upper Midwest Resource Plan to the Commission. We look forward to ongoing and productive dialogue with interested parties regarding the Company's vision for our resource future.

2016-2030 Upper Midwest Resource Plan – Supplement
Appendix – Strategist Modeling and Outputs Updates
Table of Contents

I. MODELING ASSUMPTIONS UPDATES

In addition to the Sherco assumptions we explained in the Supplement document, we provide here any additional details or updates to the Modeling assumptions from our January 2, 2015 Resource Plan filing (Initial Filing).

A. Non-Production Tax Credit Wind Prices

The Production Tax Credit (PTC) and non-PTC pricing developed and used for the 2016-2030 Resource Plan filed on January 2, 2015 reflects the pricing of bids received in response to the Company's 2013 Wind Request for Proposals (RFP). More specifically, the Company used the results of an extensive wind Power Purchase Agreement (PPA)/ownership bid evaluation process which focused on a large sample of PTC eligible wind project bid offers with in-service dates in the 2015-2017 timeframe. These offers provided actual wind project pricing representing a credible market price benchmark for PTC wind.

Using bid cost/price data, the Company calibrated its internally developed financial model for owned wind projects to reproduce PTC-adjusted prices comparable to the PPA bid prices. Although the Company's model is an ownership (i.e. revenue requirements) model, it also has the ability to convert the revenue requirement stream into an Economic Carrying Charge (ECC) equivalent, which is how wind is represented in the Strategist modeling. The modeled ECC was used for the price of PTC wind used in the scenarios that include an assumption for utilizing an extension of the wind PTC.

As background, the ECC is designed to measure the cost of a project or asset whose cost/price increases at the rate of inflation year of the asset's life or PPA term. Using an ECC provides the flexibility in developing a cost/pricing stream shorter than the full life of an asset; e.g. the term of a PPA. Bid pricing for both PPA and ownership offers were used to develop long-term PTC and non-PTC wind pricing assumptions for this Resource Plan.

The non-PTC pricing values were developed by simply removing the value of the PTC from the PTC wind values and developing the non-PTC wind ECC pricing stream. For all scenarios with wind additions in 2017 or later, it was assumed that the PTC was not extended. More specifically, the financial model was adjusted to not include the PTC benefit, but kept the other inputs (i.e. capital cost, Operations & Maintenance, capacity factor) constant. The ECC representation of the non-PTC wind was used for the Strategist wind cost inputs for all years post-2016, except in the specifically noted scenarios where a PTC extension is contemplated. The final ECC costs for PTC and non-PTC wind are included in Table 1 below.

Table 1: ECC PTC and Non-PTC Wind Price Assumptions

Year	PTC Wind	Non-PTC Wind	30% ITC Solar	10% ITC Solar
2014	25.71	45.46	75.00	95.00
2015	26.28	46.48	75.00	95.00
2016	26.87	47.52	75.00	95.00
2017	27.48	48.58	75.00	95.00
2018	28.09	49.67	75.00	95.00
2019	28.72	50.78	75.00	95.00
2020	29.36	51.92	75.00	95.00
2021	30.02	53.08	75.00	95.00
2022	30.69	54.27	75.00	95.00
2023	31.38	55.49	75.00	95.00
2024	32.08	56.73	75.00	95.00
2025	32.80	58.00	75.00	95.00
2026	33.54	59.30	75.00	95.00
2027	34.29	60.63	75.00	95.00
2028	35.06	61.99	75.00	95.00
2029	35.84	63.38	75.00	95.00
2030	36.65	64.80	75.00	95.00

B. CO_2 Modeling Assumptions

Per the Commission's current guidance, utilities need not apply the CO_2 externality value in any year in which they apply the CO_2 regulatory proxy cost value. However, in those years where the regulatory proxy cost value is *not* applied, we apply the Commission's currently-approved CO_2 *externality* value, therefore using the following input assumptions:

- In all Strategist runs using the base assumptions, we apply a CO_2 regulatory proxy cost value of $21.50/ton starting in 2019, the midpoint of the Commission's adopted range of $9/ton to $34/ton of CO_2. We apply the Commission's "high" CO_2 externality value of $4.46 in 2014 through 2018, and cease applying this value in 2019.

- As noted above, we only apply the Commission's "high CO_2 externality value. Therefore, we do not apply the Commission's "low" CO_2 externality value of $0.43 in any runs.

- In the sensitivity where the $21.50/ton regulatory cost midpoint is applied beginning in 2024, reflecting the possibility that CO_2 regulations may be delayed, we apply the Commission's "high" CO_2 externality value of $4.46 in 2014 through 2023, and cease applying this value in 2024.

- In the low CO_2 regulatory cost sensitivities, we apply $9/ton (the low end of the Commission-adopted range), beginning in 2019 and 2024. We apply the Commission's "high" CO_2 externality value of $4.46 in 2014 through 2018, and 2014 through 2023, respectively in these sensitivities.

- In the high CO_2 regulatory cost sensitivities, we apply $34/ton (the high end of the Commission-adopted range), beginning in 2019 and 2024. We apply the Commission's "high" CO_2 externality value of $4.46 in 2014 through 2018, and 2014 through 2023, respectively in these sensitivities.

- In the "$0 CO_2" sensitivity, reflecting the possibility that CO_2 remains unregulated, we apply the Commission's "high" CO_2 externality value of $4.46 in all years, 2014 through 2053.

- In the Federal social cost of carbon (SCC) sensitivity, we apply the 3.0 percent discount rate values from the November 2013 SCC revised Technical Support Document in all years, 2014 through 2053. This sensitivity includes no CO_2 regulatory proxy costs.

II. SCENARIOS AND SENSITIVITIES SUMMARY

A. Scenario Summary

The text below describes additional scenarios that are analyzed in the March 16 Supplement filing. All previous scenarios were run as they were described in the Initial Filing; however Sherco 2 is now the first unit retiring instead of Sherco 1. In addition, changes were made to the timing of units in runs 11 and 12.

- Scenario 11 (*Gas Boiler*) - Converts Sherco 1 to a gas boiler unit in 2025 and runs to 2040. Sherco 2 operates through 2030. In the IRP, Sherco 1 converted to the gas boiler in 2026.

- Scenario 12 (*CC Repowering*) - Converts Sherco 1 to a 4x1 natural gas combined cycle facility by repowering the steam turbine generator. The plant is brought offline September 30, 2023 and is back online in March, 2025. Sherco 2 retires year end 2025. In the IRP, Sherco 1 was brought offline year end 2025 and was back online in early 2027.

B. Additional Scenarios Analyzed

1. *Preferred Plan Variants*

- Scenario 10D (Preferred Plan with Sherco 2 Retirement) - Has the same renewables as the Preferred Plan (Scenario 10), but Sherco 2 retires May 31, 2021 to ensure capacity eligibility for the entire 2020/2021 MISO Planning Year.

- Scenario 10E (Preferred Plan with both Sherco Retirements) - Has the same renewables as the Preferred Plan (Scenario 10), but Sherco 1 and 2 retire May 31, 2021 to ensure their capacity eligibility for the entire 2020/2021 MISO Planning Year.

- Scenario 10F (Preferred Plan with both Sherco Retirements) - Has the same renewables as the Preferred Plan (Scenario 10), but Sherco 2 retires May 31, 2021, and Sherco 1 retires May 31, 2024 to ensure their capacity value through the then-current MISO planning year.

- Scenario 10G (Preferred Plan with both Sherco Retirements) - Has the same renewables as the Preferred Plan (Scenario 10) but Sherco 1 and 2 retire May 31, 2021 to ensure their capacity eligibility for the entire 2020/2021 MISO Planning Year.

2. *Additional Sherco Scenarios*

- Scenario 16 (*CC Replacement*) - Sherco 2 retires May 31, 2021 to ensure capacity eligibility for the entire 2020/2021 MISO Planning Year and is replaced with a 2x1 natural gas combined cycle unit in 2025.

- Scenario 17 (*CT Replacement*) - Sherco 2 retires May 31, 2021 to ensure capacity eligibility for the entire 2020/2021 MISO Planning Year and is replaced with three natural gas combustion turbines units; one in 2021 and two in 2024.

- Scenario 18A (*50 percent Renewable Replacement, Wind*) - Sherco 2 retires May 31, 2021 to ensure capacity eligibility for the entire 2020/2021 MISO Planning Year and is replaced with three natural gas combustion turbine units and 600 MW of wind generation projects in 2021.

- Scenario 18B (*50 percent Renewable Replacement, Wind, Solar*)- Sherco 2 retires May 31, 2021 to ensure capacity eligibility for the entire 2020/2021 MISO Planning Year and is replaced with two natural gas combustion turbine units, 400 MW of wind generation projects, and 450 MW of utility scale solar generation projects in 2021.

- Scenario 18C (*50 percent Renewable Replacement, Wind, Solar, DSM*) - Sherco 2 retires May 31, 2021 to ensure capacity eligibility for the entire 2020/2021 MISO Planning Year and is replaced with two natural gas combustion turbine units, 400 MW of wind generation projects, and 250 MW of utility scale solar generation projects in 2021DSM is added at the 1.7 percent scenario level.

- Scenario 19A (*75 percent Renewable Replacement, Wind*) - Sherco 2 retires May 31, 2021 to ensure capacity eligibility for the entire 2020/2021 MISO Planning Year and is replaced with three natural gas combustion turbine units and 1,000 MW of wind generation projects in 2021.

- Scenario 19B (*75 percent Renewable Replacement, Wind, Solar*)- Sherco 2 retires May 31, 2021 to ensure capacity eligibility for the entire 2020/2021 MISO Planning Year and is replaced with two natural gas combustion turbine units, 600 MW of wind generation projects, and 700 MW of utility scale solar generation projects in 2021.

- Scenario 19C (*75 percent Renewable Replacement, Wind, Solar, DSM*) - Sherco 2 retires May 31, 2021 to ensure capacity eligibility for the entire 2020/2021 MISO Planning Year and is replaced with one natural gas combustion turbine unit, 600 MW of wind generation projects, and 500 MW of utility scale solar generation projects in 2021. DSM is added at the 1.7 percent scenario level.

- Scenario 20 (*CC Replacement*) - Sherco 1 and 2 retire May 31, 2021 to ensure their capacity eligibility for the entire 2020/2021 MISO Planning Year and are replaced with three natural gas combustion turbine units in 2021 and one 2x1 natural gas combined cycle unit in 2025.

- Scenario 21 (*CT Replacement*) - Sherco 1 and 2 retire May 31, 2021 to ensure their capacity eligibility for the entire 2020/2021 MISO Planning Year and are replaced with three natural gas combustion turbine units in 2021 and three natural gas combustion turbine units in 2025.

- Scenario 22A (*50 percent Renewable Replacement, Wind*) - Sherco 1 and 2 retire May 31, 2021 to ensure their capacity eligibility for the entire 2020/2021 MISO Planning Year and are replaced with six natural gas combustion turbine units and 1,200 MW of wind generation projects in 2021.

- Scenario 22B (*50 percent Renewable Replacement, Wind, Solar*)- Sherco 1 and 2 retire May 31, 2021 to ensure their capacity eligibility for the entire 2020/2021 MISO Planning Year and are replaced with four natural gas combustion turbine units, 800 MW of wind generation projects, and 800 MW of utility scale solar generation projects in 2021.

- Scenario 22C (*50 percent Renewable Replacement, Wind, Solar, DSM*) - Sherco 1 and 2 retire May 31, 2021 to ensure their capacity eligibility for the entire 2020/2021 MISO Planning Year and are replaced with four combustion turbine units, 800 MW wind, and 600 MW of utility scale solar projects in 2021. DSM is added at the 1.7 percent scenario level.

- Scenario 23A (*75 percent Renewable Replacement, Wind*) - Sherco 1 and 2 retire May 31, 2021 to ensure their capacity eligibility for the entire 2020/2021 MISO Planning Year and are replaced with five natural gas combustion turbine units and 1,800 MW of wind generation projects in 2021.

- Scenario 23B (*75 percent Renewable Replacement, Wind, Solar*)- Sherco 1 and 2 retire May 31, 2021 to ensure their capacity eligibility for the entire 2020/2021 MISO Planning Year and are replaced with three natural gas combustion turbine units, 1,200 MW of wind generation projects, and 1,250 MW of utility scale solar generation projects in 2021.

- Scenario 23C (*75 percent Renewable Replacement, Wind, Solar, DSM*) - Sherco 1 and 2 retire May 31, 2021 to ensure their capacity eligibility for the entire 2020/2021 MISO Planning Year and are replaced with three combustion turbine units, 1,200 MW wind, 1,000 MW of utility scale solar projects in 2021. DSM is added at the 1.7 percent scenario level.

- Scenario 24 (*CC Replacement*) - Sherco 2 retires May 31, 2021 and Sherco 1 retires May 31, 2024 to ensure their capacity value through the then-current MISO planning year and are replaced with one 2x1 natural gas combined cycle unit in 2024, one natural gas combustion turbine unit in 2021, and two natural gas combustion turbine units in 2024.

- Scenario 25 (*CT Replacement*) - Sherco 2 retires May 31, 2021 and Sherco 1 retires May 31, 2024 to ensure their capacity value through the then-current MISO planning year and are replaced with one natural gas combustion turbine unit in 2021, and five natural gas combustion turbine units in 2024.

- Scenario 26A (*50 percent Renewable Replacement, Wind*) - Sherco 2 retires May 31, 2021 and Sherco 1 retires May 31, 2024 to ensure their capacity value through the then-current MISO planning year and are replaced with three natural gas combustion turbine units and 600 MW of wind generation projects in 2021 and three natural gas combustion turbine units and 600 MW of wind generation projects in 2024.

- Scenario 26B (*50 percent Renewable Replacement, Wind, Solar*) - Sherco 2 retires May 31, 2021 and Sherco 1 retires May 31, 2024 to ensure their capacity value through the then-current MISO planning year and are replaced with two natural gas combustion turbine units, 400 MW of wind generation projects, and 400 MW of utility scale solar generation projects in 2021 and two natural gas combustion turbine units, 400 MW of wind generation projects, and 400 MW of utility scale solar generation projects in 2024.

- Scenario 26C (*50 percent Renewable Replacement, Wind, Solar, DSM*) - Sherco 2 retires May 31, 2021 and Sherco 1 retires May 31, 2024 to ensure their capacity value through the then-current MISO planning year and are replaced with two combustion turbine units, 400 MW wind, and 300 MW of utility scale solar projects in 2021 and two combustion turbine units, 400 MW wind, and 300 MW of utility scale solar projects in 2024. DSM is added at the 1.7 percent scenario level.

- Scenario 27A (*75 percent Renewable Replacement, Wind*) - Sherco 2 retires May 31, 2021 and Sherco 1 retires May 31, 2024 to ensure their capacity value through the then-current MISO planning year and are replaced with three natural gas combustion turbine units and 1,000 MW of wind generation projects in 2021 and two natural gas combustion turbine units and 800 MW of wind generation projects in 2024.

- Scenario 27B (*75 percent Renewable Replacement, Wind, Solar*) - Sherco 2 retires May 312021 and Sherco 1 retires May 31, 2024 to ensure their capacity value through the then-current MISO planning year and are replaced with two natural gas combustion turbine units, 600 MW of wind generation projects, and 650 MW of utility scale solar generation projects in 2021 and one natural gas combustion turbine unit, 600 MW of wind generation projects, and 600 MW of utility scale solar generation projects in 2024.

- Scenario 27C (*75 percent Renewable Replacement, Wind, Solar, DSM*) - Sherco 2 retires May 31 2021 and Sherco 1 retires May 31 2024 to ensure their capacity value through the then-current MISO planning year and are replaced with two combustion turbine units, 600 MW wind, and 500 MW of utility scale solar projects in 2021 and one combustion turbine unit, 600 MW wind, and 500 MW of utility scale solar projects in 2024. DSM is added at the 1.7 percent scenario level.

A full summary of the scenarios included in this Supplement is included below as Table 2, which is an updated version of Table 19 in Appendix J of the Initial Filing.

Table 2: 2016-2030 Resource Plan Supplement Modeling Scenarios Summary

PRIMARY SHERCO / CARBON / RENEWABLE ALTERNATIVES		Strategist Output Code
Continued Operation (Run Both Units to 2030)		
	Reference Case - No SCR's and both units retire 2030	1
	Add SCR's to both units (Spring 2024 and 2025) and retire in 2030	1B
Retire 1 SH Unit YE 2025 (Continued Operation of Remaining Unit Through YE2030)		
	Replace: CC	2
	Replace: CT	3
Force 50% renewables:		
	Replace 50% Renew: CT + Wind	4A
	Replace 50% Renew: CT + Wind + Solar	4B
	Replace 50% Renew: CT + Wind + Solar + DSM (High Scenario)	4C
Force 75% renewables:		
	Replace 75% Renew: CT + Wind	5A
	Replace 75% Renew: CT + Wind + Solar	5B
	Replace 75% Renew: CT + Wind + Solar + DSM (High Scenario)	5C
Retire Both Units YE 2025		
	Replace: CC	6
	Replace: CT	7
Force 50% renewables:		
	Replace 50% Renew: CT + Wind	8A
	Replace 50% Renew: CT + Wind + Solar	8B
	Replace 50% Renew: CT + Wind + Solar + DSM (High Scenario)	8C
Force 75% renewables:		
	Replace 75% Renew: CT + Wind	9A
	Replace 75% Renew: CT + Wind + Solar	9B
	Replace 75% Renew: CT + Wind + Solar + DSM (High Scenario)	9C
Early Retire 1 SH Unit YE 2020 (Continued Operation of Remaining Unit Through YE2030)		
	Replace: CC	16
	Replace: CT	17
Force 50% renewables:		
	Replace 50% Renew: CT + Wind	18A
	Replace 50% Renew: CT + Wind + Solar	18B
	Replace 50% Renew: CT + Wind + Solar + DSM (High Scenario)	18C
Force 75% renewables:		
	Replace 75% Renew: CT + Wind	19A
	Replace 75% Renew: CT + Wind + Solar	19B
	Replace 75% Renew: CT + Wind + Solar + DSM (High Scenario)	19C
Early Retire Both Units YE 2020		
	Replace: CC	20
	Replace: CT	21

PRIMARY SHERCO / CARBON / RENEWABLE ALTERNATIVES		Strategist Output Code
Force 50% renewables:		
	Replace 50% Renew: CT + Wind	22A
	Replace 50% Renew: CT + Wind + Solar	22 B
	Replace 50% Renew: CT + Wind + Solar + DSM (High Scenario)	22C
Force 75% renewables:		
	Replace 75% Renew: CT + Wind	23A
	Replace 75% Renew: CT + Wind + Solar	23B
	Replace 75% Renew: CT + Wind + Solar + DSM (High Scenario)	23C
Phased Early Retire Both Units (1 SH Unit YE 2020, Remaining Unit YE2023)		
	Replace: CC	24
	Replace: CT	25
Force 50% renewables:		
	Replace 50% Renew: CT + Wind	26A
	Replace 50% Renew: CT + Wind + Solar	26B
	Replace 50% Renew: CT + Wind + Solar + DSM (High Scenario)	26C
Force 75% renewables:		
	Replace 75% Renew: CT + Wind	27A
	Replace 75% Renew: CT + Wind + Solar	27B
	Replace 75% Renew: CT + Wind + Solar + DSM (High Scenario)	27C
Preferred Plan		
	Preferred Plan	10
	Preferred Plan with PTC Extension	10A
	Preferred Plan with Retire 1 SH unit YE 2025 (Continued Operation of Remaining Unit Through YE2030)	10B
	Preferred Plan with Retire 1 SH unit YE 2025 and PTC Extension	10C
	Preferred Plan with Early Retire 1 SH Unit YE 2020 (Continued Operation of Remaining Unit Through YE2030)	10D
	Preferred Plan with Early Retire Both Units YE2020	10E
	Preferred Plan with Phased Early Retire Both Units (1 SH Unit YE 2020, Remaining Unit YE2023)	10F
	Preferred Plan with Retire Both Units YE2025	10G
Convert 1 SH Unit to Gas Boiler		
	Convert 1 SH unit to Gas. Continued Operation of Remaining Unit Through YE 2030. Gas Boiler retires YE 2040	11
Repower 1 SH Unit STG as CC, Retire Remaining Unit YE 2025		
	Repower 1 SH unit to 4x1 CC. Remaining Unit Retires YE 2025	12
North Dakota Plan		
	No additional renewables beyond currently committed 750MW wind	15

PRIMARY SHERCO / CARBON / RENEWABLE ALTERNATIVES		Strategist Output Code
DR alternative portfolios		13 (various)
	No DR (used for cost effectiveness)	A-G
	Low DR capacity	H-N
	Med DR capacity	O-U
	High DR capacity	V-AB
	Base DR capacity	AC-AI
EE alternative portfolios		14 (various)
	No EE Achievement (used for cost effectiveness)	A-G
	Low EE Achievement	H-N; AC-AI
	Med EE Achievement	O-U; AJ-AP
	High EE Achievement	V-AB;AQ-AW

C. Sensitivity Updates Summary

To determine how changes in our assumptions impact the costs or characteristics of different Resource Plans, we examine our plans under a number of sensitivities. If a plan is extremely sensitive to changes in assumptions, it is not a robust course of action for the Company to pursue. Instead, we conceivably could propose an expansion plan that is less sensitive to assumption changes, but slightly more costly than the least-cost scenario under starting assumptions. For this Supplement, we used all the same sensitivity cases that were used in the Initial Filing, with two exceptions. Those sensitivities are summarized on pages 38-39 of Appendix J of our Initial Filing.

The **Customer Impact** sensitivity was performed in the Initial filing, but the description of the sensitivity was not included in the Resource Plan document. The **Do Not Maintain CAPCON Length** sensitivity is a new sensitivity performed in the March 16 Supplement runs, and is referred to as the Traditional view in the Supplement document. Descriptions of both sensitivities are below:

- *Customer Impact.* To quantify the impact to customer costs (i.e. rates), no capacity credit was given for excess capacity, and all carbon and externality costs were removed.

- *Do Not Maintain CAPCON Length/Traditional.* To reflect the impact of not preserving the capacity length gained with the addition of the CAPCON resources through 2024, a sensitivity was performed where the capacity length was not preserved.

Table 3 below gives a summary of all the Modeling Sensitivities included in this Supplemental filing.

Table 3: 2016-2030 Resource Plan Supplement Modeling Sensitivity Summary

Base CO2 (Mid) Costs	**Strategist Output Code**
Low Load	A
High Load	B
Low Gas Prices	C
High Gas Prices	D
Low Coal Prices	E
High Coal Prices	F
Low Wind Cost	G
High Wind Cost	H
Low Solar Cost	I
High Solar Cost	J
Low Wind Cost, Low Solar Cost	V
High SHC Costs (FOM, Ongoing Capital), +10%	Q
Do Not Maintain CAPCON Length	R
Markets On	S
Remove ND Load	X
Zero CO2 Costs	
No Regulated CO2 (Contains Externality CO2)	K
ND Assumptions (No Extern, No CO2 Costs)	T
"Customer impact" (No Cap Credit, No Extern, No CO2 Costs)	U
Low Wind Prices, No Regulated CO2 Costs (Contains Externality CO2)	W
Low Load, No Extern, No CO2 Costs	AT
High Load, No Extern, No CO2 Costs	BT
Low Gas Prices, No Extern, No CO2 Costs	CT
High Gas Prices, No Extern, No CO2 Costs	DT
Low Wind Cost, No Extern, No CO2 Costs	GT
High Wind Cost, No Extern, No CO2 Costs	HT
Low Solar Cost, No Extern, No CO2 Costs	IT
High Solar Cost, No Extern, No CO2 Costs	JT
Do Not Maintain CAPCON Length, No Extern, No CO2 Costs	RT
Do Not Maintain CAPCON Length, No Cap Credit, No Extern, No CO2 Costs	RU
Other CO2 Sensitivities	
CO2 $9, Start 2019	L
CO2 $34, Start 2019	M
CO2 $9, Start 2024	N
CO2 $34, Start 2024	O
CO2 at Federal SCC 3%	P

III. DISTRIBUTED SOLAR RESOURCE UPDATES

It was assumed that distributed solar, including the Company's Solar*Rewards program and Made in Minnesota will be added through 2020 at a consistent rate that, when combined with the 187 MW of utility-scale solar, will enable the Company to meet the state of Minnesota Solar Energy Standards target of 1.5 percent of non-excluded Minnesota sales by 2020 as well as the small solar carve-out. The assumptions for these programs are consistent with our Initial Filing.

Due to the large response to the Company's Solar*Rewards Community program, we have accelerated the additions of community solar gardens by 200 MW by 2020. This means we have increased our previous forecast for community solar gardens from approximately 32 MW by 2020 in our Initial Filing to approximately 232 MW of by 2020 in this Supplement.

For our Reference Case assumptions, we are assuming that community solar gardens adjusts to 5 MW per year after 2020, and other additions of small solar remain constant following 2020. The schedule of small additions is shown below in Table 4, which is an updated version of Table 17 in Appendix J from our January 2 filing.

Table 4: Distributed Solar Additions (AC MW), Reference Case

Year	Solar* Rewards	Made in MN Small	Made in MN Large	Solar Gardens
2014	3.9	1.2	3.7	0.0
2015	3.9	1.2	3.7	30.0
2016	3.9	1.2	3.7	33.0
2017	3.9	1.2	3.7	36.3
2018	3.9	1.2	3.7	39.9
2019	3.9	1.2	3.7	43.9
2020	3.9	1.2	3.7	49.3
2021	3.9	1.2	3.7	5.0
2022	3.9	1.2	3.7	5.0
2023	3.9	1.2	3.7	5.0
2024	3.9	1.2	3.7	5.0
2025	3.9	1.2	3.7	5.0
2026	3.9	1.2	3.7	5.0
2027	3.9	1.2	3.7	5.0
2028	3.9	1.2	3.7	5.0
2029	3.9	1.2	3.7	5.0
2030	3.9	1.2	3.7	5.0
Total	**66.5**	**20.3**	**62.3**	**282.5**

For the Preferred Plan, the Company is proposing a 20 percent annual growth rate for distributed solar beyond 2020, predicting continued sustainable growth in distributed solar past 2020, at a rate that increases annual additions by 20 percent year over year.

For this Supplemental filing, the Company has adjusted the Solar Community Gardens program upwards in the same manner as the base assumption (additional 200 MW by 2020), while keeping the remainder of the forecast consistent with the Initial Filing. Additionally, for consistency, we are showing the Made in Minnesota program continuing past 2020 at the same rate as the base assumptions, with the Solar*Rewards amounts being adjusted downwards to reflect the difference (keeping the total non-Solar Gardens amounts the same as the January 2, 2015 filing).

The resulting schedule of additions for the Preferred Plan is shown below in Table 5, which is an updated version of Table 18 in Appendix J of the January 2 filing.

Table 5: Distributed Solar Additions (AC MW), Preferred Plan

Year	Solar* Rewards	Made in MN Small	Made in MN Large	Solar Gardens
2014	3.9	1.2	3.7	0.0
2015	3.9	1.2	3.7	30.0
2016	3.9	1.2	3.7	33.0
2017	3.9	1.2	3.7	36.3
2018	3.9	1.2	3.7	39.9
2019	3.9	1.2	3.7	43.9
2020	3.9	1.2	3.7	49.3
2021	5.7	1.2	3.7	6.0
2022	7.8	1.2	3.7	7.2
2023	10.3	1.2	3.7	8.6
2024	13.3	1.2	3.7	10.4
2025	17.0	1.2	3.7	12.4
2026	21.3	1.2	3.7	14.9
2027	26.6	1.2	3.7	17.9
2028	32.8	1.2	3.7	21.5
2029	40.4	1.2	3.7	25.8
2030	49.4	1.2	3.7	31.0
Total	**252.0**	**20.3**	**62.3**	**388.2**

IV. SCENARIO OUTCOMES

An updated summary of the Strategist model's output Net Present Value Revenue Requirement (PVRR)/Net Present Value of Societal Costs (PVSC) for the various scenarios and sensitivities is shown below in Tables 6 and 7. These are updates of Tables 21 and 22 in Appendix J of the Initial Filing.

Table 6: PVSC/PVRR Total ($M) for all Scenarios/Sensitivities A-Q

Scenario	Number	A BASE	B LOW LOAD	C HIGH LOAD	D LOW GAS PRICE	E HIGH GAS PRICE	F LOW COAL PRICE	G HIGH COAL PRICE	H LOW WIND COST	I HIGH WIND COST	J LOW SOLAR COST	K HIGH SOLAR COST	L ZERO CO2	M LOW CO2	N HIGH CO2	O LATE LOW CO2	P LATE HIGH CO2	Q SOCIAL COST OF CARBON	HIGH SHERCO COSTS
Reference Case*	1	$52,464	$49,172	$56,109	$49,092	$57,115	$51,918	$53,059	$52,333	$52,594	$52,464	$52,464	$47,629	$48,823	$55,924	$48,362	$53,277	$66,350	$52,548
Reference Case with SCRs*	1B	$52,740	$49,448	$56,386	$49,367	$57,391	$52,195	$53,335	$52,609	$52,871	$52,740	$52,740	$47,905	$49,100	$56,198	$48,638	$53,551	$66,627	$52,826
Retire 1 Unit 2025 Replace with 2x1 CC*	2	$52,593	$49,299	$56,234	$49,140	$57,343	$52,102	$53,123	$52,462	$52,724	$52,593	$52,593	$47,886	$49,050	$55,957	$48,594	$53,327	$66,230	$52,667
Retire 1 Unit 2025 Replace with CTs*	3	$52,595	$49,342	$56,243	$49,146	$57,352	$52,098	$53,137	$52,465	$52,726	$52,595	$52,595	$47,871	$49,037	$55,986	$48,581	$53,351	$66,248	$52,670
Retire 1 Unit 2025 Replace with 50% Renewables - Wind*	4A	$52,557	$49,300	$56,207	$49,186	$57,207	$52,069	$53,087	$52,371	$52,743	$52,557	$52,557	$47,927	$49,071	$55,873	$48,618	$53,254	$66,021	$52,632
Retire 1 Unit 2025 Replace with 50% Renewables - Wind & Solar*	4B	$52,468	$49,209	$56,127	$49,109	$57,096	$51,978	$52,999	$52,315	$52,621	$52,421	$52,515	$47,845	$48,988	$55,775	$48,535	$53,158	$65,909	$52,542
Retire 1 Unit 2025 Replace with 50% Renewables - Wind, Solar, & DSM*	4C	$52,806	$49,580	$56,428	$49,435	$57,461	$52,316	$53,339	$52,654	$52,959	$52,780	$52,832	$48,185	$49,326	$56,118	$48,878	$53,523	$66,246	$52,881
Retire 1 Unit 2025 Replace with 75% Renewables - Wind*	5A	$52,532	$49,288	$56,180	$49,276	$57,023	$52,049	$53,057	$52,279	$52,785	$52,532	$52,532	$47,997	$49,117	$55,780	$48,668	$53,175	$65,774	$52,606
Retire 1 Unit 2025 Replace with 75% Renewables - Wind & Solar*	5B	$52,395	$49,139	$56,036	$49,133	$56,889	$51,908	$52,922	$52,209	$52,581	$52,321	$52,468	$47,850	$48,972	$55,646	$48,524	$53,041	$65,650	$52,469
Retire 1 Unit 2025 Replace with 75% Renewables - Wind, Solar, & DSM*	5C	$52,727	$49,516	$56,354	$49,452	$57,241	$52,243	$53,251	$52,541	$52,913	$52,675	$52,780	$48,194	$49,314	$55,967	$48,869	$53,388	$65,968	$52,802
Retire 2 Units 2025 Replace with 2x1 CCs*	6	$52,744	$49,455	$56,391	$49,209	$57,613	$52,312	$53,211	$52,613	$52,875	$52,744	$52,744	$48,177	$49,305	$56,026	$48,855	$53,411	$66,089	$52,810
Retire 2 Units 2025 Replace with CTs*	7	$52,808	$49,599	$56,501	$49,267	$57,686	$52,374	$53,278	$52,677	$52,939	$52,808	$52,808	$48,228	$49,359	$56,104	$48,909	$53,485	$66,170	$52,875
Retire 2 Units 2025 Replace with 50% Renewables - Wind*	8A	$52,708	$49,449	$56,339	$49,392	$57,311	$52,274	$53,182	$52,422	$52,994	$52,708	$52,708	$48,294	$49,382	$55,886	$48,939	$53,292	$65,692	$52,774
Retire 2 Units 2025 Replace with 50% Renewables - Wind & Solar*	8B	$52,532	$49,273	$56,205	$49,235	$57,101	$52,096	$53,007	$52,312	$52,751	$52,448	$52,616	$48,130	$49,215	$55,697	$48,773	$53,107	$65,470	$52,598
Retire 2 Units 2025 Replace with 50% Renewables - Wind, Solar, & DSM*	8C	$52,870	$49,644	$56,462	$49,559	$57,462	$52,435	$53,343	$52,650	$53,089	$52,806	$52,933	$48,476	$49,559	$56,030	$49,120	$53,464	$65,800	$52,936
Retire 2 Units 2025 Replace with 75% Renewables - Wind*	9A	$52,681	$49,408	$56,288	$49,545	$57,030	$52,253	$53,146	$52,294	$53,067	$52,681	$52,681	$48,412	$49,463	$55,748	$49,026	$53,178	$65,340	$52,747
Retire 2 Units 2025 Replace with 75% Renewables - Wind & Solar*	9B	$52,385	$49,152	$56,038	$49,281	$56,678	$51,956	$52,850	$52,099	$52,671	$52,254	$52,516	$48,140	$49,187	$55,428	$48,751	$52,864	$64,960	$52,451
Retire 2 Units 2025 Replace with 75% Renewables - Wind, Solar, & DSM*	9C	$52,732	$49,503	$56,328	$49,608	$57,059	$52,305	$53,197	$52,446	$53,018	$52,627	$52,837	$48,490	$49,536	$55,776	$49,103	$53,235	$65,313	$52,799
Preferred Plan*	10	$52,119	$48,898	$55,708	$49,261	$56,099	$51,605	$52,687	$51,784	$52,454	$51,983	$52,256	$47,791	$48,855	$55,230	$48,422	$52,699	$64,899	$52,204
Preferred Plan with PTC*	10A	$51,298	$48,087	$54,862	$48,398	$55,347	$50,791	$51,859	$51,164	$51,431	$51,161	$51,434	$47,016	$48,065	$54,387	$47,652	$51,964	$63,946	$51,382
Preferred Plan with Retire 1 Unit 2025*	10B	$52,223	$48,989	$55,819	$49,293	$56,276	$51,754	$52,730	$51,888	$52,558	$52,087	$52,360	$48,000	$49,040	$55,240	$48,611	$52,727	$64,796	$52,298
Preferred Plan with Retire 1 Unit 2025 & PTC*	10C	$51,402	$48,180	$54,973	$48,430	$55,524	$50,940	$51,901	$51,268	$51,535	$51,265	$51,538	$47,224	$48,250	$54,397	$47,841	$51,993	$63,843	$51,476
Preferred Plan with Retire 1 Unit 2020**	10D	$52,258	$48,975	$55,901	$49,278	$56,382	$51,815	$52,743	$51,923	$52,593	$52,121	$52,394	$48,127	$49,144	$55,229	$48,733	$52,829	$64,645	$52,318
Preferred Plan with Retire 2 Units 2020**	10E	$52,488	$49,179	$56,150	$49,358	$56,788	$52,142	$52,860	$52,153	$52,823	$52,351	$52,624	$48,629	$49,582	$55,267	$49,200	$53,041	$64,361	$52,523
Preferred Plan with Retire 1 Unit 2020, 1 Unit 2023**	10F	$52,429	$49,133	$56,074	$49,340	$56,680	$52,061	$52,823	$52,093	$52,764	$52,292	$52,565	$48,487	$49,460	$55,256	$49,057	$52,884	$64,448	$52,473
Preferred Plan with Retire 2 Units 2025*	10G	$52,435	$49,120	$55,962	$49,447	$56,536	$52,030	$52,868	$52,100	$52,771	$52,299	$52,572	$48,374	$49,378	$55,330	$48,956	$52,841	$64,681	$52,502
Convert 1 Unit to Gas Boiler*	11	$52,491	$49,200	$56,142	$49,020	$57,262	$52,013	$53,006	$52,360	$52,622	$52,491	$52,491	$47,815	$48,971	$55,834	$48,517	$53,208	$66,070	$52,563
Convert 2 Units to 4x1 CC*	12	$52,349	$49,054	$56,060	$48,788	$57,214	$51,952	$52,774	$52,218	$52,480	$52,349	$52,349	$47,921	$49,022	$55,512	$48,578	$52,929	$65,464	$52,416
North Dakota Plan*	15	$52,723	$49,405	$56,381	$49,104	$57,732	$52,157	$53,346	$52,723	$52,723	$52,723	$52,723	$47,592	$48,859	$56,409	$48,370	$53,608	$67,237	$52,808
Retire 1 Unit 2020 Replace with 2x1 CC**	16	$52,680	$49,326	$56,336	$49,165	$57,498	$52,224	$53,170	$52,549	$52,811	$52,680	$52,680	$48,097	$49,231	$55,957	$48,794	$53,453	$66,104	$52,740
Retire 1 Unit 2020 Replace with CTs**	17	$52,676	$49,318	$56,335	$49,163	$57,494	$52,219	$53,168	$52,545	$52,807	$52,676	$52,676	$48,088	$49,223	$55,960	$48,787	$53,454	$66,102	$52,736
Retire 1 Unit 2020 Replace with 50% Renewables - Wind**	18A	$52,688	$49,430	$56,329	$49,249	$57,433	$52,238	$53,176	$52,479	$52,898	$52,688	$52,688	$48,231	$49,331	$55,891	$48,910	$53,470	$65,902	$52,748
Retire 1 Unit 2020 Replace with 50% Renewables - Wind & Solar**	18B	$52,635	$49,372	$56,283	$49,209	$57,357	$52,183	$53,123	$52,467	$52,803	$52,570	$52,700	$48,185	$49,284	$55,826	$48,863	$53,411	$65,821	$52,695
Retire 1 Unit 2020 Replace with 50% Renewables - Wind, Solar, & DSM**	18C	$52,935	$49,690	$56,559	$49,498	$57,679	$52,482	$53,427	$52,766	$53,103	$52,899	$52,971	$48,477	$49,578	$56,138	$49,158	$53,732	$66,132	$52,995
Retire 1 Unit 2020 Replace with 75% Renewables - Wind**	19A	$52,712	$49,477	$56,347	$49,382	$57,315	$52,271	$53,192	$52,420	$53,004	$52,712	$52,712	$48,385	$49,451	$55,826	$49,043	$53,467	$65,688	$52,772
Retire 1 Unit 2020 Replace with 75% Renewables - Wind & Solar**	19B	$52,637	$49,384	$56,258	$49,304	$57,239	$52,191	$53,120	$52,428	$52,846	$52,536	$52,738	$48,292	$49,365	$55,756	$48,954	$53,391	$65,621	$52,697
Retire 1 Unit 2020 Replace with 75% Renewables - Wind, Solar, & DSM**	19C	$52,898	$49,669	$56,531	$49,554	$57,514	$52,453	$53,379	$52,688	$53,107	$52,826	$52,970	$48,555	$49,627	$56,013	$49,217	$53,660	$65,880	$52,958
Retire 2 Units 2020 Replace with 2x1 CCs**	20	$52,931	$49,563	$56,611	$49,259	$57,957	$52,575	$53,312	$52,800	$53,061	$52,931	$52,931	$48,634	$49,697	$56,035	$49,291	$53,704	$65,800	$52,965
Retire 2 Units 2020 Replace with CTs**	21	$52,944	$49,726	$56,683	$49,272	$57,974	$52,589	$53,327	$52,814	$53,075	$52,944	$52,944	$48,643	$49,707	$56,054	$49,302	$53,722	$65,820	$52,979
Retire 2 Units 2020 Replace with 50% Renewables - Wind**	22A	$52,943	$49,674	$56,563	$49,525	$57,649	$52,602	$53,308	$52,610	$53,276	$52,943	$52,943	$48,948	$49,933	$55,826	$49,558	$53,655	$65,288	$52,978
Retire 2 Units 2020 Replace with 50% Renewables - Wind & Solar**	22B	$52,818	$49,535	$56,447	$49,424	$57,474	$52,475	$53,183	$52,567	$53,069	$52,702	$52,934	$48,841	$49,824	$55,679	$49,449	$53,517	$65,087	$52,853
Retire 2 Units 2020 Replace with 50% Renewables - Wind, Solar, & DSM**	22C	$53,113	$49,856	$56,733	$49,694	$57,816	$52,771	$53,479	$52,863	$53,364	$53,026	$53,200	$49,123	$50,109	$55,985	$49,735	$53,832	$65,423	$53,148
Retire 2 Units 2020 Replace with 75% Renewables - Wind**	23A	$53,000	$49,740	$56,603	$49,733	$57,534	$52,656	$53,374	$52,543	$53,456	$53,000	$53,000	$49,134	$50,081	$55,805	$49,721	$53,701	$65,112	$53,035
Retire 2 Units 2020 Replace with 75% Renewables - Wind & Solar**	23B	$52,801	$49,545	$56,410	$49,564	$57,287	$52,456	$53,175	$52,469	$53,134	$52,621	$52,982	$48,962	$49,906	$55,575	$49,546	$53,487	$64,812	$52,836
Retire 2 Units 2020 Replace with 75% Renewables - Wind, Solar, & DSM**	23C	$53,095	$49,864	$56,690	$49,838	$57,609	$52,748	$53,470	$52,762	$53,428	$52,950	$53,239	$49,242	$50,189	$55,880	$49,830	$53,798	$65,129	$53,129
Retire 1 Unit 2020, 1 Unit 2023 Replace with 2x1 CC**	24	$52,857	$49,506	$56,526	$49,229	$57,834	$52,480	$53,264	$52,727	$52,988	$52,857	$52,857	$48,471	$49,556	$56,016	$49,128	$53,533	$65,881	$52,902
Retire 1 Unit 2020, 1 Unit 2023 Replace with CTs**	25	$52,859	$49,545	$56,532	$49,230	$57,836	$52,480	$53,266	$52,728	$52,989	$52,859	$52,859	$48,468	$49,554	$56,023	$49,126	$53,538	$65,886	$52,903
Retire 1 Unit 2020, 1 Unit 2023 Replace with 50% Renewables - Wind**	26A	$52,843	$49,578	$56,463	$49,469	$57,489	$52,479	$53,233	$52,525	$53,161	$52,843	$52,843	$48,736	$49,750	$55,798	$49,344	$53,425	$65,340	$52,888
Retire 1 Unit 2020, 1 Unit 2023 Replace with 50% Renewables - Wind & Solar**	26B	$52,707	$49,431	$56,340	$49,341	$57,334	$52,341	$53,097	$52,466	$52,948	$52,601	$52,812	$48,605	$49,619	$55,651	$49,213	$53,281	$65,174	$52,751
Retire 1 Unit 2020, 1 Unit 2023 Replace with 50% Renewables - Wind, Solar, & DSM**	26C	$53,019	$49,770	$56,637	$49,643	$57,665	$52,654	$53,410	$52,779	$53,260	$52,940	$53,099	$48,919	$49,933	$55,963	$49,529	$53,611	$65,486	$53,064
Retire 1 Unit 2020, 1 Unit 2023 Replace with 75% Renewables - Wind**	27A	$52,908	$49,646	$56,490	$49,683	$57,382	$52,541	$53,306	$52,471	$53,345	$52,908	$52,908	$48,927	$49,904	$55,788	$49,510	$53,473	$65,167	$52,952
Retire 1 Unit 2020, 1 Unit 2023 Replace with 75% Renewables - Wind & Solar**	27B	$52,666	$49,413	$56,277	$49,473	$57,085	$52,297	$53,064	$52,347	$52,984	$52,500	$52,831	$48,705	$49,680	$55,518	$49,285	$53,202	$64,829	$52,710
Retire 1 Unit 2020, 1 Unit 2023 Replace with 75% Renewables - Wind, Solar, & DSM**	27C	$52,981	$49,751	$56,563	$49,769	$57,431	$52,612	$53,381	$52,663	$53,300	$52,849	$53,113	$49,010	$49,987	$55,844	$49,594	$53,540	$65,166	$53,026

* Updated version of scenario from January 2, 2015 filing

** New scenario for March 16, 2015 Supplement.

Table 7: PVSC/PVRR Total ($M) for all Scenarios, Sensitivities R-RU

SCENARIO	Number	R DON'T MAINTAIN CAPCON LENGTH	S MARKETS ON	T ND ASSUM-PTIONS	U CUSTO-MER IMPACT	V LOW WIND & LOW SOLAR	W LOW WIND & ZERO CO2	X ND LOAD REMOVED	CT LOW GAS & ZERO CO2	DT HIGH GAS & ZERO CO2	GT LOW WIND & ZERO CO2	HT HIGH WIND & ZERO CO2	IT LOW SOLAR & ZERO CO2	JT HIGH SOLAR & ZERO CO2	AT LOW LOAD & ZERO CO2	BT HIGH LOAD & ZERO CO2	RT DON'T MAINTAIN CAPCON LENGTH & ZERO CO2	RU DON'T MAINTAIN CAPCON LENGTH & CUST IMPACT
Reference Case*	1	$52,422	$52,049	$45,647	$45,933	$52,333	$47,498	$49,542	$42,353	$50,271	$45,516	$45,777	$45,647	$45,647	$42,772	$48,828	$45,605	$45,934
Reference Case with SCRs*	1B	$52,698	$52,325	$45,923	$46,209	$52,609	$47,775	$49,818	$42,629	$50,548	$45,792	$46,054	$45,923	$45,923	$43,049	$49,105	$45,882	$46,211
Retire 1 Unit 2025 Replace with 2x1 CC*	2	$52,551	$52,173	$45,949	$46,248	$52,462	$47,756	$49,683	$42,577	$50,668	$45,818	$46,080	$45,949	$45,949	$43,054	$49,136	$45,908	$46,249
Retire 1 Unit 2025 Replace with CTs*	3	$52,553	$52,138	$45,929	$46,256	$52,465	$47,740	$49,675	$42,545	$50,662	$45,798	$46,060	$45,929	$45,929	$43,044	$49,136	$45,888	$46,257
Retire 1 Unit 2025 Replace with 50% Renewables - Wind*	4A	$52,515	$52,151	$46,014	$46,288	$52,371	$47,741	$49,632	$42,715	$50,637	$45,828	$46,200	$46,014	$46,014	$43,131	$49,194	$45,972	$46,289
Retire 1 Unit 2025 Replace with 50% Renewables - Wind & Solar*	4B	$52,426	$52,060	$45,935	$46,220	$52,268	$47,693	$49,553	$42,653	$50,535	$45,782	$46,087	$45,887	$45,982	$43,049	$49,111	$45,893	$46,221
Retire 1 Unit 2025 Replace with 50% Renewables - Wind, Solar, & DSM*	4C	$52,785	$52,386	$46,277	$46,610	$52,627	$48,033	$49,917	$42,975	$50,906	$46,124	$46,430	$46,251	$46,303	$43,437	$49,436	$46,256	$46,611
Retire 1 Unit 2025 Replace with 75% Renewables - Wind*	5A	$52,490	$52,154	$46,112	$46,380	$52,279	$47,744	$49,616	$42,929	$50,576	$45,859	$46,365	$46,112	$46,112	$43,228	$49,281	$46,070	$46,381
Retire 1 Unit 2025 Replace with 75% Renewables - Wind & Solar*	5B	$52,353	$52,009	$45,962	$46,271	$52,135	$47,664	$49,506	$42,778	$50,428	$45,776	$46,148	$45,888	$46,035	$43,066	$49,131	$45,920	$46,272
Retire 1 Unit 2025 Replace with 75% Renewables - Wind, Solar, & DSM*	5C	$52,706	$52,350	$46,312	$46,630	$52,489	$48,008	$49,860	$43,117	$50,797	$46,126	$46,498	$46,260	$46,365	$43,456	$49,457	$46,292	$46,631
Retire 2 Units 2025 Replace with 2x1 CCs*	6	$52,702	$52,298	$46,291	$46,580	$52,613	$48,046	$49,802	$42,817	$51,131	$46,160	$46,421	$46,291	$46,291	$43,405	$49,500	$46,249	$46,581
Retire 2 Units 2025 Replace with CTs*	7	$52,766	$52,325	$46,338	$46,804	$52,677	$48,097	$50,023	$42,855	$51,190	$46,207	$46,469	$46,338	$46,338	$43,464	$49,549	$46,297	$46,805
Retire 2 Units 2025 Replace with 50% Renewables - Wind*	8A	$52,666	$52,157	$46,453	$46,727	$52,422	$48,008	$49,720	$43,177	$51,037	$46,167	$46,739	$46,453	$46,453	$43,618	$49,681	$46,412	$46,728
Retire 2 Units 2025 Replace with 50% Renewables - Wind & Solar*	8B	$52,490	$51,996	$46,293	$46,612	$52,228	$47,910	$49,575	$43,042	$50,843	$46,074	$46,513	$46,209	$46,378	$43,442	$49,528	$46,252	$46,613
Retire 2 Units 2025 Replace with 50% Renewables - Wind, Solar, & DSM*	8C	$52,849	$52,331	$46,643	$46,973	$52,587	$48,256	$49,935	$43,376	$51,217	$46,424	$46,863	$46,580	$46,706	$43,829	$49,837	$46,623	$46,974
Retire 2 Units 2025 Replace with 75% Renewables - Wind*	9A	$52,639	$52,202	$46,612	$46,922	$52,294	$48,026	$49,768	$43,523	$50,942	$46,226	$46,999	$46,612	$46,612	$43,754	$49,789	$46,571	$46,923
Retire 2 Units 2025 Replace with 75% Renewables - Wind & Solar*	9B	$52,343	$51,926	$46,349	$46,616	$51,967	$47,854	$49,443	$43,303	$50,620	$46,063	$46,636	$46,218	$46,481	$43,491	$49,536	$46,308	$46,617
Retire 2 Units 2025 Replace with 75% Renewables - Wind, Solar, & DSM*	9C	$52,712	$52,274	$46,702	$47,030	$52,341	$48,204	$49,838	$43,633	$51,007	$46,416	$46,988	$46,597	$46,807	$43,880	$49,865	$46,681	$47,030
Preferred Plan*	10	$52,083	$51,740	$45,960	$46,228	$51,647	$47,456	$49,244	$43,157	$49,924	$45,625	$46,296	$45,824	$46,097	$43,168	$49,071	$45,924	$46,229
Preferred Plan with PTC*	10A	$51,262	$50,920	$45,216	$45,485	$51,027	$46,882	$48,450	$42,366	$49,251	$45,083	$45,350	$45,080	$45,353	$42,433	$48,315	$45,181	$45,485
Preferred Plan with Retire 1 Unit 2025*	10B	$52,187	$51,852	$46,206	$46,471	$51,751	$47,664	$49,349	$43,348	$50,234	$45,871	$46,541	$46,069	$46,342	$43,386	$49,330	$46,170	$46,472
Preferred Plan with Retire 1 Unit 2025 & PTC*	10C	$51,366	$51,033	$45,462	$45,728	$51,132	$47,091	$48,555	$42,558	$49,561	$45,328	$45,595	$45,325	$45,598	$42,653	$48,574	$45,426	$45,728
Preferred Plan with Retire 1 Unit 2020**	10D	$52,159	$51,816	$46,370	$46,583	$51,786	$47,792	$49,269	$43,446	$50,475	$46,035	$46,705	$46,234	$46,507	$43,464	$49,553	$46,272	$46,542
Preferred Plan with Retire 2 Units 2020**	10E	$52,399	$51,989	$46,971	$47,213	$52,016	$48,294	$49,488	$43,902	$51,245	$46,635	$47,306	$46,834	$47,107	$44,016	$50,177	$46,878	$47,151
Preferred Plan with Retire 1 Unit 2020, 1 Unit 2023**	10F	$52,330	$51,980	$46,798	$47,044	$51,957	$48,152	$49,464	$43,774	$51,022	$46,463	$47,133	$46,661	$46,934	$43,861	$49,986	$46,699	$47,002
Preferred Plan with Retire 2 Units 2025*	10G	$52,399	$52,149	$46,636	$46,949	$51,964	$48,039	$49,658	$43,742	$50,698	$46,301	$46,971	$46,499	$46,773	$43,681	$49,702	$46,600	$46,950
Convert 1 Unit to Gas Boiler*	11	$52,449	$52,060	$45,888	$46,159	$52,360	$47,684	$49,542	$42,497	$50,627	$45,757	$46,019	$45,888	$45,888	$42,986	$49,082	$45,847	$46,160
Convert 2 Units to 4x1 CC*	12	$52,437	$51,994	$46,071	$46,412	$52,218	$47,790	$49,511	$42,612	$50,883	$45,941	$46,202	$46,071	$46,071	$43,123	$49,396	$46,215	$46,511
North Dakota Plan*	15	$52,620	$52,147	$45,517	$45,741	$52,723	$47,592	$49,750	$41,951	$50,506	$45,517	$45,517	$45,517	$45,517	$42,636	$48,762	$45,473	$45,761
Retire 1 Unit 2020 Replace with 2x1 CC**	16	$52,583	$52,224	$46,204	$46,450	$52,549	$47,966	$49,683	$42,774	$50,988	$46,073	$46,335	$46,204	$46,204	$43,237	$49,416	$46,106	$46,409
Retire 1 Unit 2020 Replace with CTs**	17	$52,579	$52,213	$46,195	$46,453	$52,545	$47,957	$49,688	$42,764	$50,980	$46,064	$46,325	$46,195	$46,195	$43,214	$49,410	$46,098	$46,455
Retire 1 Unit 2020 Replace with 50% Renewables - Wind**	18A	$52,652	$52,251	$46,377	$46,673	$52,479	$48,022	$49,772	$43,005	$51,095	$46,167	$46,586	$46,377	$46,377	$43,493	$49,565	$46,341	$46,674
Retire 1 Unit 2020 Replace with 50% Renewables - Wind & Solar**	18B	$52,598	$52,195	$46,334	$46,626	$52,401	$48,017	$49,713	$42,981	$51,029	$46,165	$46,502	$46,268	$46,399	$43,447	$49,520	$46,297	$46,626
Retire 1 Unit 2020 Replace with 50% Renewables - Wind, Solar, & DSM**	18C	$52,912	$52,483	$46,625	$46,962	$52,730	$48,309	$50,032	$43,254	$51,343	$46,456	$46,793	$46,588	$46,661	$43,774	$49,807	$46,602	$46,962
Retire 1 Unit 2020 Replace with 75% Renewables - Wind**	19A	$52,679	$52,310	$46,567	$46,858	$52,420	$48,093	$49,820	$43,303	$51,145	$46,275	$46,859	$46,567	$46,567	$43,696	$49,732	$46,533	$46,858
Retire 1 Unit 2020 Replace with 75% Renewables - Wind & Solar**	19B	$52,607	$52,226	$46,471	$46,796	$52,326	$48,083	$49,761	$43,210	$51,046	$46,262	$46,681	$46,370	$46,573	$43,587	$49,634	$46,442	$46,797
Retire 1 Unit 2020 Replace with 75% Renewables - Wind, Solar, & DSM**	19C	$52,872	$52,496	$46,736	$47,057	$52,616	$48,346	$50,024	$43,466	$51,324	$46,527	$46,945	$46,664	$46,808	$43,870	$49,904	$46,710	$47,057
Retire 2 Units 2020 Replace with 2x1 CCs**	20	$52,833	$52,389	$46,846	$47,105	$52,800	$48,503	$49,890	$43,234	$51,842	$46,715	$46,977	$46,846	$46,846	$43,856	$50,112	$46,747	$47,046
Retire 2 Units 2020 Replace with CTs**	21	$52,859	$52,392	$46,854	$47,128	$52,814	$48,512	$49,914	$43,239	$51,854	$46,723	$46,985	$46,854	$46,854	$43,944	$50,121	$46,769	$47,128
Retire 2 Units 2020 Replace with 50% Renewables - Wind**	22A	$52,909	$52,509	$47,245	$47,579	$52,610	$48,615	$50,072	$43,891	$51,921	$46,912	$47,578	$47,245	$47,245	$44,313	$50,410	$47,212	$47,581
Retire 2 Units 2020 Replace with 50% Renewables - Wind & Solar**	22B	$52,780	$52,422	$47,146	$47,448	$52,452	$48,590	$49,942	$43,830	$51,769	$46,896	$47,397	$47,031	$47,262	$44,199	$50,313	$47,109	$47,449
Retire 2 Units 2020 Replace with 50% Renewables - Wind, Solar, & DSM**	22C	$53,091	$52,681	$47,426	$47,755	$52,776	$48,873	$50,241	$44,078	$52,096	$47,176	$47,677	$47,339	$47,513	$44,520	$50,597	$47,404	$47,755
Retire 2 Units 2020 Replace with 75% Renewables - Wind**	23A	$52,959	$52,500	$47,466	$47,822	$52,543	$48,878	$50,139	$44,235	$51,984	$47,009	$47,922	$47,466	$47,466	$44,594	$50,655	$47,425	$47,824
Retire 2 Units 2020 Replace with 75% Renewables - Wind & Solar**	23B	$52,768	$52,318	$47,306	$47,588	$52,288	$48,629	$49,879	$44,118	$51,771	$46,973	$47,639	$47,125	$47,487	$44,438	$50,495	$47,273	$47,589
Retire 2 Units 2020 Replace with 75% Renewables - Wind, Solar, & DSM**	23C	$53,074	$52,605	$47,584	$47,915	$52,617	$48,909	$50,198	$44,374	$52,078	$47,251	$47,917	$47,439	$47,729	$44,746	$50,769	$47,563	$47,915
Retire 1 Unit 2020, 1 Unit 2023 Replace with 2x1 CC**	24	$52,763	$52,359	$46,650	$46,899	$52,727	$48,340	$49,832	$43,084	$51,596	$46,520	$46,781	$46,650	$46,650	$43,681	$49,898	$46,556	$46,901
Retire 1 Unit 2020, 1 Unit 2023 Replace with CTs**	25	$52,761	$52,351	$46,646	$46,892	$52,728	$48,337	$49,824	$43,078	$51,594	$46,515	$46,777	$46,646	$46,646	$43,669	$49,898	$46,549	$46,893
Retire 1 Unit 2020, 1 Unit 2023 Replace with 50% Renewables - Wind**	26A	$52,809	$52,437	$46,996	$47,313	$52,525	$48,418	$49,967	$43,689	$51,611	$46,677	$47,314	$46,996	$46,996	$44,067	$50,158	$46,962	$47,315
Retire 1 Unit 2020, 1 Unit 2023 Replace with 50% Renewables - Wind & Solar**	26B	$52,669	$52,298	$46,868	$47,145	$52,360	$48,364	$49,793	$43,578	$51,462	$46,627	$47,109	$46,762	$46,973	$43,942	$50,043	$46,831	$47,146
Retire 1 Unit 2020, 1 Unit 2023 Replace with 50% Renewables - Wind, Solar, & DSM**	26C	$52,996	$52,613	$47,184	$47,499	$52,699	$48,678	$50,145	$43,881	$51,797	$46,943	$47,425	$47,105	$47,264	$44,287	$50,341	$47,161	$47,499
Retire 1 Unit 2020, 1 Unit 2023 Replace with 75% Renewables - Wind**	27A	$52,868	$52,430	$47,220	$47,572	$52,471	$48,490	$50,052	$44,035	$51,679	$46,783	$47,657	$47,220	$47,220	$44,351	$50,391	$47,181	$47,573
Retire 1 Unit 2020, 1 Unit 2023 Replace with 75% Renewables - Wind & Solar**	27B	$52,633	$52,209	$47,009	$47,289	$52,182	$48,386	$49,749	$43,871	$51,407	$46,691	$47,327	$46,843	$47,175	$44,141	$50,191	$46,977	$47,291
Retire 1 Unit 2020, 1 Unit 2023 Replace with 75% Renewables - Wind, Solar, & DSM**	27C	$52,960	$52,517	$47,313	$47,659	$52,531	$48,692	$50,110	$44,151	$51,742	$46,994	$47,631	$47,181	$47,445	$44,473	$50,473	$47,292	$47,659

* Updated version of scenario from January 2, 2015 filing

** New scenario for March 16, 2015 Supplement

CERTIFICATE OF SERVICE

I, Tiffany Hughes, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota; or

xx by courier; or

xx by electronic filing.

Docket No. E002/RP-15-21

Dated this 16th day of March 2015

/s/

Tiffany Hughes

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Aafedt	daafedt@winthrop.com	Winthrop & Weinstine, P.A.	Suite 3500, 225 South Sixth Street Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_15-21_RP-15-21
Jorge	Alonso	jorge.alonso@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_15-21_RP-15-21
Alison C	Archer	alison.c.archer@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Andrew	Bahn	Andrew.Bahn@state.mn.us	Public Utilities Commission	121 7th Place E., Suite 350 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Ryan	Barlow	Ryan.Barlow@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota Street Bremer Tower, Suite 1400 St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
James J.	Bertrand	james.bertrand@leonard.com	Leonard Street & Deinard	150 South Fifth Street, Suite 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_RP-15-21
Michael	Bradley	mike.bradley@lawmoss.com	Moss & Barnett	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_RP-15-21
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_RP-15-21

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Aakash	Chandarana	Aakash.Chandara@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Jeanne	Cochran	Jeanne.Cochran@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 St. Paul, MN 55164-0620	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_15-21_RP-15-21
Leigh	Currie	lcurrie@mncenter.org	Minnesota Center for Environmental Advocacy	26 E. Exchange St., Suite 206 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_15-21_RP-15-21
Jerry	Dasinger	jerry.dasinger@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Jeffrey A.	Daugherty	jeffrey.daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_RP-15-21
Dustin	Denison	dustin@appliedenergyinnovations.org	Applied Energy Innovations	4000 Minnehaha Ave S Minneapolis, MN 55406	Electronic Service	No	OFF_SL_15-21_RP-15-21
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, Fifth Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_RP-15-21

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_15-21_RP-15-21
John	Flumerfelt	jflumerfelt@calpine.com	CalpineCorporation	500 Delaware Ave. Wilmington, DE 19801	Electronic Service	No	OFF_SL_15-21_RP-15-21
Stephen	Fogel	Stephen.E.Fogel@XcelEnergy.com	Xcel Energy Services, Inc.	816 Congress Ave, Suite 1650 Austin, TX 78701	Electronic Service	No	OFF_SL_15-21_RP-15-21
Benjamin	Gerber	bgerber@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Robert	Harding	robert.harding@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Patrick	Hentges		City Of Mankato	P.O. Box 3368 Mankato, MN 560023368	Paper Service	No	OFF_SL_15-21_RP-15-21
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_15-21_RP-15-21
Tiffany	Hughes	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_15-21_RP-15-21
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	OFF_SL_15-21_RP-15-21

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_RP-15-21
Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_RP-15-21
Clark	Kaml	clark.kaml@state.mn.us	Public Utilities Commission	121 E 7th Place, Suite 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Mark J.	Kaufman	mkaufman@ibewlocal949.org	IBEW Local Union 949	12908 Nicollet Avenue South Burnsville, MN 55337	Electronic Service	No	OFF_SL_15-21_RP-15-21
Hank	Koegel	hank.koegel@edf-re.com	EDF Renewable Eenrgy	10 2nd St NE Ste 400 Minneapolis, MN 55413-2652	Electronic Service	No	OFF_SL_15-21_RP-15-21
Thomas G.	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_15-21_RP-15-21
Mara	Koeller	mara.n.koeller@xcelenergy.com	Xcel Energy	414 Nicollet Mall 5th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_15-21_RP-15-21
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_RP-15-21

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ganesh	Krishnan	ganesh.krishnan@state.mn.us	Public Utilities Commission	Suite 350121 7th Place East St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_15-21_RP-15-21
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_15-21_RP-15-21
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Susan	Mackenzie	susan.mackenzie@state.mn.us	Public Utilities Commission	121 7th Place E Ste 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Peter	Madsen	peter.madsen@ag.state.mn.us	Office of the Attorney General-DOC	Bremer Tower, Suite 1800 445 Minnesota Street St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_15-21_RP-15-21
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro	360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg, Manitoba R3C 2P4 Canada	Electronic Service	No	OFF_SL_15-21_RP-15-21

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Connor	McNellis	cmcnellis@larkinhoffman.com	Larkin Hoffman Daly & Lindgren Ltd.	8300 Norman Center Drive Suite 1000 Minneapolis, MN 55437	Electronic Service	No	OFF_SL_15-21_RP-15-21
Brian	Meloy	brian.meloy@stinsonleonard.com	Stinson,Leonard, Street LLP	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_RP-15-21
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_15-21_RP-15-21
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_RP-15-21
Dorothy	Morrissey	dorothy.morrissey@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
David W.	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	Suite 300 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_RP-15-21
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_15-21_RP-15-21
Joshua	Pearson	joshua.pearson@edf-re.com	EDF Renewable Energy	15445 Innovation Drive San Diego, CA 92128	Electronic Service	No	OFF_SL_15-21_RP-15-21
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_15-21_RP-15-21
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_15-21_RP-15-21

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_15-21_RP-15-21
Ron	Spangler, Jr.	rlspangler@otpco.com	Otter Tail Power Company	215 So. Cascade St. PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_15-21_RP-15-21
Sean	Stalpes	sean.stalpes@state.mn.us	Public Utilities Commission	121 E. 7th Place, Suite 350 Saint Paul, MN 55101-2147	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Byron E.	Starns	byron.starns@leonard.com	Leonard Street and Deinard	150 South 5th Street Suite 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_RP-15-21
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_RP-15-21
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_15-21_RP-15-21
Douglas	Tiffany	tiffa002@umn.edu	University of Minnesota	316d Ruttan Hall 1994 Buford Avenue St. Paul, MN 55108	Electronic Service	No	OFF_SL_15-21_RP-15-21
Kari L	Valley	kari.l.valley@xcelenergy.com	Xcel Energy Service Inc.	414 Nicollet Mall FL 5 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_15-21_RP-15-21

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_15-21_RP-15-21
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_15-21_RP-15-21
Jonathan G.	Zierdt	N/A	Greater Mankato Growth	1961 Premier Dr Ste 100 Mankato, MN 56001	Paper Service	No	OFF_SL_15-21_RP-15-21
Patrick	Zomer	Patrick.Zomer@lawmoss.com	Moss & Barnett a Professional Association	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_RP-15-21