10-YEAR PLAN FOR MAJOR GENERATION AND TRANSMISSION FACILITIES

TO THE

SOUTH DAKOTA
PUBLIC UTILITIES COMMISSION

SUBMITTED BY
NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION
JULY 2018

Xcel Energy®

Northern States Power Company d/b/a Xcel Energy
2018 South Dakota Ten-Year Plan
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Northern States Power Company, doing business as Xcel Energy (Xcel Energy or the Company), submits its 10-year plan to the South Dakota Public Utilities Commission as required by S.D. Admin. R. § § 20:10:21:02 to 20:10:21:21 and SDCL § 49-41B-3.[1]

These administrative rules and legislative provision require every utility that owns or operates, or plans within the next ten years to own or operate, energy conversion facilities to develop and submit a 10-year plan that contains the following:

(1) A description of the general location, size, and type of energy conversion facilities or transmission facilities of two hundred fifty kilovolts or more to be owned or operated by the utility during the ensuing ten years, as well as those facilities to be removed from service during the planning period;

(2) A description of the efforts by the utility to coordinate the plan with other utilities so as to provide a coordinated regional plan for meeting the utility needs of the region;

(3) A statement of the projected demand for the service rendered by the utility for the ensuing ten years and the underlying assumptions for the projection, with such information being as geographically specific as possible and a description of the manner and extent to which the utility will meet the projected demand; and

(4) Any other relevant information as may be requested by the commission.

We present the information required for our 10-year plan in sequence as provided in §§ 20:10:21:04 to 20:10:21:18 inclusive, and additionally provide any further information required by SDCL 49-41B03 along with the closest related administrative rule requirement.

Biennial Report

20:10:21:04 EXISTING ENERGY CONVERSION FACILITIES

This section outlines the Company's electric generation facilities. We provide the details required by S.D. Admin. R. § § 20:10:21:04 for Company generating facilities located in South Dakota, and provide a list of the other generating facilities that comprise the NSP System that serves our South Dakota customers.[2]

Xcel Energy has one existing energy conversion facility in South Dakota. The table below provides the required information on this facility.

[1] The rules incorporate and put into effect the requirements outlined under S.D. Codified Laws § 49-41B-3

[2] The NSP System is comprised of electric generating plants and transmission facilities located and serving customers in the states of Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin.

South Dakota Electric Generating Facilities

Table 1. Angus C. Anson Plant

1	Location	Minnehaha County, South Dakota	
2	Type Nameplate Capacity	Simple Cycle Combustion Turbine 119.7 MW (unit 2) 119.7 MW (unit 3) 166.3 MW (unit 4)	
3	Net Capacity Annual Production	2016 Summer Winter 2017 Summer Winter 2016: 2017:	 90 MW (unit 2) 90 MW (unit 3) 147 MW (unit 4) 109 MW (unit 2) 109 MW (unit 3) 168 MW (unit 4) 90 MW (unit 2) 90 MW (unit 3) 147 MW (unit 4) 109 MW (unit 2) 109 MW (unit 3) 168 MW (unit 4) 65,698 MWh (total) 70,125 MWh (total)
4	Water Source and Annual Consumption	Ground Water 2016: 2017:	 7,482,510 gal 5,578,546 gal
5	Fuel Type Source Annual Consumption	Natural Gas Northern Natural Gas Co.[3] 2016: 805,279.64 MMBtu 2017: 845,279.92 MMBtu	Fuel Oil 2016: 103,380 gal 2017: 21,542 gal
6	Projected Retirement Date	Unit 2 & 3: Unit 4:	2026 2035

We provide a list of our other NSP System generating facilities and Power Purchase Agreements (PPA) as Appendix A to this report.

[3] The natural gas fuel is purchased from independent third party suppliers and delivered through the Northern Natural Gas interstate pipeline system.

20:10:21:05 PROPOSED ENERGY CONVERSION FACILITIES

This rule requires utilities to provide the specific electric generating facilities that have been proposed but are not yet in commercial operation in the 10-year period of the biennial report. In addition to providing the details for each of these planned facilities as required by S.D. Admin. R. § § 20:10:21:04, we note that the Company's Resource Plan proposes additional changes to its generation resources and mix. We provide a high level summary of our resource planning process and the procedural timeline for the proceeding in our Minnesota jurisdiction below.

Table 2

		Fox Tail Wind Farm	Blazing Star I Wind Farm
1	Location	**Ellendale, ND**	**Hendricks, MN**
2	Why Selected	**Competitive RFP bid**	**Competitive RFP bid**
3	Type Nameplate Capacity	**Wind** **150 MW**	**Wind** **200 MW**
4	Estimated Production	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**
5	Water Source	**NA**	**NA**
6	Fuel Type	**Wind**	**Wind**
7	Disposal Plans	**Not Applicable**	**Not Applicable**
8	Associated Facilities	**Montana-Dakota 230 kW Ellendale Tatanka Line**	**Brookings-Lyon 345 kW line**
9	Operating life with SD Fuels	**Not Applicable**	**Not Applicable**
10	Projected End of Life	**2044**	**2044**
11	Estimated Cost	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**
12	Projected In-Service Date	**2019**	**2019**

Table 3

		Blazing Star II Wind Farm	Freeborn Wind Farm
1	Location	Hendricks, MN	Glenville, MN
2	Why Selected	Competitive RFP bid	Competitive RFP bid
3	Type Nameplate Capacity	Wind 200 MW	Wind 200 MW
4	Estimated Production	**[TRADE SECRET BEGINS…** [redacted] **TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS…** [redacted] **TRADE SECRET ENDS]**
5	Water Source	NA	NA
6	Fuel Type	Wind	Wind
7	Disposal Plans	Not Applicable	Not Applicable
8	Associated Facilities	Brookings-Lyon 345 kW line	Glenworth 161 kV Substation
9	Operating life with SD Fuels	Not Applicable	Not Applicable
10	Projected End of Life	2045	2045
11	Estimated Cost	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**
12	Projected In-Service Date	2020	2020

Table 4

		Crowned Ridge Wind Farm	Crowned Ridge Purchase Agreement
1	Location	Watertown, SD	Watertown, SD
2	Why Selected	Competitive RFP bid	Competitive RFP bid
3	Type Nameplate Capacity	Wind 300 MW	Wind 300 MW
4	Estimated Production	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**
5	Water Source	NA	NA
6	Fuel Type	Wind	Wind
7	Disposal Plans	Not Applicable	Not Applicable
8	Associated Facilities	Otter Tail Power's Big Stone South Substation	Otter Tail Power's Big Stone South Substation
9	Operating life with SD Fuels	Not Applicable	Not Applicable
10	Projected End of Life	2044	2044
11	Estimated Cost	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**
12	Projected In-Service Date	2019	2019

Table 5

		Lake Benton Wind Farm	Clean Energy #1 Purchase Agreement
1	Location	Lake Benton, MN	Glen Ullin, ND
2	Why Selected	Competitive RFP bid	Competitive RFP bid
3	Type Nameplate Capacity	Wind 100 MW	Wind 100 MW
4	Estimated Production	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**
5	Water Source	NA	NA
6	Fuel Type	Wind	Wind
7	Disposal Plans	Not Applicable	Not Applicable
8	Associated Facilities	Buffalo Ridge and Chamarambie Substations	Square Butte substation
9	Operating life with SD Fuels	Not Applicable	Not Applicable
10	Projected End of Life	2044	2044
11	Estimated Cost	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**
12	Projected In-Service Date	2019	2019

Table 6

		Dakota Range I & II Wind Farm	Mankato Energy Center 2, Purchase Power Agreement
1	Location	Watertown, SD	Mankato, MN
2	Why Selected	Competitive RFP bid	Competitive RFP bid
3	Type Nameplate Capacity	Wind 300 MW	Combined Cycle 345 MW
4	Estimated Production	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS…** [redacted] **TRADE SECRET ENDS]**
5	Water Source	NA	NA
6	Fuel Type	Wind	Natural Gas
7	Disposal Plans	Not Applicable	Not Applicable
8	Associated Facilities	Big Stone South-Ellendale 345kV Line	Not Applicable
9	Operating life with SD Fuels	Not Applicable	Not Applicable
10	Projected End of Life	2046	2038
11	Estimated Cost	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**
12	Projected In-Service Date	2021	2019

Resource Planning Overview

Resource Planning is a complex and integrated process of planning for the capacity, energy, and emission requirements of the electric system. The process incorporates a number of key assumptions or industry projections that helps to inform a common vision of what the future planning environment may look like. This ongoing planning process requires utilities to examine and establish a long-term proposal for management, operation, and expansion or contraction of their generating and demand management resources to meet customer needs.

Traditionally the primary focus of resource planning has been to identify the least-cost approach to provide reliable service and meet growing demand. While these goals remain critical to the resource planning process, we have broadened the scope of planning considerations by incorporating new generation technologies, increasing renewable energy, reducing emission profiles, and evaluating the retirement of large baseload facilities, thereby positioning the NSP System for the future.

The planning landscape underlying the Resource Plan greatly informs the planning efforts. We believe that proactive leadership in the face of evolving industry, new and proposed environmental regulation, customer expectations, emerging technologies, and changes to the NSP System will allow us to affirmatively address these trends rather than being shaped by them. Our planning also calls for sufficient flexibility to allow us to adjust and react as we gain more clarity on the planning landscape.

The criteria we apply as as we evaluate and propose our preferred plan in relation to a reference plan is its ability to: (1) maintain or improve the adequacy and reliability of utility service; (2) keep customers' bills and our rates as low as practicable, given regulatory and other constraints; (3) minimize adverse socioeconomic effects and adverse effects upon the environment; (4) enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and (5) limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

The Company filed the 2016-2030 Upper Midwest Resource Plan (IRP) on January 2, 2015, and filed a substantive supplement on January 29, 2016. The Minnesota Public Utilities Commission approved the IRP in October 2016. The approved plan was developed to address the planning landscape in which it was developed – and based on five key considerations:

- The solid foundation that has resulted from our investment cycle;
- Innovative use of renewable energy to drive down emissions and preserve flexibility;
- Strategic flexibility;
- Cost effectiveness; and
- A plan to address the future of Sherco Units 1 and 2.

The preferred plan for our Upper Midwest customers builds on our strong foundation of environmental performance, while continuing to reliably meet our customers' electricity needs in a cost-effective mannerThe Company plans to file its next IRP onFebruary 1, 2019.

20:10:21:06 EXISTING TRANSMISSION FACILITIES

This rule requires utilities to provide a description of its existing transmission facilities. Similar to the information we provided about our electric generating facilities, we provide the details required by S.D. Admin. R. § § 20:10:21:04 for Company transmission facilities located in South Dakota, and provide information about other transmission facilities that comprise the NSP System that serves our South Dakota customers as Appendix B.

<u>**South Dakota Transmission Facilities**</u>

Listed below are our existing transmission facilities operating at 115 kV or above in South Dakota. They are all located in the eastern portion of the state. As noted above, a map showing the location of our transmission lines is included as Appendix B. Currently none of these facilities are projected to be removed from service.

A. Type 115 kV – AC

1. Lawrence Substation in Sioux Falls to the Lincoln County Substation south of Sioux Falls – 11 miles.
2. Lincoln County Substation south of Sioux Falls to the Louise Substation (southwest side of Sioux Falls) – 3 miles.
3. Louise Substation (southwest corner of Sioux Falls) to the Cherry Creek Substation (west side of Sioux Falls) – 7 miles.
4. Cherry Creek Substation to the Grant Substation west of Sioux Falls – 24 miles.
5. Grant Substation west of Sioux Falls to Northwestern Energy (Northwestern) at Mitchell – 24 miles to Wolf Creek Interconnection owned by Xcel Energy; the remainder is owned by Northwestern.
6. Lawrence Substation in Sioux Falls to the Western Area Power Administration (WAPA) Substation in Sioux Falls – 1 mile.
7. Lawrence Substation in Sioux Falls to the Split Rock Substation approximately 5 miles northeast of Sioux Falls (circuit #1) – 2 miles.
8. Split Rock Substation to the Pathfinder Substation to the Pipestone Substation in Pipestone, Minnesota. Approximately 35.5 miles of this line are in the state of South Dakota – 44.5 miles total.
9. Lawrence Substation in Sioux Falls to the Split Rock Substation approximately 5 miles northeast of Sioux Falls (circuit #2). Approximately 1 mile of this line is double-circuited with the Split Rock-Magnolia 161 kV line; 2.2 miles total.
10. Split Rock Substation to the West Sioux Falls Substation – 17.3 miles.
11. West Sioux Falls Substation to the Cherry Creek Substation – 3.5 miles.
12. Split Rock Substation to Renner Substation – 8.7 miles.
13. Renner Substation to Cherry Creek-7.8 miles.
14. Split Rock to Angus C. Anson generating plant – 0.28 miles.
15. Split Rock to Angus C. Anson generating plant # 2 – 0.43 miles.
16. Brookings County to Yankee #1 – 3.7 miles of this line is in South Dakota; 13 miles total.
17. Brookings County to Yankee #2 – 6.5 miles of this line is in South Dakota; 13 miles total.
18. West Sioux Falls to Falls Substation-3.6 miles
19. Falls Substation to Split Rock Substation-8.25 miles

B. Type 161 kV – AC

1. Split Rock Substation approximately 5 miles northeast of Sioux Falls to ITC Midwest, LLC (ITC Midwest) interconnection near Luverne, Minnesota.[4] Approximately 1 mile of this line is double-circuited with the second Lawrence- Split Rock 115 kV line. Approximately 11 miles of this line are in the state of South Dakota - 20 miles total.

C. Type 230 kV – AC

1. Split Rock Substation to the WAPA Sioux Falls Substation – 1 mile.

D. Type 345 kV – AC

1. Split Rock Substation northeast of Sioux Falls to the WAPA's 345 kV line to Watertown. This is a 5.1 mile line with 2.5 miles double circuit but one circuit is not energized.
2. Split Rock Substation northeast of Sioux Falls to the WAPA's 345 kV line to Sioux City. This is a double-circuit line – 5.1 miles with the Split Rock-Nobles line.
3. Split Rock-Nobles County-Lakefield Junction. 345 kV line approximately 10 miles of this line are in the state of South Dakota – 90.8 miles total. 5.1 miles are double circuit with the Split Rock-Sioux City line.
4. Brookings County-White 345 kV line #1. This is a 0.4 mile line.
5. Brookings County-White 345 kV line #2. This is a 0.4 mile line.
6. A 230 mile, 345 kV line between Brookings, South Dakota, and the southeast Twin Cities, plus a related 30 mile, 345 kV line between Marshall, Minnesota, and Granite Falls, Minnesota (Brookings Project).
7. Big Stone South to Brookings Co Substation is a 72 mile long line with the ownership split evenly between Xcel Energy and Otter Tail Power Company.

As noted above, a map of our total NSP System transmission facilities is provided as Appendix B to this report.

20:10:21:07 PROPOSED TRANSMISSION FACILITIES

This rule requires utilities to provide the specific transmission facilities that have been proposed but are not yet in operation in the 10-year period of the biennial report.

There are no transmission facilities proposed in the 10-year period. The transmission system is analyzed on an annual basis and any future projects will included when necessary.

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[4] In early 2008, ITC Midwest purchased all of the high voltage electric transmission facilities of Interstate Power and Light Company (Alliant Energy) in Iowa, Minnesota and Illinois.

20:10:21:08 COORDINATION OF PLANS

This rule requires utilities to describe how their plans coordinate with other utilities serving the region.

Xcel Energy is a member of the Midwest Reliability Organization (MRO). The purpose of the MRO is to ensure the reliability and security of the bulk power system covering the states of Wisconsin, Iowa, Minnesota, Nebraska, and most of South Dakota as well as the Canadian provinces of Saskatchewan and Manitoba. As such, the members of the non-profit organization meet to discuss reliability and security issues. There are numerous committees that develop standards, guidelines, and reporting procedures for everything from load shedding to vegetation management. More information about the organization can be found at: http://www.midwestreliability.org.

The Company is also a participant in the Minnesota Transmission Assessment & Compliance Team (MN-TACT) along with several other utilities covering Minnesota, Western Wisconsin and parts of North Dakota and South Dakota. The purpose of this analysis is to develop an understanding of the transmission system topology, behavior and operation. This analysis is performed to meet NERC Transmission Planning Standards TPL-001.

All major transmission planning performed by the Company is now coordinated through the MISO on a regional basis, consistent with the Federal Energy Regulatory Commission (FERC) Orders (a) dated May 19, 2000 (FERC Docket No. EC00-60-000) authorizing the transfer of functional control of our high voltage transmission system to the MISO; (b) dated December 20, 2001[5] finding the MISO to be the first FERC-approved regional transmission organization (RTO); and dated February 15, 2007 (Order No. 890), requiring RTOs and their member utilities to use coordinated regional planning.[6] MISO issues an annual MTEP after coordinated planning and stakeholder review. Prior to 2007, these plans were issued biennially. The current MTEP 2017 series of projects was approved by the MISO Board of Directors in December of 2017 and is available at the MISO website at www.misoenergy.org.

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[5] FERC Docket Nos. RT01-87-000, RT01-001, ER02-106-000 and ER02-108-000.

[6] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007) (Order No. 890), *order on reh'g*, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2008) (Order No. 890-A); *order on reh'g* 123 FERC ¶ 61,299 (Order No. 890B) (June 23, 2008). MISO's Order No. 890 regional transmission planning process was conditionally accepted for filing in *Midwest Independent Transmission System Operator, Inc.*, 123 FERC ¶ 61,164 (May 15, 2008).

As a result of complying with the FERC Order No. 890 rules, MISO has implemented its own Sub-Regional Planning Meetings. We participate in the Western Region meetings. This group provides a forum for stakeholder input and coordination of plans and we actively participate in this. This joint planning is intended to maximize use of existing facilities and minimize the amount of new facilities.

Another example of this coordination by the utilities is the formalization of the Minnesota Transmission Owners (MTO) organization. The MTO consists of all transmission owning utilities in Minnesota. The MTO was formed to submit coordinated biennial transmission planning reports to the Minnesota Commission as required by Minn. Stat. § 216B.2425. Some MTO utilities also serve eastern North Dakota and eastern South Dakota. The MTO group is presently developing coordinated short-term regional plans and longer term vision plans for the bulk transmission needs throughout the upper Midwest and the transmission required to meet the various states' Renewable Energy Standards. The MTO group also performs an annual 10-year assessment of the members' utility systems for compliance with the North American Electric Reliability Corporation Transmission Planning (TPL) standards. The MTO utilities also coordinate their planning with the CapX2020 planning processes and the MTEP processes.

We also participate in Interconnection-wide transmission planning, currently being facilitated under the Eastern Interconnection Planning Collaborative (EIPC) effort, funded by the Department of Energy. The EIPC effort is focused on a high level look at the transmission needs east of the Rocky Mountains (excluding parts of Texas).

In addition, as noted previously, the Company prepares Integrated Resource Plans for the NSP System and submits a copy of those plans to the Commission consistent with the Commission's requirements in Docket No. EL08-028 and the Settlement Stipulation and Commission Order in Docket No. EL09-009.

20:10:21:09 SINGLE REGIONAL PLANS

This rule requires utilities to state whether the facilities it has proposed comprise all or part of a single regional plan. As described in the previous sections, the Company serves its South Dakota customers from an integrated NSP System that serves portions of Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. We periodically evaluate our customers' needs and federal and state requirements, and develop Integrated Resource Plans that look 15 years into the future to ensure we continue to meet our reliability requirements and customer needs. We additionally continue to work with MISO and other coordinated regional utility groups to evaluate potential transmission needs in the future and to develop coordinated regional plans as required to meet those needs.

20:10:21:10 SUBMISSION OF REGIONAL PLANS
This rule requires utilities proposing facilities that comprise all or part of a regional plan to submit the plan(s). As noted previously, we submit our Integrated Resource Plans to the Commission as they are developed.

Regional transmission plans, by virtue of their geographic coverage, involve a collaborative effort of multiple utilities. As the CapX2020 effort has shown, we and the other utilities in this region are actively analyzing and developing coordinated regional plans. This analysis includes the active participation of the MTO and the MISO planning efforts. This effort is part of the MTEP regional planning process. As specific plans for additional facilities are developed, they will be submitted with subsequent 10-year plans. The MTEP is subject to review and approval by MISO's independent Board of Directors. Proposals to construct specific MTEP approved facilities in South Dakota would be submitted for Commission approval as required.

20:10:21:11 UTILITY RELATIONSHIPS
This rule requires utilities to describe any relationship of the utility to other utilities and regional associates, power pools, and networks.

Northern States Power Company-Minnesota (NSPM) is an operating company subsidiary of Xcel Energy Inc., a public utility holding company, and we are affiliated with three other regulated public utilities: Northern States Power Company-Wisconsin (NSPW), Public Service Company of Colorado, and Southwestern Public Service Company. NSPM is a member of MISO, the first FERC-approved RTO. As an RTO, MISO provides regional tariff administration services and operates a Day-ahead and Real-time regional wholesale energy market pursuant to its Open Access Transmission, Energy and Operating Reserve Markets Tariff. MISO implemented a regional planning reserve market in 2009, pursuant to Module E of the Open Access Transmission, Energy and Operating Reserve Markets Tariff. MISO is also the Regional Reliability Coordinator for the NSPM and NSPW integrated electric generation and transmission system (NSP System).

Outside of MISO, NSPM serves a small amount of retail load in Berthold, ND. For that, NSPM is also a transmission customer and market participant under Southwest Power Pool's Open Access Transmission Tariff.

We are also a member of the MRO, which is the Regional Entity responsible for enforcement of mandatory electric reliability standards adopted by the North American Electric Reliability Corporation.

20:10:21:12 EFFORTS TO MINIMIZE ADVERSE EFFECTS

This rule requires utilities to describe in detail its methodology used and efforts to identify, minimize, or avoid adverse environmental, social, economic, health, public safety, and historic or aesthetic preservation effects.

The Company uses a multi-step effort to minimize adverse effects resulting from siting, constructing, operating and maintaining large electric generating plants and high voltage transmission lines. These efforts relate to long-range planning and coordination, environmental site and route analysis, and to ensure the effects of construction and operation practices are minimized.

High voltage transmission facility plans are coordinated with MISO, other area power suppliers and load serving entities in order to develop, whenever possible, joint use facilities. Coordination with others can reduce the number of facilities by providing for joint ownership and operation of facilities.

Once the need for generation or transmission is identified, an initial site or route search is begun by defining a broad study area to locate the facility. A broad range of information about the physical, biological and cultural environment within the study area is then collected. As information on such factors as land use, air and water quality, plants and animals, transportation and social services, and local and regional employment becomes available, various siting criteria are used to define preferred and alternate routes and sites. We prefer to develop a project with the cooperative assistance of state and local agency officials, neighboring transmission utilities (such as Northwestern, WAPA, Missouri River Energy Services and ITC Midwest), and affected landowners in order to assure the widest possible considerations of information, concerns and options. It is our policy to ensure compliance with all local, state and federal regulatory requirements in the development and location of proposed projects.

Because of the detail involved in a major generation or transmission project, we continue to refine site and route engineering once permits have been granted. This allows us to adjust for new developments that may arise during construction, such as the need for changes in locations, land use or construction techniques, and allows any concerns to be addressed and mitigated without undue delay and expense. We are committed to working with affected landowners to mitigate environmental and land use problems which may arise as a result of construction and maintenance activities.

We discuss our other efforts to respond to the evolving utility landscape in our 2016-2030 Upper Midwest Integrated Resource Plan in Docket No. EL09-009.[7] For ease of reference, we provide the public version our January 29, 2016 Supplement as Appendix C to this 10-year plan.

20:10:21:13 LOAD MANAGEMENT EFFORTS

This rule requires utilities to describe its efforts toward efficient load management.

The Company's load management efforts in South Dakota reduce peak demands, especially during the summer months, which can help delay or avoid more expensive electric generation and purchased power needs.

On January 1, 2012 we launched a demand side management (DSM) program in South Dakota, approved in the Order in Docket No. EL11-013. The DSM portfolio includes load management, energy efficiency, and consumer education programs aimed at both residential and commercial customers.

Commercial programs in the DSM portfolio include:

- Lighting Efficiency (conservation)
- Business Saver's Switch (load management)
- Peak and Energy Control (load management)

Residential programs in the DSM portfolio include:

- Residential Home Lighting (conservation)
- Residential Saver's Switch (load management)
- Consumer Education

Since their launch, these programs have reduced peak demand by about 13.8 MW and have conserved almost 30 GWh. It is forecasted that in the next two years (2017-2019) the programs will achieve an additional 2.6 MW in peak reduction and 10 GWh.

We additionally provide details regarding the Company's load management and conservation efforts in our Resource Plan.

20:10:21:14 LIST OF REPORTS RELATED TO PROPOSED FACILITIES

This rule requires utilities to provide a list of all reports or studies filed or proposed to be filed with federal or other state agencies relating to the proposed facilities.

[7] *See* January 29, 2016 Supplement.

A. Electric Generation Facilities

Table 7. Electric Generation Facilities Reporting

Project Name	SD Docket No.	MN Docket No.	ND Case No.
Fox Tail Wind Farm	N/A	E002/M-16-777	PU-17-120
Blazing Star I Wind Farm	N/A	E002/M-16-777	PU-17-120
Blazing Star II Wind Farm	N/A	E002/M-16-777	PU-17-120
Freeborn Wind Farm	N/A	E002/M-16-777	PU-17-120
Crowned Ridge Wind Farm/PPA	EL-18-019	E002/M-16-777	PU-17-120
Lake Benton Wind Farm	N/A	E002/M-16-777	PU-17-120
Clean Energy #1 Purchase Agreement	N/A	E002/M-16-777	PU-17-120
Dakota Range I & II Wind Farm	EL-18-003	E002/M-17-694	PU-17-372
Mankato Energy Center 2/Purchase Agreement	N/A	E002/CN-12-1240	PU-15-096

B. Transmission Facilities

Minnesota Transmission Assessment and Compliance Team 2014 Transmission Assessment: December 2016

MTEP16 Report: December 2016

Minnesota Transmission Assessment and Compliance Team 2017 Transmission Assessment: February 2018

MTEP17 Report: December 2017

20:10:21:15 CHANGES IN STATUS OF FACILITIES

This rule requires utilities to list changes in the status of the utility's facilities during the past two years, or since submission of its most recent 10-year plan.

There have been no changes in the status of Xcel Energy's facilities in South Dakota in the past two years.

20:10:21:16 PROJECTED ELECTRIC DEMAND

This rule requires utilities to provide its projected customer demand for the 10-year period, in South Dakota and outside of South Dakota. Additionally, SDCL § 49-41B-3 requires utilities to describe the underlying assumptions for their projections, with such information being as geographically specific as possible – and a description of the manner and extent to which the utility will meet the projected demand.

As we have described, our South Dakota customers are served by the integrated NSP System, which is how we plan for and meet the needs of NSP System customers – including our South Dakota customers.

We produce long-range "median" forecasts of native energy requirements, summer peak, and winter peak demand. For planning purposes, we also develop a bandwidth (called semi-high and semi-low scenarios) to supplement our "median" forecasts. These two scenarios are intended to describe uncertainty in a business-as-usual context: a relatively narrow range of US economic growth with no basic change in the relationship between the regional and national economies. Tables 10, 12, and 12 below show the long-range system forecast of native energy requirements, summer peak, and winter peak demand for the NSP System. While this is how we plan and meet the needs of the NSP System, in compliance with Rule 20:10:21:16, we provide a forecast of our native energy requirements and peak demand for the State of South Dakota jurisdiction in Table 9 below.

The forecast for the NSP System is based on forecasts of jurisdictional sales by major customer class: residential with and without space heating, small commercial and industrial, and large commercial and industrial. Each customer class is modeled independently for the five states included in the NSP System. The native energy requirements are determined by applying a loss factor on total sales. The NSP System peak is apportioned to jurisdictions based on the native energy requirements by state and the load factor by state. Consequently, the summer and winter "peak loads" provided in Table 9 represent the South Dakota jurisdiction customer demand at time of total System seasonal peak demand. This "coincident" demand is appropriate for generating capacity_requirement forecasting.

It is important to note, however, that a "non-coincident" peak demand must be used in evaluating transmission_capacity requirements. This is because the transmission system must be able to supply the full local customer demand at all times. Due to load diversity caused by weather variations within the multi-state NSP System, peak customer demands in our South Dakota service areas can be as much as ten percent higher than the demands registered during the hour in which the total System peak demand occurs. It is these local "non-coincident" peak demands that determine the need for transmission improvements required for load serving functions.

We have described in our current Resource Plan how we propose to meet our customers' needs, federal and state policy requirements and objectives, and transition to the future, which we summarize below.

While forecasts are always subject to change, we expect to have sufficient capacity to meet our customers' needs through 2024. However, our current forecast indicates that beginning in 2025 our capacity position shifts from a surplus of nearly 500 MW to a deficit of over 2,200 MW by 2030. Much of this shift is due to the retirement of approximately 800 MW of peaking plants, as well as the expiration of nearly 1,700 MW of hydro and natural gas PPAs during the period, including the expiration of our existing 850 MW PPA with Manitoba Hydro in 2025.

Our plan proposes to address the capacity deficit through a combination of renewable resource additions in the early years, and the addition of natural gas CT and CC units. In summary, our proposed resource additions are:

- 1,400 MW of large solar additions, including 400 MW by 2020,
- 1,800 MW of additional wind, including 800 MW by 2020,
- A 786 MW CC addition at the Sherco site in 2026 to replace the capacity of Sherco Unit 1 before it ceases operation,
- A 230 MW CT located in North Dakota by the end of 2025, and
- Over 1,800 MW of additional CT capacity.

The early renewable energy additions we have proposed as part of our plan will allow us to capitalize on favorable market pricing associated with the recently extended Federal Investment Tax Credit and Production Tax Credit incentives, reducing the cost impacts of our proposed plan. Locating the proposed 786 MW Combined Cycle Unit at Sherco will allow us to cost-effectively address the transmission issues identified by the MISO Attachment Y2 Study, ensure the stability and reliability of our transmission system, mitigate impacts to the local community and our employees, and potentially provide improved access to natural gas supplies for communities in central Minnesota.

20:10:21:17 CHANGES IN ELECTRIC ENERGY

This rule requires utilities to show the increase or decrease in projected electric energy demand and allocation by volume and percentage for each year relative to the prior year.

We provide this information in Table 9 for our South Dakota service area for each year below.

Table 9. Forecast of Electric Energy Requirements & Peak Demand State of SD

	Summer Peak (MW)	Winter Peak (MW)	Energy (GWh)	Change In Energy (GWh)	% Change In Energy
2016	450	322	2,194		
2017	452	328	2,210	15	0.7%
2018	455	329	2,220	10	0.4%
2019	460	332	2,238	19	0.8%
2020	460	335	2,265	27	1.2%
2021	467	339	2,282	17	0.8%
2022	469	338	2,297	15	0.7%
2023	480	346	2,320	23	1.0%
2024	480	348	2,351	31	1.4%
2025	486	350	2,372	21	0.9%
2026	490	353	2,392	20	0.8%
2027	494	356	2,421	29	1.2%
2028	498	359	2,460	38	1.6%
2029	502	362	2,489	30	1.2%
2030	506	365	2,525	36	1.4%
2031	510	368	2,569	44	1.7%
2032	514	372	2,618	49	1.9%
2033	518	375	2,661	43	1.6%
2034	522	378	2,700	38	1.4%
Avg Annual Growth Rate 2016-2034 % growth:	**0.8%**	**0.8%**	**1.1%**		

1) Peak Load is ***coincident*** to the Xcel Energy system peak.
2) Winter Peak = MISO Winter Peak season, 2016 is –2016-2017 winter peak.
3) Peak Load forecast growth from 2026 - 2034 is based on average summer and winter SD peak growth rates from 2016 through 2025.

Table 10. NSP System Net Energy Requirements (MWh)

Year	Semi-Low (MWh)	Median (MWh)	Semi-High (GWh)
2016	43,989,457	45,064,055	46,262,752
2017	43,874,591	45,128,687	46,504,791
2018	43,656,152	45,062,182	46,585,860
2019	43,871,450	45,423,138	47,077,374
2020	43,947,404	45,616,130	47,400,653
2021	43,807,807	45,609,740	47,500,028
2022	43,845,079	45,766,856	47,779,829
2023	43,781,135	45,820,537	47,939,528
2024	43,805,327	45,966,956	48,192,850
2025	43,788,823	46,045,426	48,391,874
2026	43,751,308	46,128,476	48,571,673
2027	43,929,165	46,407,695	48,948,504
2028	44,242,272	46,844,261	49,511,025
2029	44,027,234	46,758,471	49,518,562
2030	44,393,402	47,238,280	50,133,084
2031	44,755,403	47,709,648	50,705,610
2032	45,195,700	48,267,360	51,421,776
2033	45,468,045	48,695,026	51,968,640
2034	45,700,827	49,048,008	52,466,651
Avg Annual Growth Rate 2016-2034 % growth:	**0.2%**	**0.4%**	**0.7%**

1) Semi-Low and Semi-High Scenarios reflect an 80%/20% Confidence Level NSP System Net Energy Requirements have been adjusted for DSM

Table 11. NSP System Net Summer Peak (MW)

Year	Semi-Low (MW)	Median (MW)	Semi-High (MW)
2016	8,229	8,507	8,860
2017	8,218	8,598	9,033
2018	8,190	8,633	9,136
2019	8,168	8,680	9,247
2020	8,131	8,701	9,327
2021	8,123	8,736	9,401
2022	8,084	8,758	9,470
2023	8,074	8,793	9,564
2024	8,028	8,786	9,604
2025	7,990	8,801	9,652
2026	7,961	8,798	9,698
2027	7,927	8,813	9,767
2028	7,909	8,820	9,815
2029	7,894	8,851	9,898
2030	7,917	8,913	9,978
2031	7,950	8,991	10,108
2032	7,993	9,066	10,219
2033	8,048	9,151	10,324
2034	8,086	9,234	10,451
Avg Annual Growth Rate 2016-2034 % growth:	**-0.1%**	**0.4%**	**0.9%**

1) Semi-Low and Semi-High Scenarios reflect an 80%/20% Confidence Level Net Peak Demand Adjusted for DSM

Table 12. NSP System Net Winter Peak (MW)

Year	Semi-Low (MW)	Median (MW)	Semi-High (MW)
2016	6,172	6,425	6,751
2017	6,131	6,474	6,846
2018	6,068	6,489	6,923
2019	6,058	6,529	7,009
2020	6,005	6,535	7,072
2021	5,989	6,569	7,153
2022	5,946	6,576	7,208
2023	5,932	6,606	7,257
2024	5,877	6,589	7,303
2025	5,832	6,596	7,341
2026	5,808	6,588	7,387
2027	5,798	6,608	7,438
2028	5,749	6,620	7,465
2029	5,767	6,658	7,584
2030	5,776	6,705	7,638
2031	5,826	6,785	7,752
2032	5,869	6,845	7,841
2033	5,895	6,912	7,946
2034	5,920	6,964	8,017
Avg Annual Growth Rate 2016-2034 % growth:	**-0.2%**	**0.4%**	**0.9%**

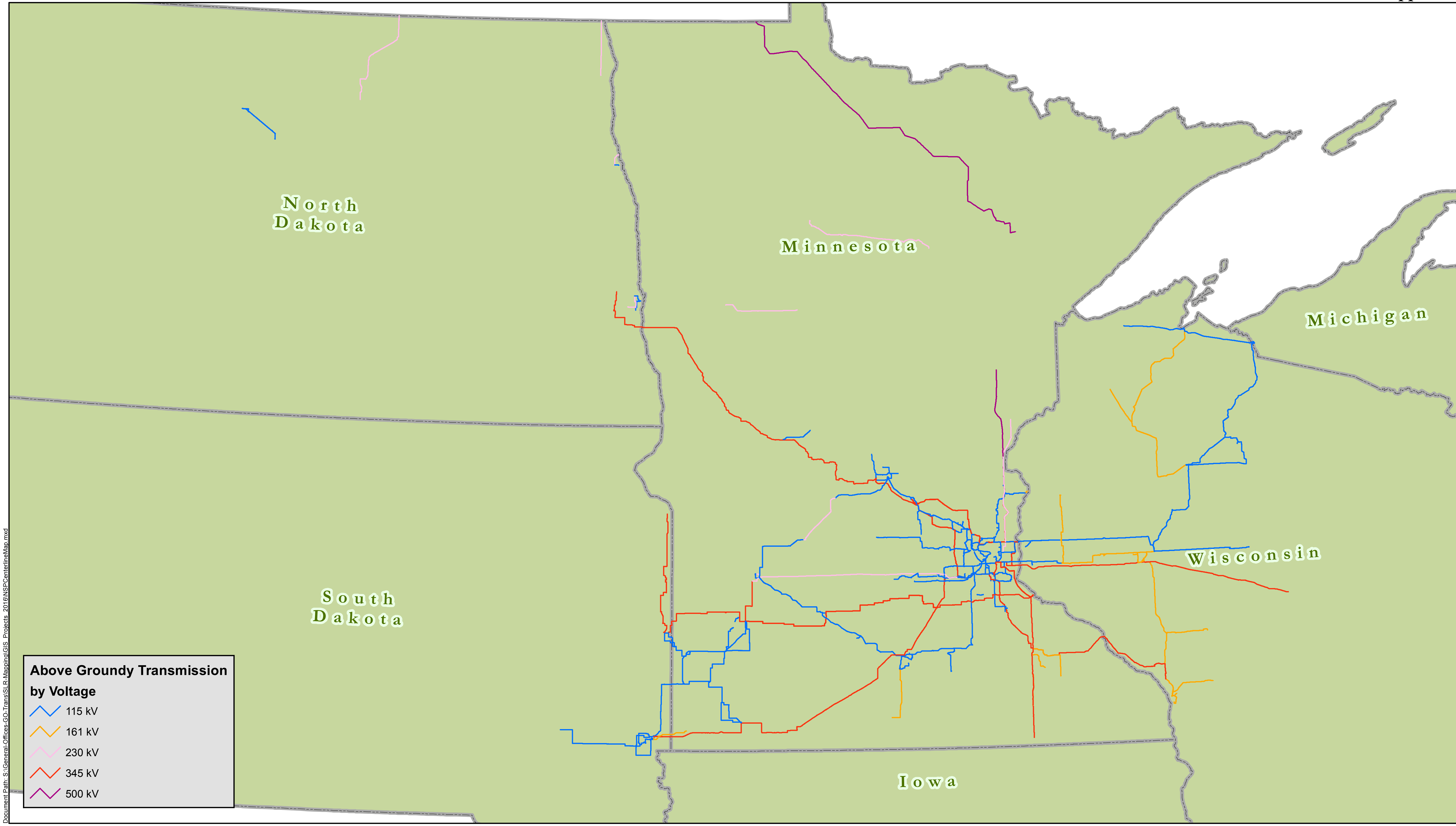
1) Winter Peak = Winter Peak season, 2015, is 2015-2016 winter peak.
2) Semi-Low and Semi-High Scenarios reflect an 80%/20% Confidence Level
3) Peak Adjusted for DSM

20:10:21:18 MAP OF SERVICE AREA
This rule requires utilities to provide a map or maps showing the specific geographic location of the utility's service area or areas.

We provide this information as Appendix D to this report.

NSP System Generating Resource Summary

Plant	Own/PPA	Type	Fuel
A.S. King	Owned	Thermal	Coal
Sherco 1, 2, 3	Owned	Thermal	Coal
Monticello	Owned	Thermal	Nuclear
Prairie Island 1, 2	Owned	Thermal	Nuclear
Black Dog 5/2	Owned	Combined Cycle	Natural Gas
High Bridge	Owned	Combined Cycle	Natural Gas
Riverside	Owned	Combined Cycle	Natural Gas
Cogentrix - Cottage Grove	PPA	Combined Cycle	Natural Gas
Calpine MEC 1	PPA	Combined Cycle	Natural Gas
Blue Lake 7, 8	Owned	Combustion Turbine	Natural Gas
Flambeau	Owned	Combustion Turbine	Natural Gas
Granite City 1-4	Owned	Combustion Turbine	Natural Gas
Inver Hills 1-6	Owned	Combustion Turbine	Natural Gas
Wheaton 1-4	Owned	Combustion Turbine	Natural Gas
Invenergy - Cannon Falls 1, 2	PPA	Combustion Turbine	Natural Gas
Bayfront 4	Owned	Thermal	Natural Gas
Blue Lake 1-4	Owned	Combustion Turbine	Oil
French Island 3, 4	Owned	Combustion Turbine	Oil
Wheaton 5, 6	Owned	Combustion Turbine	Oil
Bayfront 5, 6	Owned	Thermal	Biomass
French Island 1, 2	Owned	Thermal	Biomass
Red Wing 1, 2	Owned	Thermal	Biomass
Wilmarth 1, 2	Owned	Thermal	Biomass
Laurentian	PPA	Thermal	Biomass
KODA/Rahr	PPA	Thermal	Biomass
Fibrominn	PPA	Thermal	Biomass
St. Paul CoGen	PPA	Thermal	Biomass
MN Methane	PPA	Thermal	Biomass
Pine Bend	PPA	Thermal	Biomass
Hennepin Energy Recovery	PPA	Thermal	Biomass
Wind PPA's (1430 MW, nameplate)	PPA	Wind	Wind
Border Winds Wind Farm	Owned	Wind	Wind
Courtenay Wind Farm	Owned	Wind	Wind
Grand Meadow Wind Farm	Owned	Wind	Wind
Nobles Wind Farm	Owned	Wind	Wind
Pleasant Valley Wind Farm	Owned	Wind	Wind
Small Hydro PPA's (40 MW, nameplate)	PPA	Hydro	Hydro
MN Hydro - Owned	Owned	Hydro	Hydro
WI Hydro - Owned	Owned	Hydro	Hydro
Manitoba Hydro - PPA's (2)	PPA	Hydro	Hydro
Manitoba Hydro - Diversity Exchange	PPA	Hydro	Hydro



NSPM and NSPW Overhead Centerlines: 115 kV and Over

Updated: June 2018

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January 29, 2016

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—Via Electronic Filing —

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

RE: SUPPLEMENT – CURRENT PREFERRED PLAN
2016-2030 UPPER MIDWEST RESOURCE PLAN
DOCKET NO. E002/RP-15-21

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Supplement to its 2016-2030 Upper Midwest Resource Plan to the Minnesota Public Utilities Commission as required by its January 6, 2016 ORDER REQUIRING SUPPLEMENTAL FILING in the above-referenced docket.

This Supplement provides the detailed analysis supporting the proposal we outlined in our October 2, 2015 Reply Comments, as well as the information required in the Commission's January 6 Order. It also provides a detailed discussion of Prairie Island and our support for operating the plant through the end of each unit's respective current licensed life.

Our plan consists of the following:

- Accelerating our transition away from coal by ceasing coal operations at our Sherco Units 1 and 2 in the 2020s,
- Adding 1,400 megawatts of large solar to our system, including 400 megawatts by 2020,
- Adding 1,800 megawatts of wind, including 800 megawatts by 2020,
- Adding natural gas generation in the 2020s,
- Operating our carbon-free nuclear fleet through their existing plant licenses, and
- Continuing our commitment to increased energy efficiency and seeking out new technologies that will advance customer-driven solutions.

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Collaboration has been the hallmark of this proceeding. We developed the changes to our initial plan with input from stakeholders and believe our plan offers an energy vision that will benefit our customers, communities, and the states we serve. Together, the actions outlined in our Current Preferred Plan will result in a significant transformation in our generation fleet, including a nearly 60 percent reduction in our carbon emissions by 2030 without significantly impacting customer costs, reliability, Company employees, or the communities we serve. In fact, due to recent extensions to federal tax credits for solar and wind generation, the cost of our Current Preferred Plan is even lower than we anticipated in our October Reply Comments.

Request for Protection of Trade Secret Information
The Company recognizes and supports the need for transparency in review of our Resource Plan. Non-Public data included in this filing is limited to certain portions of the Supplement and four attachments as discussed below. We have identified the Trade Secret and other Non-Public information pursuant to Minn. Rule 7829.0500.

1. Forecasted Capital and O&M Costs

Section V of the Supplement contains forecasted cost details. This information is Trade Secret information as defined by Minn. Stat. §13.37(1)(b), because it derives independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, the Company maintains this information as a trade secret.

2. Attachment D – Grid Primer and Study Summary Report

Attachment D is a summary of the technical studies analyses the Company conducted to examine the technical impacts of potentially retiring Sherco Units 1 and 2. It is marked as Non-Public, as it contains Critical Electrical Infrastructure Information (CEII) including a summary of the results of the Midcontinent Independent System Operator Attachment Y2 Study and the Xcel Energy Transmission Reliability Study provided as Attachments D1, D2 and D3. Attachment D also discusses the Company's analysis of its Black Start Plan, which specifies the process of restoring the grid to full operation without relying on the external transmission network following a full- or partial-black out. Portions of this analysis are also CEII and marked as Trade Secret for the same security purposes noted in parts 3 and 4 below.

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3. Technical Study Reports

- *Attachment D1 - System Support Resource Attachment Y2 Study – The Sherburne County Generating Plant ("Sherco") Units 1 & 2 (Final Report of Midcontinent Independent System Operator (MISO) – August 28, 2015)*
- *Attachment D2 - Sherco 1 Replacement Power Study – Phase 1 (Siemens Power Technologies International - January 22, 2016)*
- *Attachment D3 - Sherco 1 and 2 Replacement Power Study – Phase 2 (Siemens Power Technologies International - January 22, 2016)*

Attachment D1 is marked as Non-Public in its entirety and is provided with critical infrastructure and highly-sensitive information redacted. Attachment D1 contains information regarding the MISO area grid, including specific information about the Xcel Energy and other transmission owner systems as it relates to the potential retirement of Xcel Energy's Sherburne County Generating Plant (Sherco) Units 1 and 2. While MISO has redacted all critical infrastructure and highly-sensitive information from the report, Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a).

Attachments D2 and D3 are marked as Non-Public in their entirety and contain CEII and highly-sensitive information redacted for the same reasons noted for Attachment D1. Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a). The reports by Siemens Power Technologies International resulted from studying the effects of potential retirement of one or both Sherco Units on the transmission system, and technical implications and upgrade costs associated with replacement of one or both Units at alternate locations on the NSP System. We believe that the information could potentially be used to determine vulnerabilities in the grid or in disrupting electric service to our customers, in the event Sherco Units 1 and or 2 were not in service. The public disclosure or use of this information creates an unacceptable risk, because those who want to disrupt the electrical grid may learn which facilities to target to create the greatest disruption. For this reason, pursuant to Minn. Stat. § 13.37, subd. 2, we have excised this data from the study results provided with this filing.

We take seriously our responsibility to maintain the security of the information and systems involved in the delivery of safe, reliable energy to our customers. A key tenet of our security program is limiting the extent to which sensitive information is accessed or shared. This is designed to help prevent key information about our system and the grid from being accessible. While we are not providing full Attachment Y2 and Siemens study reports available with this filing, we are open to

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discussing the specifics of the reports with parties to this docket who have signed a supplementary Non-Disclosure Agreement, provided that the information would remain adequately protected. Alternatively, the Company will make the full study reports available for inspection by Xcel Energy regulators who have fulfilled MISO's CEII requirements and will also consider making them available to certain other parties to the proceeding who have fulfilled MISO's CEII requirements and Xcel Energy's supplementary non-disclosure requirements.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service list. Interested parties will be able to obtain copies from our web site at:

http://www.xcelenergy.com/Company/Rates_&_Regulations/Resource_Plans.

Please contact me at (612) 215-4663 or Aakash.Chandarana@xcelenergy.com if you have any questions regarding this filing.

/s/

AAKASH H. CHANDARANA
REGIONAL VICE-PRESIDENT
RATES AND REGULATORY AFFAIRS

Enclosures
c: Service List

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SUPPLEMENT TO XCEL ENERGY'S 2016-2030 UPPER MIDWEST RESOURCE PLAN

DOCKET NO. E002/RP-15-21

JANUARY 29, 2016

2016-2030 Upper Midwest Resource Plan – Supplement
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ATTACHMENT D2 – Sherco 1 Replacement Power Study

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ATTACHMENT H - Preliminary Assessment of CO_2 Markets under the Clean Power Plan

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I. EXECUTIVE SUMMARY

Partnerships with communities, customers, and stakeholders have helped to make Minnesota a leader in energy policy - collaboration has been the hallmark of this proceeding. As our industry enters an era of increasing responsiveness to evolving expectations – from those of individual customers, to federal and state carbon emissions goals – these partnerships will become even more important to charting a path that provides certainty in uncertain times.

The Commission noted in its January 6, 2016 Order that resource planning is a collaborative and iterative process and that a full understanding of the relevant facts requires exposure to the views of engaged and knowledgeable stakeholders. The Commission also explained that the process of analyzing future energy needs and preparing to meet them is not a static process, and that strategies for meeting future needs evolve in response to changing conditions. We agree. Through significant collaboration with our stakeholders, our Current Preferred Plan has evolved from a plan that would achieve a 40 percent carbon dioxide emissions reduction from 2005 levels to one that achieves a nearly 60 percent reduction in the same timeframe.

After filing our initial resource plan in January 2015, we engaged in informal discussions and conducted several technical workshops to receive feedback from our stakeholders. We listened carefully to this feedback, we reviewed and analyzed the comments filed in this docket, and we shared an updated vision of our energy future that resulted from this collaboration in our October 2, 2015 Reply Comments.

As described in those Reply Comments, we envision an energy future that transitions our generation fleet such that we will achieve a dramatic reduction in carbon and by 2030, our energy mix will be 63 percent carbon-free. Taking action to transition our fleet now mitigates the costs and risks of retiring a significant proportion of our baseload generation in the same time period. It will also mitigate environmental regulatory risks that could affect the economic viability of our older coal units, and provides certainty to our customers and stakeholders throughout the planning period. Our proposal to achieve this vision will benefit our customers, states, and the communities we serve in a variety of ways. It will benefit our customers by providing for a cost-effective transition to the cleaner energy future they want, while preserving the reliable and safe service they expect. As discussed further below, we can accomplish this transition for just a fraction of a percent more in incremental cost over earlier plans.

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Our Current Preferred Plan will also benefit our states by advancing both federal and state energy policies and by being nearly certain to comply with the final Clean Power Plan rules. Finally, our Current Preferred Plan will benefit our communities. It allows adequate time to transition our workforce during this fleet evolution, and provides for new investments and the creation of new jobs in current and future host communities. For these reasons, we believe that our Current Preferred Plan charts the right path forward for our Company and stakeholders.

Our Current Preferred Plan consists of the following course of action:

- Accelerating our transition away from coal by ceasing operation of our Sherco Units 1 and 2 in the 2020s,
- Adding 1,400 megawatts of large solar to our system, including 400 megawatts by 2020,
- Adding 1,800 megawatts of wind, including 800 megawatts by 2020,
- Adding natural gas generation in the 2020s,
- Operating our carbon-free nuclear fleet through their existing plant licenses, and
- Continuing our commitment to increased energy efficiency and seeking out new technologies that will advance customer-driven solutions.

As we make this transition, maintaining the reliability of the system is critical. Our reliability studies confirm that, before ceasing coal operations at the second Sherco unit in 2026, we must take measures to maintain reliability. Our operational analysis confirms that the most cost-effective way to stabilize the transmission system and meet our customers' load requirements is to build a combined cycle plant at the existing Sherco site. By locating the plant at Sherco, we are able to use existing infrastructure and interconnection rights, which will result in significantly lower costs as compared to locating it elsewhere. We can also use our existing water allocation to wet-cool the plant, further improving cost and performance. Finally, we believe that the impacts on the Becker community should be properly considered in this proceeding, and the siting of a combined cycle at Sherco will promote economic development for the community. We also propose to add a combustion turbine near one of our load centers in North Dakota. This will balance the interests of the states that we serve and maintain the benefits of an integrated system for all of our customers, while also addressing the reliability concerns of the North Dakota commission, which wants the Company to build cost-effective and dispatchable generation in their state.

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We recognize that site-specific generation is not typically a part of traditional resource planning analysis. However, the plan components we are proposing will have wide-ranging impacts on our system and region, making a locational analysis imperative to ensuring continued reliability and maximizing customer benefits. For these reasons, and those discussed later in this Supplement, we believe that a locational analysis is appropriate and in the public interest.

Our ownership of these assets, along with a balanced portfolio of the renewable generation we propose to add to the system, is a critical component of our vision, because it results in a balanced generation portfolio that will minimize customer costs and mitigate risk. The specific benefits of ownership include investment in our communities, continued use of our interconnection rights at Sherco, long-term value for our customers arising from the asset life of owned resources, increased diversity in our generation portfolio, and a demonstration of our commitment to being a leading provider of cleaner and greener energy. Our ability to secure these benefits for our customers is a critical component of our Current Preferred Plan and, we believe, an important factor in the public interest analysis.

Finally, because our nuclear fleet comprises more than half of the Company's carbon-free generation, it is a cornerstone to our carbon-reduction goals. We continue, therefore, to support operating our nuclear fleet through the end of each plant's respective current licensed life. In October, we acknowledged our projected increase in the capital costs necessary to run the Prairie Island nuclear plant to the end of its current licensed life. At the hearing on December 3, 2015, the Commission sought additional information on the increased capital forecast, and we have since studied the Prairie Island numbers in greater depth. Two key conclusions emerged from this study. First, the lower fixed operating and maintenance costs we have experienced relative to our 2008 modeling projections more than offset the increased capital projections – by more than $950 million. Second, even with the increased capital costs (the bulk of which occur in 2021 and beyond), Prairie Island has been, and continues to be, a cost-effective resource.

We recognize however, that stakeholders would like to better understand the implications of our updated forecast, as well as the potential for future updates. To help promote a better understanding of these costs, we are including a detailed discussion of Prairie Island in this Supplement. We believe that this information supports our continued operation of the plant, including the near-term investments we must make to safely and reliably operate our plants over the next few years.
We acknowledge, however, that it is impossible to perfectly forecast costs for the

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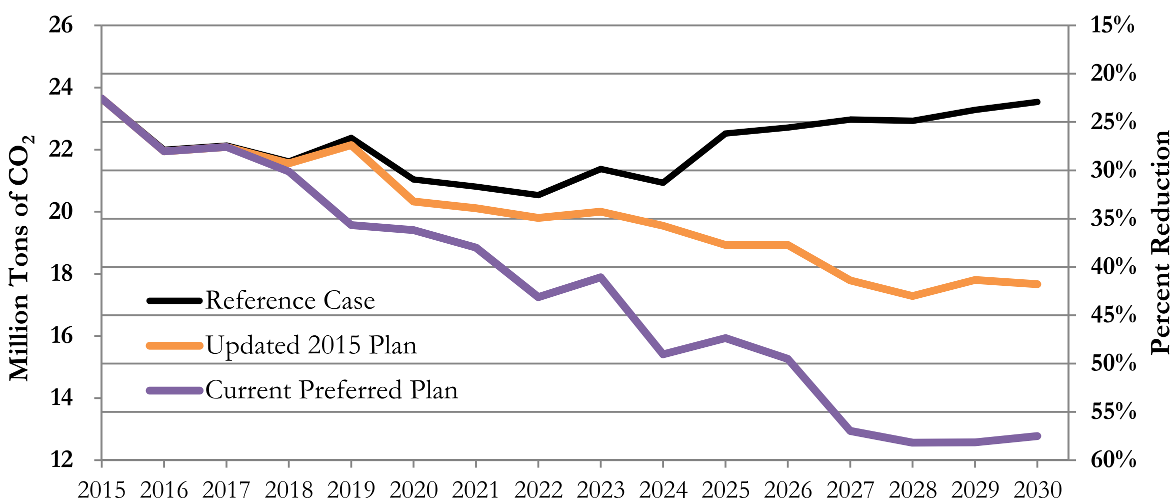
remaining 19 years of the plant's licensed life and recognize that stakeholders may want to explore alternatives based on that uncertainty. We therefore provide some preliminary analysis relating to an alternative path for Prairie Island (an "off-ramp") sometime in the mid-2020s. We recognize that there are other alternatives, but our analysis confirms that any near-term retirement would be significantly more costly than one in the mid-2020s or beyond. We agree that it makes sense to continue a dialogue regarding the future of Prairie Island. If the Commission wishes to further explore alternatives to operating Prairie Island through its current licenses, we are committed to doing the work necessary to advance this discussion, and anticipate that it could be completed within 18 months. At the same time, we believe that this Supplement demonstrates that the continued operation of Prairie Island is cost-effective and in the public interest in the near term, such that our continuing dialogue should not impede approval of our Current Preferred Plan.

Together, these actions will result in a significant transformation in our generation fleet, including a nearly 60 percent reduction in carbon emissions by 2030. The following graph shows the dramatically reduced carbon emissions that would result from our Current Preferred Plan, as compared to both our Updated 2015 Plan and Reference Case:



While the Updated 2015 Plan would have achieved substantial progress toward federal and state energy goals, the Current Preferred Plan – which grew out of the 2015 Plan through hard work and collaboration with stakeholders – does more. It

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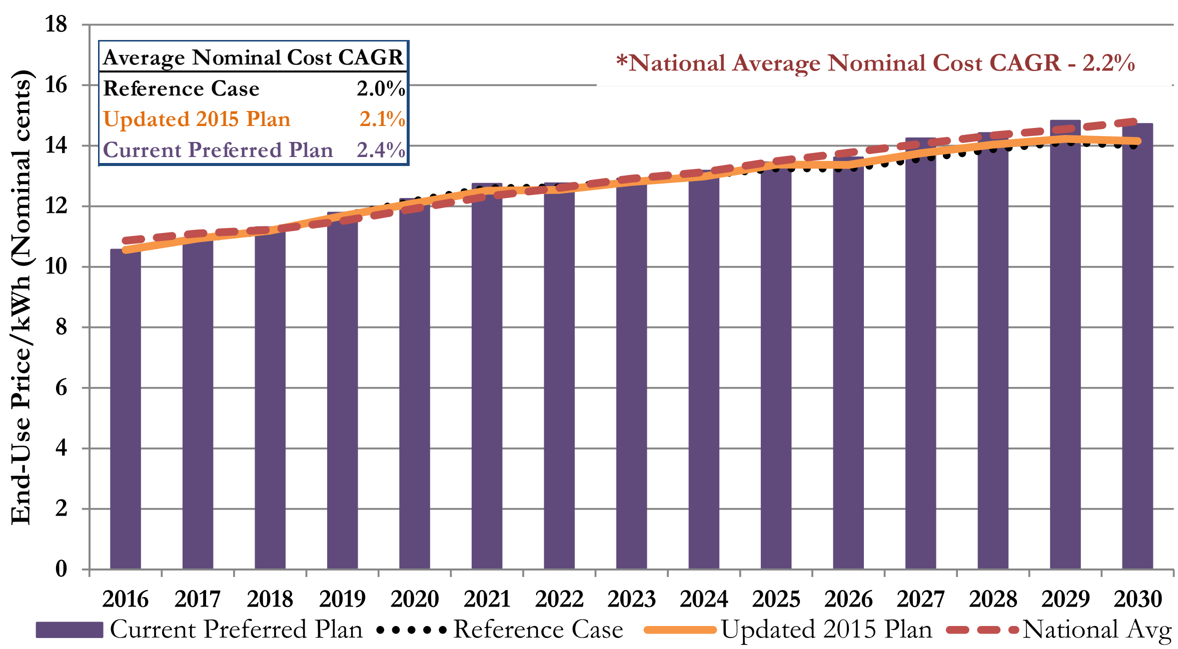
moves Minnesota significantly closer to achieving its goal of 80 percent carbon reduction by 2050, and it is the only scenario that is nearly certain to be compliant with the Clean Power Plan.

Our Current Preferred Plan achieves these goals without significantly impacting customer costs, reliability, our employees, or the communities we serve.
In fact, due to recent extensions to federal tax incentives for solar and wind generation, the cost of our Current Preferred Plan is even lower than we anticipated in our October Reply Comments. We can now offer a plan that achieves 50 percent more carbon reduction than our Updated 2015 Plan for a nominal customer cost of less than one-half of one percent Compound Annual Growth Rate (CAGR) over that plan. The opportunity to achieve such significant reductions in our carbon emissions for a nominal increase in customer cost is one of the principal benefits of our Current Preferred Plan, which is reflected in the Strategist modeling discussed in detail later in this supplement.

As we would expect, the trajectory of our Current Preferred Plan deviates from our Reference Case and Updated 2015 Plan mostly in the out years of the planning period, after we complete the transition away from coal operations at Sherco Units 1 and 2. The following graph shows the relative cost growth of our Current Preferred Plan, Updated 2015 Plan, and Reference Case, in comparison to the national average:



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*National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2015, Table Energy Supply, Disposition, Prices and Emissions. End use prices, all sector average.

As shown above, the cost of the three plans are comparable and roughly consistent with the expected national average increase in energy prices over the planning period.

Our Current Preferred Plan is in the public interest. It builds on our strong foundation of environmental performance, and ensures we will continue to reliably meet our customers' electricity needs in a cost-effective manner. It puts the Company on a path to transform its fleet in a planful, coordinated way that ensures we will meet our obligations under the Clean Power Plan and the most stringent of our state renewable energy and carbon reduction requirements. Implementation of our plan will put Minnesota at the forefront to lead the nation in clean energy, and at the same time, acknowledges and constructively addresses the unique policy preferences of the NSP System states. It provides our customers, employees, and communities with certainty while also maintaining flexibility to adjust and respond to changes along the way. Our Current Preferred Plan maintains a balanced diversity of energy sources and provides investment opportunities that will benefit the economies and communities in the states we serve. Finally, it promotes an orderly, gradual transition of our generation fleet and thus avoids a scenario where the Company may have to retire and replace five baseload generating facilities in the early 2030s.

To be sure, the process for approving this Resource Plan has taken longer than anticipated, and our Current Preferred Plan charts a path that is longer still. We believe, however, that a fleet transformation of this magnitude and scope requires a deliberate process, and that our Current Preferred Plan is a direct result of our deep engagement with stakeholders throughout this process. We have completed an extensive analysis since our October Reply, as well as in response to the Commission's January 6, 2016 Order. We are therefore appreciative of this opportunity to share our analysis and additional information in support of our Current Preferred Plan and look forward to engaging with our stakeholders to continue the constructive dialogue that brought us this far.

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 Competitive Acquisition Process (CAP) proceeding, which was an outcome from our last

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Resource Plan.[1] The Commission made determinations in that proceeding in December 2014, which, due to the timing, we were unable to incorporate into our Initial Filing.

On January 16, 2015, the Commission issued a NOTICE requiring the Company to supplement its Resource Plan with a revised Preferred Plan that incorporated the CAP resource decisions. On March 16, 2015, we submitted a Supplement incorporating the CAP resources, the 187 MW Solar RFP Portfolio the Commission approved in February 2015 in Docket No. E002/M-14-162, an acceleration of small solar additions to reflect the Community Solar Gardens proceeding, and additional modeling and discussion that resulted from our stakeholder engagement.[2]

Parties commented on the completeness of our Resource Plan on April 3, 2015, and as part of our April 17, 2015 Reply to those Comments, we submitted a detailed five-year rate analysis of our updated Preferred Plan. On July 2, 2015, parties commented on our Preferred Plan.

On October 2, 2015, we replied to parties' comments, in part committing to maintain a goal of 1.5 percent Demand Side Management (DSM) through the planning period and find ways to stimulate greater demand response with our customers – and in addition, outlined a Revised Proposal that would transition our system from coal generation, advance the acquisition of significant levels of renewable generation, recognize nuclear energy as a critical carbon-free baseload resource, and confirm our commitment to energy efficiency efforts. We also proposed to supplement the record with a detailed analysis supporting our Revised Proposal on January 29, 2016.

On January 6, 2016, the Commission approved our request to submit a Supplement on January 29, 2016, and set forth several informational requirements for the Supplement.[3] The Commission's Order additionally set a 30-day period within which the Minnesota Department of Commerce (Department) is to submit a letter to the Commission recommending a comment period and whether any additional information is needed. After reviewing the Department's recommendation and recommendations from any other party, the Executive Secretary is authorized to set a Reply Comment period.

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[1] Docket No. E002/M-12-1240.
[2] Docket No. E002/M-14-162.
[3] *See* ORDER REQUIRING SUPPLEMENTAL FILING, Docket No. E002/RP-15-21 (January 6, 2016).

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We note that in this Supplement, we have updated the naming of our scenarios from our past filings to properly reflect our Current Preferred Plan for which we seek regulatory approval as follows:

January 2, 2015 Initial Filing	March 16, 2015 Supplement	October 2, 2015 Reply Comments	January 29, 2016 Supplement
Reference Case	Reference Case	Reference Case	Reference Case
Preferred Plan	Updated Preferred Plan	Preferred Plan	Updated 2015 Plan
N/A	N/A	Revised Proposal	Current Preferred Plan

The Updated 2015 Plan in this Supplement is named as such because we allowed our updated modeling for this scenario to select Production Tax Credit (PTC)- and Investment Tax Credit (ITC)-priced renewable resources, as a result of the December 2015 extension of these Federal tax incentives. Implementing this change allows for improved comparability of our Current Preferred Plan and our previous filings in this proceeding.

III. CURRENT PREFERRED PLAN

Our Current Preferred Plan proposes a bold energy vision that is centered around four principles:

First, accelerate the transition from coal energy to lower- and zero-carbon resources. Specifically we propose to:

- Achieve a reduction of in carbon dioxide (CO_2) emissions of nearly 60 percent (from 2005 levels) by 2030,
- Cease coal generation at Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026, and
- Advance the addition of substantial renewable generation (1,200 MW by 2020).

Second, preserve regional system reliability. The preservation of system stability will be critical as we make the transition from coal energy to renewables, and we will preserve it by adding natural gas to our system and by continuing to operate our carbon-free nuclear fleet. We therefore propose to:

- Reaffirm our commitment to nuclear energy through the current licenses of our existing units,
- Add a combustion turbine (CT) in North Dakota by the end of 2025, and

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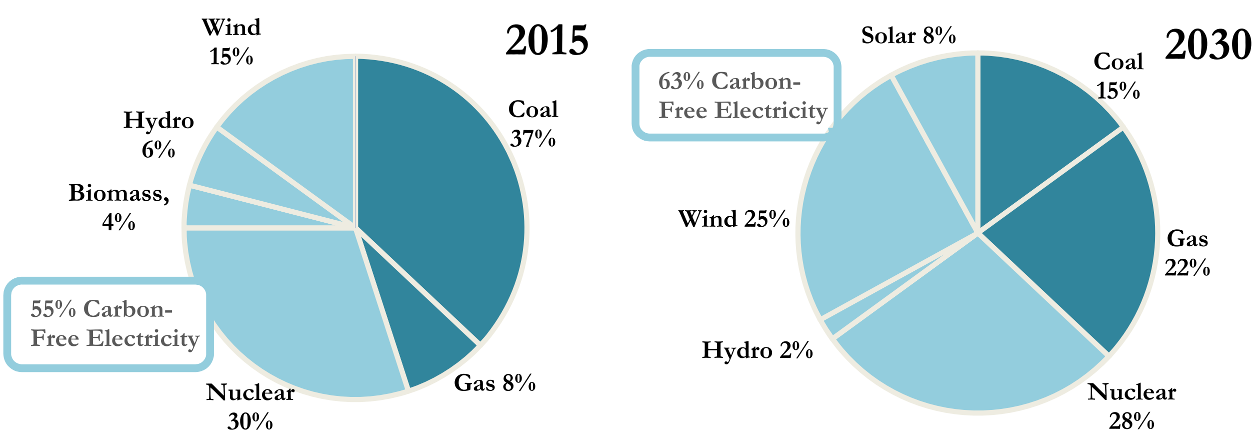
- Replace Sherco generation onsite with a combined cycle (CC) no later than 2026.

Third, pursue energy efficiency gains and grid modernization. We will continue our commitment to energy efficiency and new technologies and look to capitalize on these efforts rather than seeking to replace coal capacity megawatt for megawatt. We believe that modernizing the grid will further enable customer-driven solutions.

Fourth, ensure customer benefits. We will work with our state Commissions, the Minnesota Pollution Control Agency (MPCA) along with its counterpart environmental agencies in our other states, and our stakeholders to ensure our customers get the full benefit of our proposal. Specifically, we will work to maximize the benefits of complying with the Clean Power Plan (CPP) State Plans for our customers and communities.

In short, our vision for the future is cleaner at an affordable price. While our Current Preferred Plan includes slight variations in the timing and siting of our resource additions as compared to the proposal we outlined in our October 2 Reply, the resulting 2030 energy mix is the same. Likewise, the primary resource changes – ceasing coal operations at Sherco Units 1 and 2 and more than doubling the renewable resources on our system – remain unchanged. Figure 1 below provides a side-by-side comparison of our energy mix in 2015 and 2030.

Figure 1: 2015 Energy Mix Compared to Current Preferred Plan in 2030



Our Current Preferred Plan dramatically changes the NSP System energy mix at the end of the planning period. Coal *reduces* from 37 to 15 percent; natural gas *increases*

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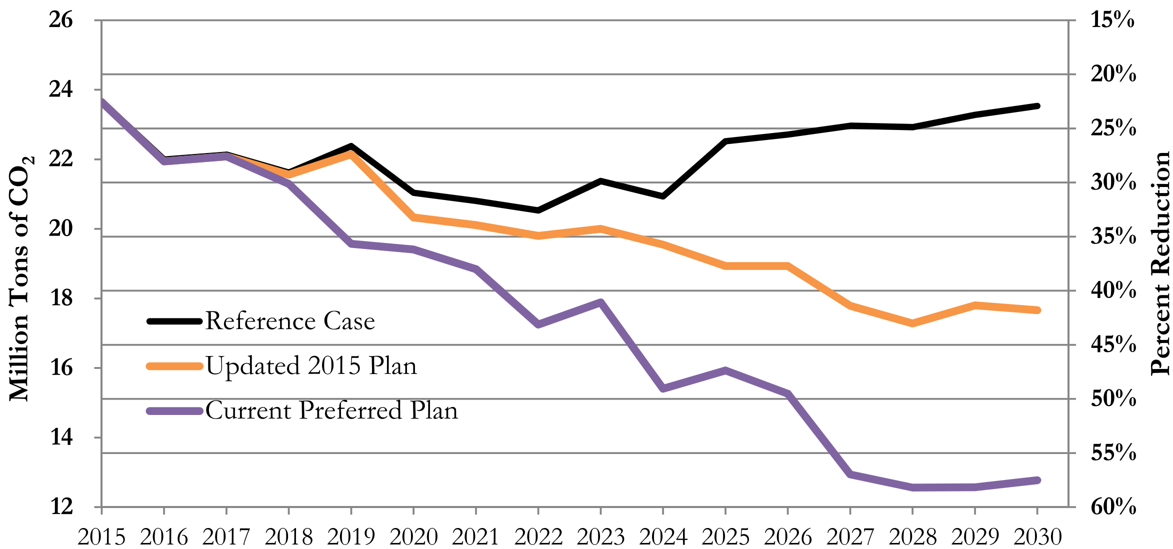
from 8 percent to 22 percent; solar, which makes up less than 1 percent of our energy mix in 2015, *increases* to 8 percent by 2030; wind *increases* from 15 to 25 percent; biomass and hydro *drop* to zero and two percent, respectively (due to contract expirations), while nuclear remains relatively constant at around 30 percent.

While our Updated 2015 Plan would have reduced our 2030 CO_2 emissions 40 percent from 2005 levels, our Current Preferred Plan puts us on an even greater CO_2 reduction trajectory. It will reduce CO_2 emissions by nearly 60 percent from 2005 levels by 2030, and it will move us significantly closer to achieving Minnesota's policy objective of an 80 percent reduction by 2050.

Figure 2: Projected Carbon Reduction from 2005 Levels



As discussed in greater detail below, we will achieve this dramatic reduction for just a fraction of a percent in incremental cost over our Updated 2015 Plan. Figure 2 below compares the projected CO_2 reduction of our Current Preferred Plan to our Updated 2015 Plan and the Reference Case.

It is also important to note that – given what we now know about the final CPP rules – the Reference Case would clearly not comply with the CO_2 reductions required of the Company under Minnesota's state plan to implement the CPP, nor may the Updated 2015 Plan. Further, we believe additional environmental compliance regulations will continue to place pressure on coal operations at Sherco. It is possible that installation of Selective Catalytic Reduction (SCR) equipment for tighter nitrogen oxide (NOx) control might be required near the end of the planning

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period.[4] We believe the actions we are proposing to take with our Current Preferred Plan positions us well to serve our customers into the future, and reduces the risk of potential future increased costs to maintain environmental compliance.

IV. MINIMUM SYSTEM NEEDS & EXPANSION PLAN

In this section, we discuss our strategy and proposal to address the future capacity deficit that results from our proposal to cease coal operations at Sherco Units 1 and 2, combined with a number of other large changes in our generating resources.

A. Load & Resources Analysis and Future Capacity Deficits

We provide in Table 1 below an updated Load and Resources (L&R) analysis that reflects our excess/deficit capacity position for the planning period, starting with the approved and existing resource additions reflected in our March 2015 Supplement. It also addresses the impact of the resource changes we propose as part of our Current Preferred Plan and summarizes our resulting capacity position through the planning period. Consistent with our January 2015 initial filing and all subsequent filings, we have used the same fall 2014 load forecast in this analysis, and maintained the same available resources to the Strategist model.

[4] In January 2016, the Eighth Circuit issued an opinion that upheld EPA's approval of the Minnesota regional haze plan, which did not require installation of SCRs on Sherco Units 1 and 2. The next regulatory developments that could include a requirement to install SCRs on these units will occur in the early 2020s, with installation potentially required in the late 2020s. The ozone standard, if made more stringent in 2020, might drive SCR installation in the 2027-2032 timeframe. The next round of regional haze planning is expected to occur in the early 2020s (EPA has announced plans to delay the 2018 deadline by 2-3 years), which could drive SCR installation in the late 2020s. We estimate that the capital cost for the installation of an SCR is approximately $250 million per unit in 2015 dollars.

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Table 1: Updated Load and Resources (MW UCAP[5])

	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
Existing/Approved Resources	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
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
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
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 (1)(3)	25	33	137	143	149	156	164	174	187	202	220	242	268	300	338
Aurora (3)	0	0	70	69	69	69	68	68	68	67	67	67	66	66	66
Community Solar Garden - Additions (2)(3)	20	36	53	72	94	103	103	102	102	101	101	100	100	99	98
Resources – Existing & Approved	9,866	9,942	10,122	10,597	10,562	10,821	10,833	10,806	10,427	9,282	8,758	8,479	8,177	8,186	8,218
Capacity Excess/ Deficit March 16, 2015 Filing	**260**	**251**	**358**	**779**	**719**	**958**	**909**	**887**	**490**	**-687**	**-1,282**	**-1,657**	**-2,136**	**-2,143**	**-2,212**

(1) Solar includes 2014 Solar RFP (Docket No. E002/M-14-162)

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

(3) Solar resources may be accredited up to 1 year earlier than forecasted based on changes to MISO's Business Practices for 2016/2017. This recent proposal has not been incorporated into the current L&R.

Current Preferred Plan – Existing Resource Changes	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sherco 2 Cease Coal Operation	0	0	0	0	0	0	0	-667	-667	-667	-667	-667	-667	-667	-667
Sherco 1 Cease Coal Operation	0	0	0	0	0	0	0	0	0	0	-694	-694	-694	-694	-694
Proposed Coal Changes	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-667**	**-667**	**-667**	**-1,361**	**-1,361**	**-1,361**	**-1,361**	**-1,361**
Capacity Excess/Deficit Jan 29, 2016	**260**	**251**	**358**	**779**	**719**	**958**	**909**	**220**	**-177**	**-1,354**	**-2,643**	**-3,017**	**-3,497**	**-3,503**	**-3,573**

The "Capacity Excess/Deficit March 16, 2015 Filing" line in Table 1 represents our updated capacity position before adding any of the resource changes proposed in our Current Preferred Plan. Consistent with our March 2015 Supplement and our October 2015 Reply, it shows we expect to have sufficient capacity to meet our customers' needs through 2024. However, beginning in 2025 our capacity position shifts from a surplus of nearly 500 MW to a deficit of over 2,200 MW by 2030. Much of this shift is due to the retirement of approximately 800 MW of peaking plants, as well as the expiration of nearly 1,700 MW of hydro and natural gas Power

5 MISO Unforced Capacity values, summer ratings.

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Purchase Agreements (PPAs) during the period, including the expiration of our existing 850 MW PPA with Manitoba Hydro in 2025.

The "Capacity Excess/Deficit Jan 29, 2016" line represents our position after applying the changes to existing resources that are part of our Current Preferred Plan.[6]

B. Current Preferred Plan Expansion Plan

Our Current Preferred Plan proposes to address the capacity deficit through a combination of renewable resource additions in the early years, and the addition of natural gas CT and CC units. In summary, our proposed resource additions are:

- 1,400 MW of large solar additions, including 400 MW by 2020,
- 1,800 MW of additional wind, including 800 MW by 2020,
- A 786 MW CC addition at the Sherco site in 2026 to replace the capacity of Sherco Unit 1 before it ceases operation,
- A 230 MW CT located in North Dakota by the end of 2025, and
- Over 1,800 MW of additional CT capacity.

The early renewable energy additions in our Current Preferred Plan will allow us to capitalize on favorable market pricing associated with the recently extended Federal ITC and PTC tax incentives, reducing the cost impacts of our Current Preferred Plan.

Our modeling results, described in more detail below, consistently show the addition of a CC in 2027.[7] We propose to locate the CC at Sherco because it will allow us to cost-effectively address the transmission issues identified by the Midcontinent Independent System Operator (MISO) Attachment Y2 Study, ensure the stability and reliability of our transmission system, mitigate impacts to the local community and our employees, and potentially provide improved access to natural gas supplies for communities in central Minnesota.

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[6] Unit retirements typically occur during a period of the three to nine months following the summer peak (months October-May). Commercial operation of replacement generation would commence between the months of October and March to maintain adequate capacity resources to meet MISO obligations.

[7] 2027 represents the year the CC resource is needed to address a capacity deficit; our Current Proposed Plan proposes that a replacement CC unit go in-service at Sherco such that there will be no gap in MISO capacity accreditation.

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In order to balance the perspectives of the stakeholders in the states we serve and maintain the benefits of an integrated system for all of our customers, we also propose to add a CT near our North Dakota load. This would address the reliability concerns of the North Dakota commission, while preserving the objective of both the North Dakota and Minnesota commissions for the Company to develop cost-effective generation proposals.

We show the resource additions we propose with our Current Preferred Plan in Table 2 below.

Table 2: Current Preferred Plan Expansion Plan[8] (MW ICAP[9])

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800
CT	-	-	-	-	-	-	-	-	-	-	460	690	230	230	-	230	1,840
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	230
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	786

Note: Resources are shown in their first full year of operation and will go into service the year prior.

We note that, with respect to solar, only the utility-scale resource additions proposed as part of our Current Preferred Plan are identified in this Expansion Plan. All small solar and previously-approved large solar resources are included as available resources in the L&R in Table 1 above. We discuss an update to our *small* solar forecast in Attachment B to this Supplement. To the extent small-scale solar additions out- or under-pace our updated small solar forecast, we will make corresponding adjustments to our large solar acquisition plan.

For reference, we provide updated Renewable Energy Standard and Solar Energy Standard compliance information, as well as the Expansion Plans for the Reference Case and Updated 2015 Plan in Attachment C.

V. RESOURCE PLANNING ANALYSIS

We provide as Attachment B details regarding our revised modeling assumptions, the scenarios and sensitivities analyzed, potential alternatives, an economic analysis,

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[8] We clarify that we do not show the small solar additions, the 187 MW Solar RFP, or the competitive acquisition process resources in our Expansion Plan. These are included as existing/approved resources in the Updated L&R (Table 1).
[9] MISO Installed Capacity values.

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a discussion on our treatment of dump energy, and a methodology for our long-term rate impact projections – which we also summarize below.

We analyzed and compared five key scenarios in our analysis. We summarize the assumptions underlying these scenarios in Table 3 below.

Table 3: Summary of Scenarios Analyzed

Scenario Name	Description
Current Preferred Plan	• Ceases operation of a total of 1,400 MW of capacity and associated energy at Sherco Unit 2 in 2023 and Unit 1 in 2026 • Adds 1,800 MW of wind • Adds 1,400 MW of large solar • Includes 700 MW of small solar • All renewable costs updated for Federal ITC/PTC extension • Includes goal of 50 percent ownership of renewables • Adds Company-owned Fargo CT by 2025 and Sherco CC in 2027
Current Preferred Plan – All Generics	Same resource changes as Current Preferred Plan, with all generic thermal replacements
Reference Case	• Continues operation of Sherco Units 1 and 2 through the end of the planning period • Adds 400 MW of wind • Includes 400 MW of small solar additions • Includes 287 MW of large solar additions
Updated 2015 Plan	• Continues operation of Sherco Units 1 and 2 through the planning period • Adds 1,800 MW of wind • Adds 1,400 MW of large solar • Includes 700 MW of small solar • Updated for Federal ITC/PTC extension
North Dakota Plan	No additional renewables beyond currently committed 750 MW of wind; no assumptions changes.

We additionally considered the following alternative scenarios, which we discuss in Attachment B:

- A scenario that converts a Sherco Unit to a Gas Boiler, and
- A scenario that relies only on renewables.

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We also discuss Demand Response, Distributed Energy Resources, and Grid Modernization as Alternative Resources in Attachment F.

We evaluate these scenarios holistically by analyzing their environmental performance, strategic flexibility, and cost using a "Run Key" to summarize and compare key Strategist modeling metrics. The Run Key below includes the results of the Present Value Revenue Requirements (PVRR) and Present Value of Societal Costs (PVSC) analysis for each of our key scenarios to provide a reference point, but it also identifies key policy outcome metrics such as the reduction in CO_2 emissions from 2005 levels and the amount of renewable energy added to the NSP System under each scenario. We note that the PVRR and PVSC results are the result of the Strategist model, which extends beyond the planning period to 2053.

Table 4: Run Key[10]

	PVSC Results ($M)	PVRR Results ($M)	2030 Coal Gen vs. Ref Case	2030 Gas Burn (Bcf)	2030 Percent CO_2 Reduction	Total Expansion Plan Renewable Additions (MW)	CPP Compliant?
Current Preferred Plan	$51,293	$45,606	-59%	83	58%	3,200	Yes
Current Preferred Plan, All Generics	$51,280	$45,582	-59%	84	57%	3,200	Yes
Updated 2015 Plan	$51,458	$45,302	-16%	32	42%	3,200	Uncertain
Reference Case	$52,422	$45,605	-	58	23%	400	No
North Dakota Plan	$52,620	$45,473	+3%	68	19%	0	No

The comprehensive Run Key analysis shows that our Current Preferred Plan has the strongest performance in terms of CO_2 reductions and renewable energy additions to the NSP System. The amount of renewable energy additions in our Updated 2015 Plan and Current Preferred Plans are consistent, but the timing and ownership assumptions have shifted. Our Current Preferred Plan continues to provide the best value for our customers – achieving a balance between multiple objectives including reasonable costs, dramatic emissions reductions, anticipated compliance with the CPP, and sustained reliability on our system.

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[10] In this Run Key Table, the PVRR Results, change in coal generation in 2030 as compared to the Reference Case (2030 Coal Gen vs. Ref Case), amount of gas burned at our plants in 2030 in Billions of cubic feet (2030 Gas Burn (Bcf)), and the percent reduction of CO_2 from 2005 levels (2030 Percent CO_2 Reduction) are all considered under a cost sensitivity that excludes regulatory costs and CO_2 externalities in the dispatch (Sensitivity T, explained in detail in Attachment B). Under this sensitivity, there will be a tendency to overestimate CO_2 emissions, as coal would be 'priced' at a lower cost and the likelihood of dispatching the resource more frequently would therefore be increased.

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A. Modeling Approach

This resource planning process begins the transformation of our generating fleet and signals a step change. It is additionally important to the states in the Upper Midwest Region in terms of alignment and compliance with the requirements of the CPP.

Over the last 20 years, resource plans have traditionally centered on meeting the needs of a growing system, or replacing smaller generators that have reached the end of their lives. In this Resource Plan, we are proposing to cease operation of 1,400 MW of coal generation at Sherco Units 1 and 2, which represents over 30 percent of our baseload generating capacity within the short 2023-2026 timeframe. Because these resources are concentrated in a single geographic area and proximate to other baseload generation, it is important to consider the location of replacement generation. This is a departure from traditional resource planning. In this instance however, the location of new or replacement generation requires additional consideration due to the potential impact to the system of removing such large important assets.

In considering the replacement of key components of an existing system, such as Sherco Units 1 and 2, the analysis must take into account a number of additional considerations that cannot always be captured in economic modeling or analysis terms. These other considerations are both technical and policy-based and include the security and reliability of the combined operation of the generation fleet and the transmission system.

We therefore conducted both traditional "generic" and location-specific Strategist modeling to inform the Current Preferred Plan we propose. We provide an optimized capacity Expansion Plan that considered only generic capacity alternatives as Table 5 below.

Table 5: Generic Unit Expansion Plan (MW ICAP)

Current Preferred Plan - All Generic	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800
CT	-	-	-	-	-	-	-	-	-	-	690	690	230	460	-	-	2,070
CC	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	778

These analyses resulted in the same conclusions in terms of the size and type of expansion resources and nearly identical in their timing. Both the site-specific and

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generic modeling shows a need for CT capacity in the 2025 timeframe and a CC addition in 2027.[11]

However, as part of the determination to cease coal operations at Sherco Units 1 and 2, we believe it is important and appropriate to also consider the impacts to the transmission system, the local community, state and federal policies, customer and community preferences and cost impacts. We have undertaken numerous studies to better understand these and other implications of our Current Preferred Plan. We believe our plan addresses these issues through our proposal to locate a CT in North Dakota by the end of 2025 and to locate a CC at the Sherco site in 2026 in order meet the capacity deficit resulting from ceasing coal operations at the second Unit.

Table 6 below outlines our capacity surplus/deficit position after applying the proposed resource additions of our Current Preferred Plan.

Table 6: Capacity Position with Current Preferred Plan Expansion Plan (MW UCAP)

Current Preferred Plan Proposed Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Large Solar	0	0	0	0	0	209	261	314	418	471	523	523	732	732	732
Wind	0	0	0	0	0	118	178	178	178	266	266	266	266	266	266
North Dakota CT	0	0	0	0	0	0	0	0	0	219	219	219	219	219	219
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	763	763	763	763
CT	0	0	0	0	0	0	0	0	0	439	1,097	1,316	1,535	1,535	1,755
Total Plan Additions	**0**	**0**	**0**	**0**	**0**	**328**	**439**	**491**	**596**	**1,365**	**2,105**	**3,087**	**3,516**	**3,516**	**3,735**
Revised Proposal Capacity Excess/ Deficit	**260**	**251**	**358**	**779**	**719**	**1,286**	**1,348**	**1,379**	**419**	**11**	**156**	**70**	**19**	**12**	**162**

As shown above, our resulting capacity position is a surplus through the planning period. In 2025 and beyond, our position reflects the expiration of significant capacity resource PPAs and peaking retirements we discussed above, resulting in our more narrow capacity position in the out-years of the planning period. Because

[11] The Department noted in its November 6, 2015 Comments that the Updated 2015 Plan we filed in our initial January 2015 filing and March 2015 Supplement did not include the addition of a CC resource prior to 2030. We note that at the time of those filings, we had not proposed to cease operation of any major generating units in the planning period like we now propose with Sherco Units 1 and 2. Ceasing coal operations of Sherco Units 1 and 2 results in the loss of nearly 1,400 MW of high-capacity-factor generation, which drives our need to add a CC resource prior to 2030. The model selects a natural gas CC unit in 2027 as a cost-effective resource addition to fill this gap. In addition to the favorable economics of adding a CC instead of a CT, at the time the second Sherco Unit ceases coal operation, we must also consider the technical system benefits the Sherco Units provide through their spinning mass to help maintain system reliability. We would not expect a simple-cycle CT to be online very often – nor would that be cost-effective as compared to a CC.

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these changes will occur in the out-years, we can continue to monitor our position over time and through the course of upcoming resource planning cycles. Addressing any potential necessary resource additions to meet capacity needs in the mid to late 2020s will be analyzed in our next Resource Plan filing, which we expect to occur by 2018.

B. Locational Analysis

As we have discussed, Resource Plans typically do not analyze location-specific alternatives. However, we believe that our Current Preferred Plan – as well as state and federal policies – present unique challenges that are not easily addressed through a traditional resource planning framework. Sherco Units 1 and 2 are critical components of our energy supply and the Upper Midwest grid. In addition to the energy and capacity they provide to customers, the sheer mass and operating characteristics of these Units provide important system benefits that impact customer reliability. For these reasons, and because the maintenance of system reliability is critical to serving the public interest, a location-specific analysis is essential. With respect to the CT needed in 2025, our North Dakota regulators have stated a preference, and the Company has agreed, to have dispatchable generation located close to our largest load centers in North Dakota, which we discuss in part 3 below.

In order to examine various aspects of the technical and policy-based issues associated with Sherco Units 1 and 2, we undertook several studies to understand the impacts of ceasing coal operations at Sherco Units 1 and 2. The studies we conducted to examine the implications of potentially ceasing coal operations at Sherco Units 1 and 2 are as follows: (1) a MISO Attachment Y2 Study, which assessed grid implications if Units were no longer operating; (2) an Xcel Energy Transmission Reliability Study, which assessed grid implications of replacing all or a portion of the Units' capacity at other locations on the NSP System; (3) a Black Start Plan Analysis that assessed the implications associated with altering our system restoration path and would be necessary because the Units currently play an essential role in the event of a major system outage; and (4) a socioeconomic analysis conducted by the Leeds School of Business at the University of Colorado Boulder and the Labovitz School of Business and Economics at the University of Minnesota Duluth.

We discuss each of these location-specific resources below.

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1. *On-Site Combined Cycle Unit at Sherco*

First, we are proposing to construct a 786 MW (ICAP) natural gas CC onsite at the current Sherco site. Because we are not replacing all of the MWs that result from ceasing coal operations at Units 1 and 2 with the CC unit, there will be additional interconnection injection capabilities at the site, which we are proposing to partially utilize by also constructing photovoltaic (PV) solar generation on existing property.[12]

As outlined in Attachment B, our updated modeling for this Supplement includes several options for a CC: (1) at the site of the current Sherco 1 and 2 Units, (2) at a generic brownfield site, and (3) at a generic greenfield site. We developed the option of onsite replacement to incorporate into our Strategist modeling an economic analysis of locating generation at the Sherco site. We believe there are significant benefits associated with siting the CC at the Sherco site, which we discuss below.

a. Benefits of Onsite Generation at Sherco

There are number of benefits to locating a replacement CC at the Sherco site. Importantly, our Strategist demonstrates that the addition of a CC unit onsite at Sherco is part of a least-cost capacity expansion plan. However, not all relevant factors are easily converted to an economic basis for inclusion in Strategist. For instance, there are benefits to using existing infrastructure and an existing brownfield site that do not easily reduce to economic terms, including the fact that the transmission grid has been studied, designed, engineered and operated for decades to provide a high degree of reliability and resiliency for customers by incorporating significant generation injection at the Sherco site. Similarly, it is important to consider that our host community of Becker, Minnesota and the greater Sherburne County area has come to depend on local employment opportunities, property taxes, and other economic benefits associated with the existing units. We discuss these factors below.

Use of Existing Infrastructure. As an existing brownfield generation site, the Sherco site offers a number of advantages over new greenfield sites, both in terms of operations and cost. For example, we can use our existing interconnection rights and existing substation and transmission outlet capacity once Units 1 and 2 cease

[12] We have identified two areas on the existing Sherco site for solar development. One location would be atop the closed and capped ash ponds 1 and 2 and the second would be on open land on the north side of the Mississippi River between the Sherco plant and the Monticello plant.

coal operations. The existing Sherco site also comprises sufficient available land to site a CC unit and is already permitted for a large industrial generating facility. Further, existing water and wastewater treatment facilities can support the proposed CC unit, and existing facility staff, administration, warehousing, and maintenance facilities can likewise be utilized. Finally, the site's water allocation is sufficient for cooling approximately 2,300 MW of generation (the current combined installed capacity of Sherco Units 1, 2 and 3), which means that once Units 1 and 2 cease coal operations, an allocation equivalent to approximately 1,400 MW will become available. Consequently, portions of the Unit 2 cooling system can be reused by the new CC facility, allowing the replacement CC at the Sherco site to be wet-cooled, improving both performance and cost.

The System is Designed to Reliably Operate with Significant Generation Injection at Sherco. From the technical studies conducted by MISO and the Company we concluded that we can avoid anticipated impacts on the electric transmission system and related costs by replacing generation at Sherco. In contrast, siting replacement thermal generation at other locations on the NSP System have disadvantages compared to siting a CC at Sherco, including a significant level of uncertainty with regard to final costs and performance. The *Xcel Energy Transmission Reliability Study* confirmed that the existing transmission system with significant generation injection at Sherco works well, and plays a significant role in providing reliable service for NSP System customers and other customers in our portion of the MISO region. It also concluded that there are transmission upgrade costs and other trade-offs associated with replacing Sherco Units 1 and 2 at an alternative location, such as increased energy losses the farther the replacement generation is located from the Twin Cities load center.

Unlike an onsite CC that will have injection capability and interconnection rights, replacement generation at other locations will be subject to the MISO generator interconnection process, and may incur additional network upgrade costs beyond those we have identified. The MISO interconnection queue has changed significantly since these technical studies were initiated in early 2015. Since March 2015, requests to add nearly 10,000 MW of wind have entered the queue in the Iowa, Minnesota, North Dakota, and South Dakota area.[13] Nearly 70 percent, or 7,000 MW have paid all required study deposits and achieved milestones, qualifying them to participate in MISO's upcoming interconnection studies. This significant

[13] MISO Generator Interconnection Queue is located at: https://www.misoenergy.org/Planning/GeneratorInterconnection/Pages/InterconnectionQueue.aspx.

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number of projects that have entered MISO's interconnection queue creates uncertainty with respect to the identified transmission impacts and associated interconnection costs. Replacement generation at the Sherco site, as we have proposed, has the added benefit of not being impacted by this uncertainty.

Locating a CC at the Sherco Site Avoids Significant Transmission Costs. Our technical studies each identified costs associated with siting replacement generation at locations other than Sherco. We summarize the study results below and provide a full summary of the studies and our conclusions as Attachment D.

MISO Y2 Study. MISO concluded that retirement of Sherco Unit 1 and Sherco Unit 2 would result in violations of applicable planning criteria that would require transmission upgrades and the need for Units to be designated as System Support Resources (SSR). Assuming a future Attachment Y study would have similar results, MISO would require that the identified violations be mitigated to its satisfaction prior to retirement of Sherco Units 1 and 2, if replacement generation is not located at Sherco. Specifically, the MISO Y2 study identified significant thermal and voltage violations in the Twin Cities if Sherco Units 1 and 2 are retired. The voltage violations impact our Monticello Nuclear Plant's operation and Nuclear Regulatory Commission (NRC) requirements. Both the thermal and voltage violations would need to be addressed through transmission investment in the Sherco area, regardless of the location of any replacement generation at an alternative site before the units could cease operation. Additional transmission upgrades that may be necessary due to the location of replacement generation, were not within the scope of the MISO Y2 study, but were studied in the Xcel Energy Transmission Reliability Study we discuss below. We provide this study report as Attachment D1.

Xcel Energy Transmission Reliability Study. Our study, conducted in conjunction with Siemens Power Technologies International, involved a full thermal analysis, full voltage analysis, and transient stability analysis. As noted above, it confirmed that the existing transmission system with significant generation injection at Sherco works well, and that there are transmission upgrade costs and other trade-offs associated with replacing Sherco Units 1 and 2 at an alternative location. We provide these study reports as Attachments D2 and D3.

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Black Start Plan Analysis. Our analysis of our current Black Start Plan examined impacts if our current Sherco Units 1 and 2 target units cease coal operations.[14] Our analysis concluded that our proposal to construct a natural gas CC unit at the Sherco site would provide for use of the current and most efficient restoration path. Altering the restoration path away from the Sherco site will require the addition of various equipment and/or facilities and results in a longer restoration period, which is of greatest concern in winter/cold months. We have included the approximate costs of altering our restoration path as part of the costs associated with siting the 2027 CC at alternative locations.

If replacement generation is not sited at Sherco, we must mitigate the reliability issues our technical studies identified. For example, the Monticello Plant cannot operate if its voltage is outside the permissible range. As discussed further in Attachment D, we have determined that the best option to address these issues is to convert Sherco Unit 1 or Unit 2 to a Synchronous Condenser (SC). Importantly, SCs provide not only the required continuous range of voltage support, but are also a rotating mass that helps hold the grid electrically together following a disturbance such as a major fault. These additional costs stem from transmission upgrades and the need for additional equipment onsite at Sherco and other locations on the NSP System. We refer to these costs as "leave-behind" costs, which are therefore appropriately added to the cost of any combined cycle generator at an alternative location. The total leave-behind costs are shown below in Table 7.

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[14] A Black Start Plan specifies the process of restoring the grid to full operation without relying on the external transmission network following a full or partial black out. Black Start Plans are required by the North American Electric Reliability Corporation (NERC), developed in concert with neighboring utilities, and are subject to review and approval by MISO.

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Table 7: Leave-Behind Costs – PVRR
($Millions – 2015)

Cost Components	PVRR
	[TRADE SECRET BEGINS…
Installation of Synchronous Condenser	
O&M for Synchronous Condenser	
Upgrade Brainerd - Riverton 115 kV Line	
Rebuild Helena - Scott County 345 kV Line	
Installation of Additional Capacitors	
New Blackstart Path	
	…TRADE SECRET END]
Total	**$150**

Retiring Sherco Units 1 and 2 would have negative impacts on employment, GDP, and disposable personal income in Sherburne County. We understand the Commission has previously expressed interest in understanding the socioeconomic impacts on the Becker area, so therefore commissioned a socioeconomic study. We summarize the study below and provide a full summary and the study itself as Attachments G and G1, respectively. This Study assessed impacts on employment, Gross Domestic Product (GDP), and disposable personal income on the locations impacted by a change in operating expenditures, capital expenditures, property taxes, and electricity rates resulting from Unit retirement and replacement at an alternative location. The scenarios analyzed in the Study, included various potential Unit retirement dates and a scenario that included the replacement of the two Sherco Units with one CC at the Sherco site and one CC located in Dakota County. The Study found that all early retirement scenarios, when compared to a baseline where the Units continued operations through the planning period, result in moderately slower growth in the Minnesota economy. The closure of the Units showed negative impacts on employment, GDP, and disposable personal income in Sherburne County. However, if the generation is replaced elsewhere in Minnesota, those impacts are partially offset by positive economic impacts in the replacement location – mitigating on an overall state-level, the negative impacts. While the Study did not model a scenario that directly reflects our Current Preferred Plan, our proposed 2023 and 2026 dates fall within the range of scenarios analyzed.

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As we stated in our October 2, 2015 Reply, ceasing coal operations at Sherco Units 1 and 2 will impact our employees and their families, the City of Becker and surrounding area, and Liberty Paper, which relies on steam from the Units for its operations. Charting a path certain for these stakeholders particularly, will provide an 8-10 year transition period, and with our proposal to site replacement generation onsite, will promote economic development, and reaffirm our commitment to central Minnesota. We are committed to mitigating impacts on our employees by working closely with our International Brotherhood of Electrical Workers union local to successfully manage the transition. Finally, our proposed onsite CC will provide additional options to continue to supply steam to Liberty Paper, who is a valued Xcel Energy customer, an important employer in the Becker area, and a critical part of Minnesota's recycling industry.

b. Costs of Onsite CC

Generating Equipment. We developed the costs for the onsite CC generation based on the installation of a 2x1 CC wet-cooled facility in 2026, which would begin commercial operation prior to the second Sherco Unit ceasing coal operations. The summer-rated capacity of the CC facility would be approximately 763 MW UCAP (786 MW ICAP). We developed our initial capital cost estimates for the onsite Sherco CC by adjusting the cost of the generic CC used in the modeling throughout this proceeding for the site-specific benefits associated with utilizing existing infrastructure. Because of the site's available water allocation, the replacement CC at the Sherco site is to be wet-cooled, improving both performance and cost. We expect the initial capital cost of the generic CC to be approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** higher than our proposed onsite CC at Sherco.[15]

Because we have not obtained formal estimates for the turbine equipment or performed detailed engineering, we have developed delta cost estimates in order to compare the unique attributes of locating a CC onsite and at alternative locations. The ultimate project pricing will vary based on the final design definition, equipment price negotiations, contractual commercial terms, and other factors.

[15] 2015 dollars on a PVRR basis. We use the same Fixed Operating and Maintenance (Fixed O&M) costs and on-going capital costs as the generic CC alternative.

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Natural Gas Infrastructure. Our proposed CC unit at Sherco will be fueled entirely by natural gas. Even though the community of Becker enjoys the benefits of heating their homes and commercial businesses with natural gas from Xcel Energy, there is not currently adequate pressure and capacity with the existing natural gas infrastructure to serve a new CC unit.

Therefore we performed a high-level cost analysis of bringing new natural gas infrastructure to serve the proposed CC unit at Sherco, so as to estimate a gas demand charge, which we estimate to be approximately **[TRADE SECRET BEGINS…**
… TRADE SECRET ENDS] to the Sherco site. We based this estimate on our experience in designing, engineering, and constructing competitive natural gas infrastructure, which we do through the use of a competitive bidding process for each component or phase of the construction process. We also benchmarked the costs of some of our past significant, similar construction projects within the industry to ensure that our estimates are in-line with other contractors. We will leverage our knowledge, expertise, and competitive advantage to minimize costs for our customers. We note that we are also assessing opportunities arising from the new natural gas infrastructure that may afford numerous adjacent Minnesota communities along the proposed route greater access to a natural gas supply.

In determining the cost to construct the natural gas infrastructure, there are two primary aspects to consider: (1) the cost of the facilities from the source of supply to the new market (in this case, Sherco); and (2) the costs from the source of the supply, to ensure the new infrastructure has adequate pressure and capacity. We evaluated several alternatives to determine the best way to source the new supply to Sherco.

The associated capital cost estimates incorporated into our modeling are indicative. The cost estimates we provide for this analysis are based on current system constraints and associated capital construction project costs required to alleviate those constraints, which are subject to change. We believe however, they are reasonable and appropriate for planning purposes.

Transmission Infrastructure. As discussed above, because the new CC unit can use existing transmission interconnection rights, there will not be any associated network upgrade costs. Generators located at other locations would have to go through the MISO generator interconnection process in order to obtain

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interconnection rights, and may additionally incur transmission upgrade costs. We estimate onsite substation modifications to cost approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**. We note that we are proposing a 786 MW CC unit, which is below the current 1,400 MW capacity and associated energy output of Sherco Units 1 and 2. We also intend to locate a portion of the proposed solar resource additions at the Sherco site.

We outline the cost deltas from a generic CC on a PVRR basis below.[16] This approach allows us to show the site-specific costs associated with locating a CC at the Sherco site and to compare the site-specific costs of onsite replacement to alternative site locations.

Table 8: Site-Specific Cost Comparison – Onsite CC Replacement ($Millions – 2015 dollars)

[TRADE SECRET BEGINS…

PVRR Delta from Generic Unit	
Site Specific PVRR Costs	
Transmission Facilities[17]	
Gas Demand Charge	
…TRADE SECRET ENDS]	
Total	***$155***

2. *Alternatives to Retirement and Onsite Replacement*

We considered several alternatives to our proposed partial replacement of the Sherco Units with an onsite CC generating unit. In addition to examining another brownfield site and a greenfield site, we explored alternatives such as all renewables and alternative resource such as Distributed Energy Resources, Demand Response, and grid efficiencies. We discuss the brownfield and greenfield alternatives below and the renewables and alternative resources in Attachments B and F, respectively.

[16] All costs have been discounted to 2015 dollars. Actual costs will be influenced by the year in which they are incurred. Therefore, in order to compare these estimates with future expenditures, these estimates must be escalated.

[17] The substation modification costs noted above are included in the delta from the generic unit.

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Our Current Preferred Plan does not propose to replace all of the Sherco Units 1 and 2 capacity with gas-fired generation. As explained in our October Reply, we are committed to reducing the CO_2 emissions of the NSP System and advancing the acquisition of significant levels of renewable generation. Thus, we plan to acquire significant amounts of wind and solar resources to help meet our future energy and capacity needs. Below we discuss alternatives to replacing the Sherco Units with an onsite CC, in conjunction with additional renewable generation.

a. Offsite Brownfield CC

The Offsite Brownfield CC alternative included in our updated modeling is based on representative costs associated with locating a CC at the existing Black Dog site in Burnsville, Minnesota. Black Dog coal-fired Units 3 and 4 were suspended in early 2015, and the coal and ash storage and handling areas are currently being remediated and closed. When this work is complete, there will be sufficient land area protected from the 100-year flood plain to construct a 2x1 CC facility and 345 kV switchyard. The Twin Cities 345 kV ring is nearby – approximately just one-half mile from the plant site – and could be used as the transmission outlet from the new facility, making this site an appropriate proxy for an off-site brownfield CC.

Current information indicates that a new 345 kV substation would be required to accommodate the installation of this CC Unit. However, as noted above, additional transmission upgrade and interconnection costs could be incurred through the MISO generator interconnection process. Gas costs for this facility are based on anticipated demand charges for use of the Northern Natural Gas (NNG) system. The site has significant water allocations and would be able to support a wet-cooled CC facility through conversion of the existing Black Dog facility from a once-through cooling system to a cooling tower system.

Similar to the onsite Sherco alternative, locating generation on a brownfield site results in savings related to transmission upgrades, gas infrastructure, and other existing infrastructure such as land, access to water supplies, and existing maintenance facilities and facility staff.[18] As we did for the onsite CC alternative, we have adjusted the generic CC cost to incorporate the advantages of a brownfield location. However, this analysis must include the costs to mitigate the loss of

[18] While the Brownfield site is located near existing transmission facilities, the availability of interconnection capacity is uncertain until the MISO interconnection process is complete.

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generation at the Sherco site. Table 9 below summarizes the cost deltas from a Generic CC in the representative Offsite Brownfield CC alternative:

Table 9: Site-Specific Cost Comparison – Offsite Brownfield Alternative ($Millions – 2015 dollars)

	Brownfield Alternative	Sherco CC
	[TRADE SECRET BEGINS…	
PVRR Delta from Generic Unit		
Site Specific PVRR Costs		
Leave-Behind Costs		
345 kV Interconnection Facilities		
Annual Gas Demand Charge		
		…TRADE SECRET ENDS]
Total	***$221***	***$155***
PVRR Delta from Sherco Site	**$66**	

The Offsite Brownfield CC results in approximately $66 million in additional costs as compared to siting the CC at Sherco. In addition, locating the replacement CC offsite results in greater risk of additional transmission expense and reliability impacts, and does not consider the important economic benefits of replacing generation at the Sherco site, nor the potential of expanding access to natural gas supplies to residents of central Minnesota.

b. Offsite Greenfield CC

We also included an Offsite Greenfield CC alternative in our updated modeling. The Greenfield site is based on a location in Western Minnesota near existing transmission and interstate natural gas lines. Water resources are limited, and it is expected that such a facility would have to be dry-cooled to minimize water use. We have evaluated the costs for transmission interconnection and upgrades and natural gas infrastructure, and included those costs in our analysis. As noted above, additional transmission upgrade and interconnection costs could be incurred through the MISO generator interconnection process. Gas costs for this facility assume construction of new infrastructure. Table 10 below summarizes the costs included in the representative Offsite Greenfield alternative:

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Table 10: Site-Specific Cost Comparison – Offsite Greenfield Alternative ($Millions – 2015 dollars)

	Greenfield Alternative	Sherco CC
	[TRADE SECRET BEGINS…	
PVRR Delta from Generic Unit		
Site Specific PVRR Costs		
Leave-Behind Costs		
345 kV Interconnection Facilities		
Annual Gas Demand Charge		
		…TRADE SECRET ENDS]
Total	***$172***	***$155***
PVRR Delta from Sherco Site	**$17**	

The Offsite Greenfield CC results in approximately $17 million in additional costs as compared to siting the CC at Sherco. The Offsite Greenfield alternative is a CC located along the Brookings 345 kV line, so will use available transmission outlet capability that could otherwise be used for renewables in the wind-rich western and southwestern areas of Minnesota, which may increase transmission upgrade costs for those types of facilities during the planning period. These costs are difficult to quantify, but could be significant. As with the offsite brownfield alternative, locating the replacement CC offsite results in greater risk of additional transmission expense and reliability impacts, and does not consider the important economic benefits of replacing generation at the Sherco site, nor the potential of expanding access to natural gas supplies to residents of central Minnesota.

c. Conclusion

The addition of a CC at the Sherco site is a critical part of our proposal to cease coal operations of Sherco Units 1 and 2 and ensure reliability at a reasonable cost to ratepayers. By locating a CC at Sherco, we eliminate the need to address the issues identified in the MISO Y2 Study, avoid the costs associated with locating the CC offsite, support economic development in the Becker area, and mitigate reliability risks and implications stemming from the shutdown of two of the largest baseload generating units in the Upper Midwest. Our Strategist analysis, transmission studies, and socioeconomic studies support this proposal, and we believe it best advances the interest of our customers, as well as the Becker economy and our employees.

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3. *North Dakota Combustion Turbine*

a. Policy Considerations

Our regulators in North Dakota have stated that they believe it would be in the best interest of our customers to have cost-effective, dispatchable generation located in North Dakota and close to major load centers in that state. In an effort to balance the interests of the states that we serve and to maintain the benefits of an integrated system for all of our customers, the Company set out to find CT options that address the reliability concerns of the North Dakota commission, while preserving the Company's desire to develop cost-effective generation alternatives. To that end, we embarked on a review of possible generation sites located reasonably close to Company load centers in North Dakota that could also satisfy traditional resource planning criteria. We discuss the results of that review below.

b. Alternative Sites

In our review, we identified two potential areas where a CT could be located that satisfies the common desires of Minnesota and North Dakota commissions for a selection of a cost-competitive and reliable generation resource. The two locations include an area west of Fargo (Fargo CT) and a location in the south-central portion of North Dakota (South Central CT). These two sites appear to satisfy the traditional resource planning criteria, while also aligning policies regarding energy security, reliability, and energy policy objectives.

Recognizing that the Company is the largest utility in North Dakota, and that the Company does not yet have any dispatchable generation (either owned or in the form of a PPA) in that state, we decided to start the search for potential generation sites with a focus on North Dakota. While a formal project development and engineering estimate has yet to begin, it appears that both sites have adequate access to natural gas supplies and transmission injection capacity as well as available land and workforce.[19]

We also looked at alternative locations in Minnesota and Wisconsin. The potential site in Minnesota included the development of a second CT at our existing Black

[19] While generators at both sites would be required to go through the MISO generation interconnection process, a CT has an advantage over a CC as it is a peaking resource and will only be studied on-peak where we believe significantly more transmission capacity exists in the locations considered for the alternative CTs.

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Dog site. Consistent with the Black Dog 6 CT that was recently approved by the Minnesota and North Dakota commissions, the Black Dog 7 site takes advantage of an already owned brownfield location with access to transmission and an existing workforce.

While we also identified a possible site for a CT in Wisconsin, we did not perform any additional development work on that site at this time due to the need for more robust transmission studies. While all of the sites in Minnesota also appear to satisfy traditional resource planning criteria, they obviously do not address the concerns about the lack of dispatchable generation near the Company's North Dakota load.

Table 11 below contains a summary table of the key resource planning characteristics of the three locations investigated by the Company.

Table 11: Summary of CT Alternatives

	Fargo	**South Central**	**Black Dog 7**
Generator	Generic 230 MW Dual-Fuel CT[20]	Generic 230 MW Gas-Fired CT	Generic 230 MW Gas-Fired CT
Gas Supply	Lateral Gas Pipeline	Lateral Gas Pipeline	Demand Charges on NNG
Transmission	345 kV Interconnection Facilities	345 kV Interconnection Facilities and 230 kV Line Upgrades	345 kV Interconnection Facilities

Since both the Minnesota and North Dakota commissions have a keen interest in determining if the proposed CT alternatives are cost-effective and reliable when compared with other alternatives, we have performed an initial analysis of the three sites identified by the Company. While we have not obtained formal estimates on the turbine equipment or performed detailed engineering on the projects, as with the analysis of CC site alternatives above, we developed delta cost estimates from the generic CT unit used in the modeling. The deltas show the site-specific cost differences for each location based on the unique factors of the generator site, including transmission access, gas supply costs, and operation and maintenance costs. We summarize this cost comparison in Table 12 below.

[20] We are proposing oil back-up at the Fargo site to allow for the unit to have firm accreditation year-round, similar to the Company's Angus Anson Units 2 and 3 in South Dakota.

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Table 12: Site-Specific Cost Comparison – CT Alternatives
($Millions – 2015 dollars)

	Fargo	South Central	Black Dog 7
	[TRADE SECRET BEGINS…		
PVRR Delta from Generic Unit			
Site-Specific PVRR Costs			
Transmission			
Annual Gas Demand Charge			
			…TRADE SECRET ENDS]
Total	***$79***	***$106***	***$85***
PVRR Delta from Fargo Site		**$27**	**$6**

This preliminary cost analysis shows that the Fargo CT site is cost competitive to the Black Dog 7 CT project, while the South Central North Dakota CT site is somewhat higher in cost.

4. Conclusion

The impact to our customers, reliability, the transmission system, the local community, and state and federal policies are all appropriately considered as part of the determination to cease coal operations at Sherco Units 1 and 2. We have undertaken numerous studies to better understand the implications of our Sherco proposal and believe our Current Preferred Plan addresses these issues in a cost-effective manner. For these reasons, we believe our location-specific expansion plan is in the public interest.

C. Ownership of New Resources

We propose to own the Sherco and North Dakota natural gas plants, along with a portion of the renewable generation additions contemplated by our Expansion Plan. Our ownership of these assets is a critical component of our vision, as it will result in a balanced generation portfolio that will minimize customer costs and mitigate risk of future cost increases. We discuss the specific benefits of ownership in greater detail below and explain how our customers will realize these benefits.

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1. *Proposed CC at Sherco Site and CT in North Dakota*

By owning the CC that we propose to add at the Sherco site, we are able to use our existing site and interconnection rights, we will continue to employ current Sherco-based Xcel Energy employees, we will preserve options to continue to supply a large customer with steam, and we will avoid additional cost and risks associated with modifying our Black Start Plan. Our ownership of the CC allows the Company to secure these important benefits for our customers, and we believe it is in the public interest.

Ownership of a CT in North Dakota provides important options to be able to expand generation onsite in the future to serve our customers in the Red River Valley region. Expansion options could include a partnership with another utility or converting the facility to a CC. If a third-party owns the CT, these options may not be available or may be more expensive and difficult to implement. In addition, the North Dakota commission has expressed a preference for an ownership model to a PPA model. Thus, ownership best allows us to provide reliable service to our customers in the region.

2. *Proposed Renewable Resources*

An important and significant component of our proposed plan is the accelerated acquisition of renewable resources. Table 13 below, shows our proposed renewable resource additions during the planning period.

Table 13: Proposed Renewable Additions (MW ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800

As discussed below, we propose that approximately half of the renewable additions be Company-owned resources, which we have assumed in the Strategist modeling supporting our Current Preferred Plan. A balance between PPA and Company-owned resources ensures that our customers obtain the benefits of each ownership structure, and that the cost and risks are appropriately balanced. Table 14 below shows the renewable additions that we propose to own.

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Table 14: Proposed Owned Renewable Additions (MW ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	100	-	100	50	50	100	50	50	-	200	-	-	700
Wind	-	-	-	-	400	-	-	200	-	-	200	200	-	-	-	-	1,000

Table 15 below summarizes our current portfolio of wind resources, which contains approximately two-thirds purchased wind resources and one-third owned resources.[21]

Table 15: Current Wind Generation by Asset Type (MW)

Asset Type	Capacity Type	MW	Percent of Total
Owned	Nameplate	851.5	33%
PPA	Contracted*	1,759.9	67%

** Since we contract for a specific amount of energy, we do not maintain nameplate capacities in our records.*

Our solar portfolio, which primarily includes the Aurora project and the 187 MW resulting from our 2014 RFP is exclusively PPAs and third-party providers.

While we will also continue to acquire renewable resources through PPAs and third-party providers, concentrated efforts to improve the balance of our portfolio through expanded ownership of renewable resources is appropriate and necessary to minimize customer costs and balance risks. In this way, we believe our plan will capitalize on the strengths of each structure while ensuring that resources are acquired at reasonable costs for our customers.

Understanding the customer impacts of utility ownership versus purchased power is important to assessing the benefits of a balanced portfolio. While utility participation in competitive bidding may on its face be a means for such comparison, we have found that it is difficult to obtain an accurate assessment of the full economic and life-cycle costs and other benefits solely through this perspective. We believe a framework that allows the relative costs and benefits of our future acquisition of renewable resources to be assessed is a more reasonable and appropriate approach.

[21] Includes the most recently-approved Odell, Courtenay, Pleasant Valley, and Border Winds projects.

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Given similar access to suppliers, sites, and transmission, we also believe it is reasonable to assume that the capital costs of renewable development will be very similar between a utility-owned project and third-party development; thus, customer impacts will stem from the respective cost recovery mechanisms of the projects rather than development costs. Key issues affecting customer costs include differences regarding contract versus asset life and balance sheet impacts. We discuss each of these issues below.

3. Contract vs. Asset Life

Asset life affects the comparative costs of utility-owned versus purchased wind energy. A PPA is for a specific term that is likely shorter than the useful life of the facility. After the expiration of a PPA, the Company must return to the marketplace to procure replacement renewable energy. The market price of this replacement renewable energy will be based on a number of factors, including:

- Costs for new wind and solar generating facilities,
- Costs of capital,
- Market prices for electricity,
- The value of embedded environmental attributes, including Renewable Energy Credits (RECs) and Emission Rate Credits (ERCs) under the CPP, and
- PTC and ITC status and values.

Under utility ownership, by contrast, the asset remains in the utility portfolio until it is retired. Customers benefit when the actual useful life of the asset exceeds a comparable PPA's term, as they will continue to receive the capacity and energy for a longer period of time, lowering lifecycle costs. While we have modeled a 25-year life for both utility-owned and PPA renewable resources, there is the potential that the 25-year PPAs may not be widely available and also that utility-owned assets will exceed a 25-year life.

Based on our 2013 Wind RFP and 2014 Solar RFP, wind projects typically have PPA terms of 15 to 20 years with an asset life of 25-30 years, and solar projects typically have PPA terms of 20 to 25 years with an asset life of 25-30 years. While utility-owned assets may require refurbishment to extend their useful life, we would expect such costs to be lower than the market price of replacement renewable energy that would be required when a PPA expires. Life extension options for utility assets have traditionally offered cost-savings benefits for customers.

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The tradeoff for these long-term benefits is that relative to a PPA, utility-owned assets generally have higher costs in the early years when the rate base value is highest. For wind resources, direct pass-through to customers of the PTC will help offset this impact. Although there is no guarantee that ownership will provide significant present value savings compared to a PPA, it is certain that by using only PPAs to meet renewable resource needs, customers lose the opportunity for overall longer-term savings from the value of depreciating plant.

Figures 3 and 4 below illustrate the potential benefits provided by Company ownership of wind and solar resources. Customers could obtain significant benefits as shown by the shaded areas in the below figures.

Figure 3: Benefit Provided by Ownership
Illustrative 200 MW Wind Resource

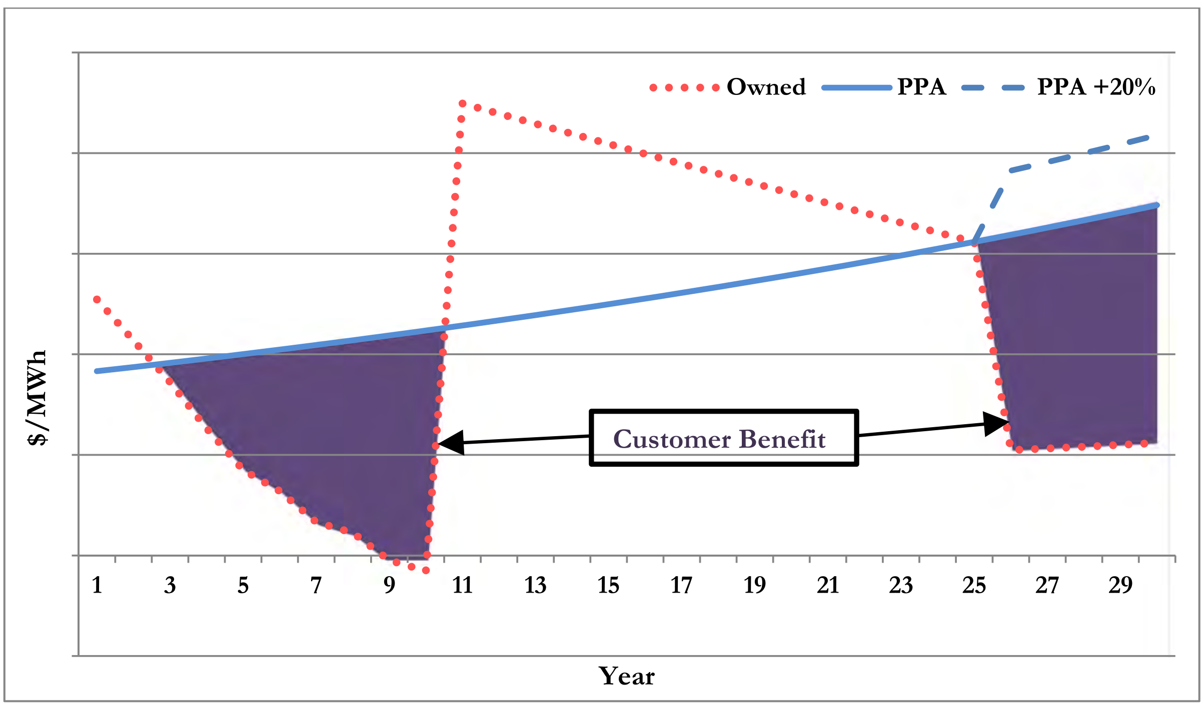

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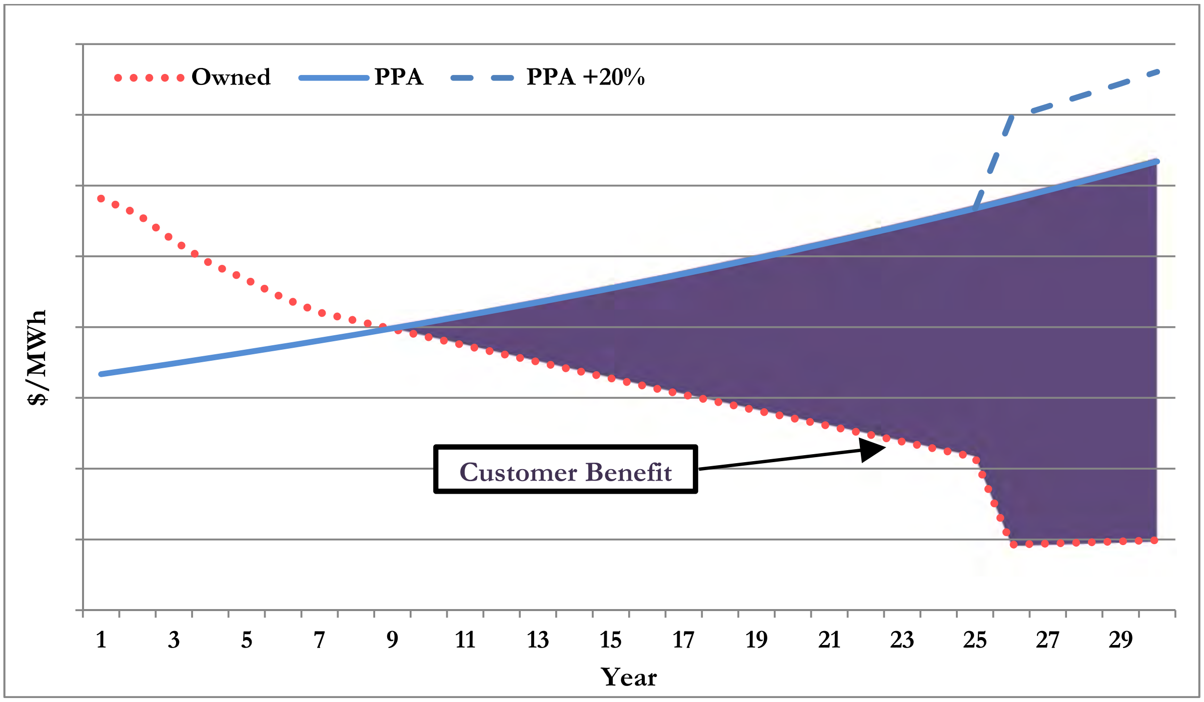
Figure 4: Benefit Provided by Ownership
Illustrative 50 MW Solar Resource



The cost per MWh for the PPA and utility-owned resources were derived from the wind and solar resources included in our modeling which assume a 25-year life. The utility-owned wind resource costs show additional reductions in the first 10 years due to the PTC while the PPA wind costs spread the benefits over the PPA term. The solar resources include the benefits of the ITC. These benefits are not achieved under a PPA structure, as the PPA must either be renegotiated or replaced when the contract term expires. In addition, ownership may help smooth rate impacts as the renewable resources procured in the near term will experience several years of depreciation prior to our projected procurement of significant additional resources in the mid-2020s.

4. *Balance Sheet Impacts*

Debt accounts for approximately half of the Company's total capital structure. The cost of debt is highly dependent on the credit profile of the utility, and higher-cost debt results in higher costs for customers. Generally speaking, companies with higher percentages of debt in their capital structure are considered riskier and pay higher rates for this debt, due to concerns that the company may be over-leveraged.

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PPAs are obligations the utility must pay that are viewed as additional debt on the utility's balance sheets – affecting the credit profile of the utility, which in turn affects costs to customers. Credit rating agencies also consider off balance sheet obligations in their risk assessment to determine credit ratings. These agencies impute additional debt to a utility's balance sheets based on the size, type, and terms of PPAs, thus increasing the financial leverage and risk of a company and also its cost of debt.

Likewise, auditors scrutinize PPAs to evaluate the effects of imputed debt and the lease-like characteristics of PPAs to ensure fair representation of obligations and creditworthiness on financial statements. Imputed debt and lease accounting effects have the potential to add significant debt-like obligations to the balance sheet used to determine the credit rating for the Company. In contrast to a PPA, owned projects are financed through both equity and debt which allows us to maintain our capital structure.

These issues highlight some of the implications of PPAs. Imputed debt has the potential to raise costs for customers in one of two ways: (1) through higher debt costs, as already described; and (2) through additional equity costs, as the utility may require additional equity in its capital structure to compensate for the additional debt-like obligations associated with the PPAs. Because these impacts affect the overall capital structure and capital costs, the costs of financing other utility infrastructure requirements are higher than they otherwise would be. While wind and solar PPAs are viewed more favorably than more traditional PPAs due to their energy-based payment structure, they nonetheless have imputed debt implications for the utility that will, over time, raise costs for customers.

Finally, we believe there are additional factors to consider when determining an appropriate balance between owned and purchased assets:

Potential unknown valuable attributes. If and when new value is attached to attributes of renewable resources (such as renewable energy credits were in the past), ownership of resources ensures that customers benefit from those attributes. If the resource is purchased through a PPA, those attributes may not accrue to customers. In the Silent REC Docket, the Commission was presented with this issue.[22] Under a PPA structure, there is uncertainty and risk associated with the allocation of any new valuable attribute that was not anticipated by the PPA. If the resource is utility-

[22] *See* Docket No. E002/M-08-440.

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owned, however, our Commissions will have increased control over how the value associated with any attribute is allocated.

Increased diversity in supply portfolio. Our proposed portfolio reflects an appropriate resource mix that achieves compliance with regulatory requirements, such as the CPP, and state policy objectives. Investors would be appropriately concerned if a utility's owned assets did not include the renewable assets required to achieve compliance. Thus, the financial health of the utility can be affected both by the aggregate mix of resources used to supply customers and the Company's mix of owned resources.

Complement to Xcel Energy's overall business plan. A key component of our overall business plan is environmental leadership. We believe that a balanced, clean energy portfolio is in the long-term best interests of our customers. Ownership of renewable resources is one means of demonstrating this commitment for our customers, regulators, and shareholders. We believe we must increase our investment in owned renewable resources to help maintain our financial health, minimize risks through a balanced portfolio, and reduce costs for our customers.

D. Proposed Acquisition Process

In this section, we describe our plan to acquire the replacement generation resources that will be necessary to address the capacity deficit created by our proposal to cease coal operations at Sherco Units 1 and 2.

Consistent with the Commission's January 6, 2016 Order, we will not submit a Sherco conversion plan proposal pursuant to Minn. Stat. § 216B.1692 (Emissions Reduction Statute) any earlier than one month following the Order in this Resource Plan proceeding. We expect that our proposal will take a similar approach to our 2002 Metro Emissions Reduction Project (MERP) petition under the Emissions Reduction Statute.[23] Following an overview and summary of the proposed projects, we will present further details including projected book life, capacity, capital cost, annualized emissions reductions, and proposed project schedule for the proposed thermal and renewable projects. We will address the benefits of our proposal, along with costs, customer impacts, and an analysis of alternatives. Our proposal will also contain a suggested procedural schedule, which we intend to develop in consultation with appropriate state agencies.

[23] Docket No. E002/M-02-633.

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Also similar to our approach in 2002, we intend to submit a cost recovery petition within 60 days of our proposal. The Emissions Reduction Statute gives the Commission the authority to implement rate riders to recover the cost of qualifying projects if they appropriately achieve environmental benefits without unreasonable consumer costs. Our filings will provide the factual and analytical support necessary for the Commission to affirm the two key issues in the matter:

- Whether the selections in our Proposal are appropriate, given their environmental benefits and costs, and
- If so, whether our proposed rate mechanism is appropriate and consistent with the terms of the statute.

Following approval of the Sherco conversion plan and associated cost recovery filing we would proceed using a similar approach to our previous MERP conversion efforts. The Company would commence the project under an owner-managed multi-contract approach similar to the previous MERP, CapX2020 and other major projects we have successfully completed in the NSP regions over the past 13 years. We would establish an agreed upon scope, schedule, and budget with the Commission prior to proceeding and would expect to provide regular updates to the Commission on the status of the project through completion.

We would utilize a competitive request for proposal (RFP) process to purchase the major equipment and acquire specialized engineering design and construction resources. An RFP bidding process for the major components of the project ensures we obtain the most competitive pricing. As with the MERP projects, the Company's Engineering and Construction organization would provide overall project management and oversight with support from departments within the Company for environmental, purchasing, safety, and startup & commissioning. Maintaining direct control through project management and oversight of contracts for associated equipment, materials, and service contracts will reduce costs and ensure project quality and timeliness.

We have demonstrated through our successful large scale, multi-year MERP and CapX2020 initiatives, a transparent owner-managed approach that includes regular Commission updates and project costs that stem from competitively-bid contracts for all materials and services delivers on-time and on-budget projects that are in the public interest.

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VI. CUSTOMER COST IMPACTS

As we have discussed, our Reference Case is a continuation of the plan we laid out in our 2010 Resource Plan. We now know that it would not achieve compliance with CPP requirements, nor is it consistent with our vision of being a leading provider of cost-effective clean energy. The Updated 2015 Plan that we proposed in January 2015 began to shift the Company to a significantly lower-carbon system; however, with the information currently available it is not certain that the Updated 2015 Plan will be sufficient to achieve CPP compliance under reasonable assumptions of the CO_2 reductions that could be required of the Company under Minnesota's CPP State Plan. Conversely, we are confident that our Current Preferred Plan will achieve CPP compliance, and also provide the reasonably-priced clean energy that our customers are asking for, appropriately balance state energy policy priorities, and optimize the system investments our customers have made to-date with new investments that will maintain reliability.

In this Section, we provide a long-term view of the cost impacts of our Current Preferred Plan. Additionally, at the request of the Commission and the Department at the December 2015 hearing regarding the procedural schedule for this proceeding, we discuss our view and provide illustrative concepts of a potential future market for CO_2 allowances.

A. Long-Term View

To show the cost impact of our proposal over the course of the planning period, we provide a Compound Average Growth Rate (CAGR) comparison of our Current Preferred Plan, Updated 2015 Plan, and Reference Case. We derived this long-term projection using a shorter-range financial forecast and a special purpose Strategist model, similar to how we projected the long-range cost of our plans in previous filings in this proceeding.[24]

Figure 5 below illustrates the cost differences between the Reference Plan, Updated 2015 Plan and our Current Preferred Plan, compared to the national average nominal cost CAGR. Specifically, the annual average cost delta between our Reference Case and our Current Preferred Plan is less than one-half of one percent. Our Current Preferred Plan also achieves significantly greater CO_2 emissions reductions and is the only one of the three plans that is virtually certain to achieve

[24] We describe this methodology in more detail in Attachment B.

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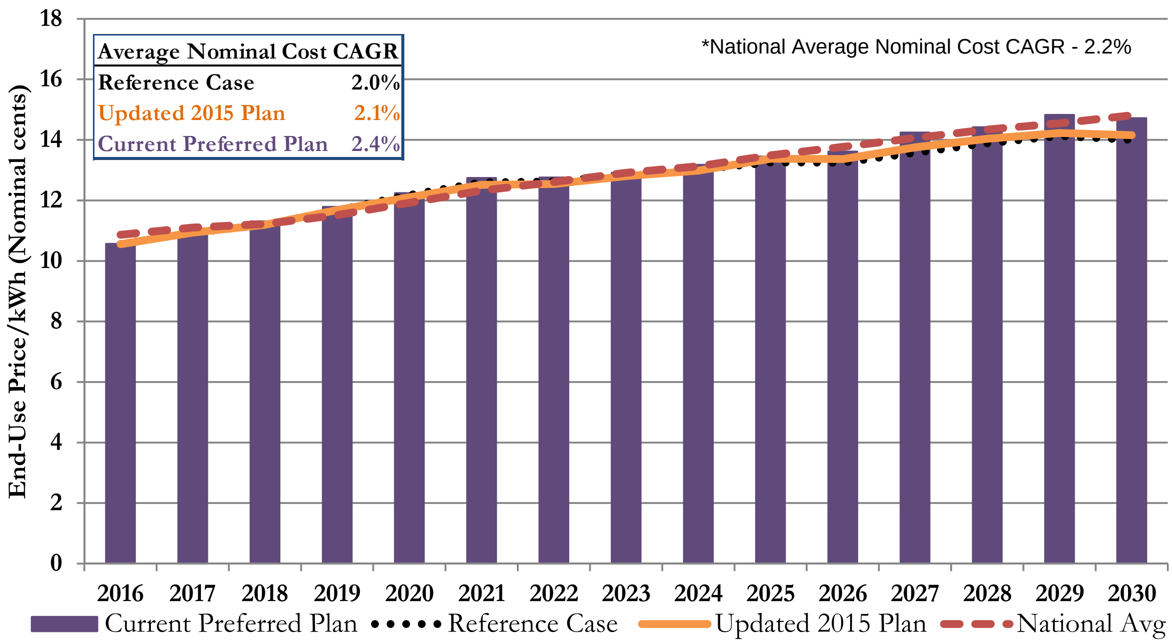
CPP compliance. Moreover, Figure 5 shows that the cost impacts associated with our Current Preferred Plan are roughly consistent with the expected national average increase in electricity prices, and over the long-term closely mimic the rate of inflation.

Figure 5: Current Preferred Plan Average Nominal Cost Comparison (NSP System)



*National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2015, Table Energy Supply, Disposition, Prices and Emissions. End use prices, all sector average.[25]

While this view of the estimated long-term plan costs is different than presented in previous filings, the relative values are consistent.

B. Potential Customer Benefits of CO_2 Allowance Proceeds

While our Current Preferred Plan is not primarily driven by the CPP, based on what we know now of the state implementation plan, we believe this plan not only achieves, but likely exceeds, the CO_2 emissions reductions that could be required of

[25] The EIA's Annual Energy Outlook was published in April of 2015, and based on federal, state, and local laws and regulations in effect as of the end of October 2014. Therefore, the potential impacts of pending or proposed legislation, regulations, or standards such as the CPP would not be reflected in these projections.

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the Company. As a result, the Current Preferred Plan may generate surplus reductions in the form of CO_2 allowances (if Minnesota's CPP state plan is mass-based) or Emission Rate Credits (if the plan is rate-based). Depending on the design of the state plan, the Company could monetize these surplus reductions on our customers' behalf to mitigate some of the cost impacts of transitioning to a significantly lower-carbon system.

We provide as Attachment H a preliminary analysis of the potential value of CO_2 allowances, in excess of compliance needs, under two hypothetical State Plan scenarios and assuming different CO_2 allowance prices. This analysis is preliminary and speculative because the size of the allowance budget allocated to the Company under the State Plan is not yet known; further, and CO_2 allowance prices in future markets can only be estimated. We describe in Attachment H the rationale we used for the CO_2 allowance prices used below, and provide details of the hypothetical State Plan scenarios labeled "Scenario 1" and "Scenario 2."

If we assume a constant CO_2 allowance price of $21.50 per ton (the midpoint of the Commission's regulatory cost range under Minn. Stat. §216H.06), and assume a "Scenario 1" State Plan that regulates existing units only, contains no allowance set-asides other than the Clean Energy Incentive Program, allocates allowances based on 2010-2012 generation at CPP-regulated units,[26] and does not limit the number of years of allowance allocation to a retired unit, the Current Preferred Plan would generate allowance revenues of about $540 million over 2022-2030 ($258 million in Net Present Value or NPV terms). At the same CO_2 allowance price, if we assume a "Scenario 2" State Plan that contains many allowance set-asides and only allocates allowances for two years after unit retirement, the Current Preferred Plan would generate allowance revenues for our customers of only $75 million over 2022-2030 ($33 million NPV). We have not reflected these speculative potential revenues in any of the cost estimates of our Current Preferred Plan, and provide them here as only a preliminary analysis.

Table 16 below shows the value at three different CO_2 allowance prices that correspond to the Commission's low, midpoint, and high regulatory cost values.

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[26] We note that EPA leaves the allowance allocation decision to states, and that discussion of the most appropriate allocation basis (generation or emissions, and whether any allowance set-asides are appropriate) is ongoing as of this filing.

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Table 16: Value of Potential CO_2 Allowance Sales
Under Two State Plan Scenarios
(millions, undiscounted, over 2022 to 2030)

	State Plan Scenarios		
Allowance Price	– 1 – Customer Value	– 2 – Customer Value	Value Impact to Customers
$9/ton	$226	$31	($194)
$21.50/ton	$540	$75	($465)
$34/ton	$853	$119	($735)

The "Value Impact to Customers" column in this table represents the estimated CO_2 allowance value transferred from the Company's customers to other parties by a State Plan that sets aside significantly more allowances, and discounts the value of retiring coal units by allocating allowances for only a short time post-unit retirement.

Since all allowance values are assumed to accrue to the Company's customers, a "Scenario 1" State Plan would provide around $540 million to help mitigate the cost impacts of transitioning to a lower-carbon energy system. A "Scenario 2" State Plan would provide only $75 million, which is $465 million *less* value to mitigate customer cost impacts, shifting much of the value from our customers to other parties.

We believe that through our involvement in the MPCA's CPP State Plan development process, we can identify opportunities to further offset the cost impact of our proposal and achieve the greatest value for our customers. We also believe there are rate mechanisms, described in more detail below, which can provide predictable cost recovery and help to smooth cost impacts for our customers.

C. Near-Term Customer Rate Impacts

In compliance with the Commission's January 6, 2016 Order and in order to approximate the near-term impacts of plan implementation on customer rates and bills, we provide as Attachment E a detailed rate analysis of our Current Preferred Plan and Updated 2015 Plan. This includes a five-year detailed rate impact analysis with the estimated impacts by class per year.

We note the following factors could impact rates in 2016-2020:

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- *Tax credit extension*: With the extension of the Production Tax Credit, the costs of 600 MW wind PPAs beginning in 2020 is reduced significantly from the Base Cost of Energy forecast (Docket No. E002/MR-15-827), which assumed those PPAs would not benefit from PTCs. Wind PPAs are recovered through the fuel clause, which is where the cost reduction would appear for customers.
- *Renewables ownership:* The addition of 200 MW of owned solar and 400 MW of owned wind would result in an increase in base rates or rider rates due to the ownership of 200 MW of solar and 400 MW of wind, presumably recovered in the RES Rider.
- *Ceasing coal operations at Sherco:* The ceasing of coal operations at Sherco Units 1 and 2 would result in increased depreciation expense.

Primarily due to the tax credit extension, both our estimated Updated 2015 Plan and our Current Preferred Plan forecasts show lower fuel costs than our 2016-2020 fuel forecast prepared at the time of the Base Cost of Fuel filing. For example in 2020, the ITC and PTC tax incentives would reduce fuel costs by $99 million in the Current Preferred Plan, while the Updated 2015 Plan results in a $66 million reduction.

VII. NUCLEAR RESOURCE UPDATE

In our October 2 Reply, we expressed our support for utilizing our carbon-free nuclear baseload resources through the existing plant licenses as a means of achieving our goal of a 60 percent reduction of CO_2 emissions from 2005 levels by 2030. At the same time, we explained that our projected capital spend for Prairie Island is outpacing the estimates included in our Changed Circumstance filing in 2012.

We noted specifically that our five-year capital expenditure forecast from 2016 through 2020 has increased by roughly $175 million above what was anticipated in 2012, and that our forecast for the thirteen-year period from 2021 through 2034 would likely need to increase by roughly $600 to $900 million. We also noted that our fixed operating and maintenance (Fixed O&M) costs are lower than previously modeled and that our decreased Fixed O&M forecast largely offsets the increase in our forecasted capital spend.

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The Commission expressed understandable concern over our updated capital forecast during hearings in December 2015. We address those concerns here by providing additional information and analysis relating to our support for nuclear and to the costs associated with the continuing operation of Prairie Island. In particular, we provide modeling that takes into account our updated capital and Fixed O&M forecasts and demonstrates that Prairie Island has been, and continues to be, a cost-effective resource for our customers. We also discuss our updated capital expenditure forecasts for the periods from 2015-2020 and 2021-2034 at Prairie Island.

We believe the information provided in this section supports our continued operation of Prairie Island, including the investments we need to make to safely and reliably operate the plant over the next few years. We nevertheless recognize that our opinion is one of several that need to be considered in this process, that stakeholders would like to better understand the implications of our updated forecasts, and that there is some uncertainty at play when considering the costs to operate a two-unit nuclear plant for the remaining 19 years of its licensed life. Utilities, regulators, and stakeholders around the country are grappling with similar issues as they try to balance the increased regulatory pressure and costs associated with nuclear against emerging policies aimed at reducing CO_2 emissions.

We believe that any decision regarding the long-term future of Prairie Island should be made after a deliberate and thoughtful dialogue between the Company, our regulators, and our stakeholders. We further believe this dialogue should be informed by a longer-term, in-depth analysis of the cost-effectiveness of Prairie Island and the alternative paths that could be taken with respect to the plant. In fact, we have begun this work and share a preliminary analysis of one potential alternative later in this section. If the Commission and our stakeholders want to further explore this or other alternatives, we are committed to doing the additional work necessary to advance a fully informed and thoughtful decision-making process. We expect that a full analysis of the operations, economics, and potential alternatives for Prairie Island could be completed in the next 18 months, and we welcome the opportunity to cooperate with our regulators and our stakeholders on such a significant decision.

A. Relation to Supplemental Rate Case Testimony

Following our October 2 Reply, the Commission ordered the Company to file supplemental schedules and testimony in its pending electric rate case that describe

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and compare projected and actual Life Cycle Management costs (and, to the extent relevant, Extended Power Uprate costs) from 2008 through 2020 by generating unit and year, including the proposed 2016 test year, and the 2017 and 2018 plan years. As part of those descriptions and comparisons, the Company was ordered to include all changes and updates to projected costs from 2008 onward and to include all cites to relevant certificate of need, resource plan, and general rate case dockets. The Commission also ordered the Company to provide as part of those schedules and testimony a comparison of the relevant parts of the proposed 2016 test year, the 2017 plan year, and the 2018 plan year to the proposed five-year capital budget in the Company's pending Resource Plan proceeding.

In compliance with that Order, we are filing supplemental Direct Testimony in our pending rate case docket from Company Witnesses Christopher B. Clark (President), Timothy J. O'Connor (Senior Vice President and Chief Nuclear Officer), Scott L. Weatherby (Vice President for Nuclear Finance and Planning), and John J. Reed (Chief Executive Office at Concentric Energy Advisors). That testimony focuses on the period from 2016 through 2020, the additional $175 million of capital expenditure above what was anticipated in 2012 for that period, and why the capital projects underlying that forecast are necessary during those years and in our customers' best interest.

In this Resource Plan Supplement, by contrast, we address not only the next five years but also the latter portion of Prairie Island's licensed life and the additional $600 to $900 million in capital that we anticipate spending between 2021 and 2034. Because resource planning takes this longer view, we believe it is the appropriate forum to consider whether it is economic and prudent to operate Prairie Island through the end of its licensed life. We therefore welcome an in-depth discussion regarding the future of Prairie Island and, to that end, propose a process to continue that discussion after we have had additional time to study the impacts of continued operations, as well as potential alternatives.

B. Prairie Island's Past and Current Cost-Effectiveness

Our support for utilizing our nuclear baseload through the existing plant licenses is primarily driven by our conclusion that it is beneficial for our customers to do so. We recognize that the principal question in this regard is the plant's cost-effectiveness on a going-forward basis. We believe that it is also helpful, though, to consider the forecasts and modeling we presented in connection with our 2008 certificate of need and 2012 changed circumstance filings. These demonstrate that

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Prairie Island has always been cost-effective, even when we account for our updated capital forecast. We therefore briefly address these earlier forecasts and models before turning to our prospective analysis.

1. *Past Forecasts & Modeling*

At the time we filed our certificate of need in 2008, we provided an estimate of capital costs running to the end of Prairie Island's licensed life in 2034 in an effort to measure the plant's cost-effectiveness compared to either a super critical pulverized coal unit or a natural gas CC unit. We provided this information in response to Minn. Stat. §216B.243, subd. 3b, which states that "[a]ny certificate of need for additional storage of spent nuclear fuel for a facility seeking a license extension shall address the impacts of continued operations over the period for which approval is sought."

Because we sought authorization for enough casks to operate Prairie Island until 2034, we provided our best judgment with respect to the "impacts of continued operations" until that time. Looking to historical capital expenditures, we estimated that our routine capital investment would average approximately $20 million annually ($10 million per unit) and that we would spend an additional $600 million on large capital investments from 2008 through 2034. Using these numbers, we concluded that continued operation of Prairie Island was cost-effective by a margin of $2,194 million in PVRR. We then updated our capital forecast for Prairie Island in our 2012 changed circumstance filing and included additional capital expenditures in that model.

For a number of reasons that are discussed below, our 2008 capital forecast has proven to be lower than the actual costs incurred to-date. Likewise, our 2012 forecast appears to be lower with respect to our updated forecast for the out-years of Prairie Island's licensed life. As an initial matter, however, it is important to contrast our 2008 capital expenditure forecast from one more typically associated with a certificate of need filing and from the Monticello prudence review. In the Monticello docket, for instance, we had already spent more than forecasted in our LCM/EPU certificate of need filing, and we sought recovery of those capital expenditures after the construction project was completed.

There is no construction project at issue here. Our 2008 filing related to dry-storage casks and provided a forecast related to the "impacts of continued operation" for a two-unit nuclear plant over a twenty-six-year period. It was the first time we

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provided such an estimate and the first time we forecasted capital expenditures for the out-years of an extended-life nuclear plant. And unlike Monticello, we are updating the Commission with respect to our increased capital forecast having not yet exceeded our 2008 forecast and not expecting that we will exceed the total cost (capital plus Fixed O&M) we forecasted in our 2008 filing.

That said, one reason for the higher-than-anticipated capital expenditures is that our Nuclear Regulatory Commission (NRC) mandated compliance expenses have increased substantially in recent years, both as a result of new NRC requirements following the Fukushima Daiichi incident, and as a result of increased oversight and regulation by the NRC generally. Additionally, our estimate of spending $10 million per unit annually for routine capital investment has proven to be insufficient, despite that having been a reasonable estimate in light of historical spending up to and including 2008. Our experience with routine capital investment over this period mirrors that of other utilities operating similar nuclear plants.

Although our capital expenditure forecasts have increased since 2008, our Fixed O&M forecasts have decreased in nearly equal measure. In 2008, we provided a conservative estimate of Fixed O&M costs in connection with our certificate of need filing, which was based on our historic spending up to that point. Since that time, however, we have observed significantly lower-than-forecasted Fixed O&M spend, which caused us to revisit that forecast in conjunction with our resource plan and to reconsider what future Fixed O&M growth will be over the next 19 years of Prairie Island's licensed life. Based on historical spending from 2008 to present, we now forecast spending more than $1 billion less in Fixed O&M at Prairie Island from 2015 through 2034. And if we look at total spend (capital plus Fixed O&M) in connection with Prairie Island, our current forecast results in PVRR that is $981 million less than our 2008 certificate of need forecast and $91 million less than our 2012 changed circumstance forecast. Thus, our revised Fixed O&M forecast not only offsets our revised capital expenditure forecast, it results in a projected total project cost that is substantially less than we anticipated in both 2008 and 2012.

Had we used our current capital expenditure projections in our 2008 model, it would have shown that Prairie Island remained a valuable, cost-effective resource by a margin of approximately $2.04 billion in PVRR. Likewise with our 2012 changed circumstance proceeding, Prairie Island would have remained a cost-effective resource by a margin of approximately $305 million in PVRR, using the model from that filing. Further, because our 2012 modeling assigned no cost to CO_2, the PVSC of Prairie Island under that analysis would have been substantially higher. As a

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result, our updated capital and Fixed O&M forecasts would not have changed our conclusions with respect to the continued operation of Prairie Island in either the 2008 certificate of need or 2012 changed circumstance proceedings.

2. Prairie Island's Current and Future Cost-Effectiveness

We now turn to the present-day cost-effectiveness of Prairie Island. For this analysis, we used our current Strategist modeling from this docket and considered a base case with the current forecast for ongoing capital and O&M expenditures compared with a scenario where Prairie Island is retired immediately. In a number of ways, this analysis is highly conservative. First, we have assumed that all of the capital and O&M expenditures for Prairie Island for 2016 through end of life can be avoided entirely, despite the fact that nuclear units continue to experience significant Fixed O&M costs during the various stages of decommissioning and despite the fact that the NRC would likely require a number of Fukushima-related and other mandated projects to be completed even following a shutdown.

Second we have not included any adjustments for accelerated depreciation of the existing asset, or changes to decommissioning costs or fund accruals, both of which we address in greater detail later in this section. Third, we have not included the costs of addressing transmission system impacts that would be caused by shutting down a significant baseload unit, as we have not yet studied these transmission effects in detail. Finally, we have assumed that replacement capacity could be installed "overnight" in 2016, and Strategist was allowed to optimize both the immediate replacements and balance of the expansion plan through the end of the study period. For a number of reasons discussed later in this section, it is simply not possible to immediately retire Prairie Island, or any nuclear plant. Major system transitions of this sort take years to study, plan, and execute, and industry experience teaches that unplanned shutdowns can be enormously expensive by comparison.

The results of this very conservative analysis are shown below in Table 17:

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Table 17: Prairie Island Compared to a Natural Gas Combustion Turbine

Resource	PVSC	PVRR
Prairie Island	$52,519	$46,618
Combustion Turbine	$53,750	$46,824
Difference	$1,231	$206

Even our most conservative analysis, then, shows that "overnight" replacement of Prairie Island would result in $1.231 million of additional PVSC. We also evaluated the PVSC and PVRR associated with the capital expenditure and Fixed O&M forecasts over the near-term period from 2016-2020. Continued operations of Prairie Island through this period results in a PVSC savings of $456 million and PVRR savings of $177 million compared to the overnight replacement scenario.

To be sure, the PVRR of running Prairie Island results in a closer call. In this way, the social cost of carbon plays a role in driving our support for continuing to operate Prairie Island through its licensed life, just as it does our decision to cease coal operations at Sherco Units 1 and 2 in the 2020s. We further recognize that changes to certain modeling assumptions, such as lower gas forecasts, could cause the PVRR numbers to suggest – under this limited analysis – that retiring Prairie Island in the near term might result in lower PVRR. It is important to keep in mind, however, this is a theoretical analysis intended to provide a preliminary look at Prairie Island's baseline economics, that it cannot substitute for an in-depth study that accounts for actual retirement and replacement costs, and that there are significant benefits to our nuclear fleet that are not captured by this, or any, Strategist model.

3. Operational & Policy Concerns

We believe that continued operation of our nuclear fleet is also the best path forward from both a policy and reliability perspective. Nuclear comprises more than half of our carbon-free generation and – at the same time – provides our system with a baseload energy resource that ensures critical system reliability. In this way, it is a keystone of the carbon-reduction goals set forth in our Current Updated 2015 Plan. Renewable technology such as wind and solar cannot fulfil this role at a reasonable cost today. As a result, any near-term replacement of our nuclear plants would involve the addition of more natural gas to our fleet, meaning the closure of Prairie Island would have twin effects of heightening our customers' exposure to gas

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price volatility and significantly increasing our CO_2 emissions. We do not believe this is in the best interest of our Company, our customers, or the states we serve.

We recognize, however, that battery technology is evolving, that renewable costs have decreased in recent years, and that reliable renewable baseload energy may be on the horizon. With that in mind, we see our nuclear units as critical to meeting our carbon-reduction and reliability goals in the near-term (including our compliance with the CPP) and also as a bridge that can facilitate a transition to even greater renewable generation in the longer-term as battery technology improves and costs decline. At the same time, our nuclear fleet is an integral part of our diversified generation portfolio and provides an important hedge to gas price volatility.

Finally, combining the cessation of coal operations of Sherco Units 1 and 2 along with the shutdown of Prairie Island all in the 2020s would present enormous challenges and costs with respect to replacement generation, transmission, and system reliability. The continued operation of our nuclear fleet as a bridge resource will allow for a careful and focused transition away from coal generation in the 2020s before addressing the future of other baseload units.

C. Forecasted Investments

1. *Forecasted Investments from 2016-2020*

In total, we anticipate investing approximately $490 million in capital at Prairie Island from 2016 through 2020. This is roughly $175 million more than we forecasted as part of our 2012 changed circumstance filing. There are a few key drivers of our increased capital spend during this period. First, $84 million of this increase is due to regulatory mandates from the NRC. As described in our previous two rate cases, these NRC Fukushima, fire safety, physical security, and cyber security requirements did not exist or were not fully known between 2008 and 2012.

More than half of the remaining $90 million is a result of our decision to defer certain projects from the rough timeframes anticipated in our 2008 and 2012 forecasts. In fact, we invested $51 million less from 2008-2015 than we forecasted in our 2012 changed circumstance filing. The remaining capital expenditures during this period simply reflect our inability to perfectly forecast costs in a certificate of need proceeding broadly focused on the remaining life of a plant, as well as increasing costs of nuclear construction and life-cycle maintenance across the industry.

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As detailed in Mr. O'Connor's Supplemental Direct Testimony in our pending rate case, the major capital investments forecasted for 2016-2018 include reactor coolant pump replacements, heater drain tank pump speed controls, motor rewinds/replacements, cooling tower replacements, and the main electrical generator replacement for Prairie Island Unit 1. In his Supplemental Direct Testimony, Mr. O'Connor describes each of these projects and explains why they are necessary to safely and reliably operate the plant, even if Prairie Island were not to operate until the end of its licensed life.
Department of Commerce Information Request No. 74 in our currently pending electric rate case requested that we provide an estimate of the necessary retirement dates for Prairie Island Units 1 and 2 under the assumption that substantial (over $40 million per year for the site) new capital expenditures would not occur starting in 2016. Our forecasted capital expenditures for the combination of mandated compliance projects and dry fuel storage alone total $38.9 million in 2016, $36.1 million in 2017, and 34.8 million in 2018. These expenditures are necessary to operate the plant within the NRC's mandates and would leave very little additional capital within the $40 million annual budget to complete basic and necessary LCM projects during these years. Given this, and the fact that any single outage could require more than the remaining amount of budgeted capital to resume operations, it is impossible to predict how long Prairie Island could operate under these budget constraints.

2. Forecasted Investments from 2021-2034

In our October 2 Reply, we explained that our forecast for the fifteen-year period of 2021 through 2034 would likely need to increase by roughly $600 to $900 million. We revised our forecast following a project-by-project analysis of anticipated capital investments at Prairie Island from 2015 through 2034, and we believe that it is responsible to anticipate and plan for all of the projects underlying our forecast. In other words, our updated forecast reflects our best judgment regarding these costs, which we presented to the Commission in October so that it can undertake a thorough assessment of our Current Preferred Plan. That said, it is not possible to accurately predict not only which projects will be necessary over a 19-year period, but also what those projects will cost. It is likewise not possible to predict what regulatory mandates will arise in the future, and what compliance with those unknown mandates might cost. Given this uncertainty, we understand certain stakeholders' desire to explore and maintain future optionality with respect to Prairie Island, and we address those concerns below.

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D. Future Optionality at Prairie Island

As already discussed, we believe that Prairie Island continues to benefit our customers by producing cost-effective, carbon-free baseload energy that is a keystone to our carbon-reduction goals and a bridge to additional renewable development in the future. We recognize, however, that it is impossible to perfectly forecast costs for the remaining 19 years of Prairie Island's licensed life and that certain of our stakeholders may want to explore alternatives based on that uncertainty. To that end, we have begun to identify and analyze one potential alternative for the plant around the 2025 timeframe. We recognize that other alternatives exist. We present this preliminary analysis as an example of the considerations and analyses that would go into an in-depth discussion of alternatives, and we welcome further dialogue regarding this or other alternatives.

Before proceeding with any in-depth discussion of alternatives for Prairie Island, we would need to conduct a detailed study of its effect on our transmission system, as we did in connection with our proposal to cease coal operations of Sherco Units 1 and 2. This would include a MISO Y2 Study, our own reliability study, and a black start study – just as we are providing in connection with our Current Preferred Plan. And as we did for Sherco, we would need to conduct impact studies relating to our employees at Prairie Island and the community around Red Wing, Minnesota. Finally, the technical studies completed in connection with our Sherco proposal may need to be reconsidered, as the study models assumed that Prairie Island would continue to operate.

If the Commission and our stakeholders wish to have a longer-term discussion concerning the future of Prairie Island, we are committed to completing this work, which we expect would take approximately 18 months. At that point, we would welcome input from stakeholders and the Commission, and we believe that a decision could be made with respect to Prairie Island's future sometime in 2018. If a decision was reached to pursue an early retirement for Prairie Island, we would need an additional seven years to plan for the shutdown and decommissioning, including the construction of replacement generation and any transmission projects that would be needed to maintain system stability. This planning period is critical, as recent industry experience teaches that hastily planned (or unplanned) shutdowns can be extraordinarily expensive as compared to shutdowns that are preceded by several years of planning. Company witness Mr. John Reed discusses the importance of advanced planning for nuclear retirements in his Supplemental Direct

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Testimony, which is being filed in our pending rate case contemporaneously with this Supplement. The seven-year timeline is also similar to the one we have proposed in connection with Sherco Units 1 and 2, and would result in a shutdown of Prairie Island around 2025.

To be clear, we do not currently foresee an economically prudent time to retire Prairie Island prior to the end of its licensed life. That said, we believe that an off-ramp in the 2025 time period would result in certain financial benefits as compared to an earlier retirement. Net plant balance is set to peak in 2018 at $1.127 billion. A retirement in that time period would result in substantially increased stranded costs, in addition to the costs otherwise associated with early retirement. During the early 2020s, however, net plant balance begins to decrease and, by 2025, would be within approximately $125 million of today's value of $917 million. That additional $125 million of net plant would itself be more than offset by the additional 10 years of investment growth in our decommissioning fund, which has a current market value of approximately $725 million and earns a return of approximately 5-6 percent (or between $36 million and $43 million) annually.

Additionally, if a decision were made around 2018 to retire Prairie Island in the mid-2020s, we could reduce our capital expenditures during the intervening years, as we normally anticipate lower capital spend in the years leading up to a plant's planned retirement. While we have not yet studied this capital adjustment in-depth, we estimate that our capital expenditures could be reduced such that net plant in 2025 would be significantly less than today's value of $917 million—provided we have several years to plan for the retirement. The strategy of reduced capital expenditures in the 2020s would come with a risk of a modest capacity derate at Prairie Island beginning around 2022 due to decreased capital investment, but we see this as a reasonable risk if the Commission and our stakeholders wish to pursue an early retirement.

The growth of our decommissioning fund is a significant factor that should be taken into account when considering alternatives to operating Prairie Island through its licensed life. Table 18 below compares the approximate amounts of customer contributions versus investment growth that would be needed to fully fund decommissioning at Prairie Island for three examples of potential retirement years:

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Table 18: Decommissioning Funding Broken Into Customer Contributions and Investment Growth

	2020	2025	2034
Customer Contributions	$518 million (58.67%)	$374.5 million (40.87%)	$10 million (0.64%)
Investment Growth	$319 million (41.33%)	$541.8 million (59.13%)	$1.552 billion (99.36%)

In short, the longer our decommissioning fund enjoys market growth, the less our customers will be required to pay to fund decommissioning at Prairie Island. This, in combination with the decreasing trend in forecasted net plant balance over the early 2020s, suggests that a retirement significantly before 2025 would involve substantially higher decommissioning and stranded costs.

As already discussed, we have conducted some preliminary modeling around the replacement of Prairie Island with a natural gas CT plant in 2025. Doing so would result in an increase of $929,614 million in PVSC and $601,257 million in PVRR. This analysis incorporates our current best judgment as to the costs of building replacement generation, the depreciation associated with Prairie Island, and the acceleration of decommissioning costs at Prairie Island – including most significantly, the elimination more than a dozen years of investment growth. Our PVSC model also incorporates the regulatory cost of emitting additional CO_2, which we have valued at $21.50 per metric ton beginning in 2019.

It is important to note that we have not conducted an in-depth replacement study with respect to Prairie Island. That analysis would include many of the technical studies that have already been completed for Sherco and the inclusion of specific costs related to transmission remediation and decommissioning that we are not currently in a position to forecast. We view this high-level analysis as buttressing our earlier cost-effectiveness modeling and as supporting the continued operation of the plant, at the very least through the next few years as we further study alternative scenarios.

E. Next Steps

There is much work to be done if the Commission wishes to pursue an in-depth discussion concerning the future of Prairie Island. As already discussed, we would need to complete several technical and impact studies, as we did in connection with

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our Sherco proposal. We may also need to reevaluate the technical studies completed in connection with our Sherco proposal, in which we assumed the continued operation of Prairie Island on our system. We believe this analysis is critical to making a fully informed judgment on this significant planning issue, and we are committed to doing this work over the next 18 months if the Commission wishes to further explore alternatives to operating Prairie Island through its current licensed life.

Prairie Island remains cost-effective, and our near-term investments are necessary to continue operating the plant today. Additionally, the bulk or our anticipated capital investments will occur in the out-years of Prairie Island's licensed life. As a result, there is time to engage in a thoughtful process, and we welcome this opportunity to dialogue with our stakeholders in hopes of charting a path that is best for our customers and the states we serve.

VIII. ACTION PLANS

A. Five Year Action Plan (2016-2020)

Our Five Year Action Plan discusses near-term actions by resource type, which is primarily focused on wind and solar resource additions.

Wind. The remaining 400 MW of the 750 MW of wind generation resulting from our 2013 RFP is expected to achieve commercial operation in 2016, which includes the 200 MW Courtenay project for which the Company took over ownership in 2015. In light of the recent PTC extension, we plan to develop and finalize our acquisition plan later in 2016 for securing an additional 800 MW of PTC wind by 2019. Currently, in order to obtain the full benefit of the PTC, wind projects must secure a "safe harbor" designation by the end of 2016 by incurring at least 5 percent of the project costs. Construction must be completed by the end of 2018. The PTC is reduced in subsequent years for projects meeting these milestones. We believe it is in the best interest of our customers to obtain the full PTC value; it may therefore be necessary to bring a wind acquisition proposal before the Commission in the latter half of this year for approval on an accelerated schedule.

Solar. The 187 MW of utility-scale solar generation resulting from our 2014 RFP, and the 100 MW Aurora Solar project resulting from the 2012 CAP proceeding are expected to achieve commercial operation in 2016. In light of the recent federal 30 percent ITC extension, we plan to develop and finalize an acquisition plan later in

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2016 to secure an additional 400 MW of 30 percent-ITC eligible utility-scale solar resources by 2020. There are similar safe-harbor provisions for the ITC as there are for the PTC for wind, however we have a longer runway. We note that we may adjust the amount of utility-scale solar resources we would seek based on the amount of small solar resources added to our system. The amounts indicated in our Expansion Plan (Table 2) are based on the updated small solar forecast we discuss in Attachment B to this Supplement.

Hydro. We will continue to evaluate the potential and value of hydro resource options including the potential for hydro resources from Manitoba Hydro beyond the current contracts that expire in the mid-2020s.

Natural Gas/Oil Peaking. We will continue to analyze older CTs on the NSP System to avoid impact of increased forced outages due to a major equipment failure and associated unexpected loss of capacity.

Coal. After this Resource Plan proceeding concludes, we will develop and submit a proposal that seeks to implement our proposal to cease operation of Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026, and construct replacement generation resources needed as a result of these changes

Nuclear. Continue to utilize our cost-effective nuclear resources to achieve carbon-reduction goals and maintain reliability. Continue to dialogue with our regulators and stakeholders regarding the future of Prairie Island. If the Commission wishes to further explore alternatives to operating Prairie Island through its current license, complete the economic, technical, socioeconomic studies necessary to advance that discussion.

North Dakota. If the North Dakota commission takes action to approve our proposed Negotiated Agreement, we expect to begin working with Commission staff in 2016 toward developing a Resource Treatment Framework that would likely be filed with the Commission sometime in 2017. We believe additional discussions with all of our state Commissions will be necessary during the five-year action planning period to address divergent energy policies and changes in cost allocations that may result.

B. Long Term Plan Action Plan (2021-2030)

Proposed actions during the 2021-2030 period:

- Complete preparations for ceasing coal operation of Sherco Unit 2 in 2023 and Sherco 1 in 2026.
- Complete preparations to add our proposed natural gas CC at the Sherco site in 2026, achieving commercial operation prior to ceasing coal operations at Sherco Unit 1.
- Complete the natural gas infrastructure to supply the proposed Sherco CC.
- Complete preparations to add the proposed natural gas CT in North Dakota by the end of 2025.
- Effectively manage planned retirement of older CTs.
- Evaluate and determine the merits of extending or renewing expiring wind, thermal and hydro generation PPAs.
- Actively work to identify and act on opportunities to implement cost-effective and reliable distributed generation, electric storage units and other commercial ready technologies that are responsive to customer needs and comply with applicable requirements.

Minn. Stat. § 216H.02, subd. 1 requires that we provide an update on our progress toward the goal of achieving 80 percent CO_2 reduction by 2050. We expect our Current Preferred Plan to achieve at least at 35 percent CO_2 reduction from 2005 levels by 2020 and nearly 60 percent by 2030 – positioning us well to help Minnesota achieve its objective to reduce CO_2 by 80 percent by 2050. We note that our Monticello and Prairie Island nuclear facilities are essential to achieving the reductions we propose in our Current Preferred Plan and the 2030 CPP objectives. We discuss our nuclear units and their role on the NSP System more in depth in Section VII of this Supplement.

Our Current Proposed Plan achieves a 60 percent reduction in CO_2 emissions by 2030 milestone by adding 3,200 MW of new renewables and ceasing coal operations at Sherco Units 1 and 2 during the 2016-2030 planning period. Renewable additions begin with an 800 MW addition of competitively-priced PTC wind additions by 2020 and an additional 1,000 MW of non-PTC wind by 2030. Solar additions include adding 400 MW of competitively priced utility-scale ITC solar by 2020 and additional 1,000 MW by 2030. This adds to the 287 MW of utility-scale solar going into service in 2016. We note that we now expect small-scale solar resources to potentially reach 1,100 MW by 2030, which we discuss in Attachment B.

IX. PUBLIC INTEREST ANALYSIS

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Based on our detailed analysis, we conclude that the Current Preferred Plan is in the public interest. It puts the Company on a path to transform its fleet in a planful, coordinated manner that ensures we will meet our obligations under the CPP and the most stringent of our state renewable energy and carbon reduction requirements, while effectively managing costs and preserving flexibility on behalf of our customers. It provides our customers, employees, and our communities with certainty, while also maintaining a balanced diversity of energy sources, and investment opportunities that benefit our state economies and communities. Finally, it promotes an orderly, gradual transition of our generation fleet and thus avoids a scenario where the Company may have to retire and replace five baseload generating facilities in the early 2030s.

Minnesota Commission rules (Minn. R. 7843.0500, subp. 3) identify the factors that the Commission is to consider when determining if the Resource Plan selected is in the public interest. More specifically, these rules require that resource options and resource plans are to be evaluated on their ability to:

A. Maintain or improve the adequacy and reliability of utility service,
B. Keep the customers' bills and the utility rates as low as practicable, given regulatory and other constraints,
C. Minimize adverse socioeconomic effects and adverse effects upon the environment,
D. Enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations, and
E. Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

Our Current Preferred Plan is best able to meet these criteria, especially when analyzed on a comprehensive basis in light of the planning landscape facing the Company and the industry.

A. Reliability

Our Current Preferred Plan is designed to maintain the adequacy and reliability of the NSP System and will allow the Company to continue to provide safe and reliable service to its customers. Our plan promotes an orderly, gradual transition of our generation fleet and thus avoids a scenario where the Company may have to retire and replace five baseload generating facilities in the early 2030s.

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B. Impact to Customers' Bills

We developed our Current Preferred Plan with impacts to customers in mind. Given the regulatory and other constraints of the planning landscape, we sought to achieve additional flexibility and achievement of policy goals at a reasonable additional cost. For an incremental increase of less than one-half of one percent over the planning period compared to business as usual, we achieve nearly 60 percent reduction in our CO_2 emissions from 2005 levels, near certain CPP compliance, and assured reliability for our customers.

C. Socioeconomic and Environmental Effects

Our Current Preferred Plan will benefit our states by advancing both federal and state energy policies and by being nearly certain to comply with the final Clean Power Plan rules. It will also benefit our communities by allowing adequate time to transition our workforce and promoting economic development during this fleet transition. For these reasons, we believe that our Current Preferred Plan charts the right path forward for our Company and stakeholders.

D. Flexibility to Respond to Change

Our Current Preferred Plan was developed to position the Company well in the current planning landscape. Obtaining strategic flexibility is a key component of doing so. This flexibility enhances our ability to respond to changes in the financial, social, and technological factors affecting our operations during the planning period – and preserves optionality for us to respond to these factors beyond the planning period.

E. Limiting Risks

Much like the flexibility to respond to change, the strategic flexibility inherent in our Current Preferred Plan limits the risk of adverse effects on the Company and our customers from financial, social, and technological factors beyond our control. Key to limiting such risk is our planful and coordinated fleet transition that ensures we will meet our obligations under the CPP and the most stringent of our state renewable energy objectives and carbon reduction requirements.

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We envision an energy future that includes a dramatic reduction in carbon emissions so that, by 2030, our energy mix will be 63 percent carbon-free. Taking action to transition our fleet now mitigates the costs and risks of retiring a significant proportion of our baseload generation in the same time period along with environmental regulatory risks to the economic viability of our older coal units, and provides certainty to our customers and stakeholders throughout the planning period. Our proposal to achieve this vision will benefit our customers, communities, and the states we serve. Our customers will benefit from our cost-effective transition to the cleaner energy future they want, while preserving the reliable and safe service they expect, which we can accomplish for just a fraction of a percent more in incremental cost over earlier plans. Our Current Preferred Plan represents the best option to meet customers' needs in light of the planning landscape and presents the best path forward for the Company, our customers, and the energy future of the Upper Midwest area. For these reasons, we believe our Current Preferred Plan is in the public interest, and we respectfully request the Commission's approval for planning purposes.

Compliance Matrix

This Supplement to Xcel Energy's 2016-2030 Upper Midwest Resource Plan in part responds to the Minnesota Public Utilities Commission's ORDER REQUIRING SUPPLEMENTAL FILING issued January 6, 2016 in Docket No. E002/RP-15-21. The following table lists each Order requirement and cross-references the section in Supplement where we address each item.

The Supplement also responds to the November 6, 2015 Minnesota Department of Commerce request for various information , as well as the Department's December 17, 2015 Information Requests Nos. 66 through 74, in which the Department requested responses be provided concurrently with the Supplement. We have addressed the IRs either in IR format via standard email delivery and uploaded to the eDockets site or in the Supplement as noted below.

Order Requirements

Order Point	Content of Order Point	Location of Order Point as Addressed in Supplement
Order Point 1	Xcel shall file a supplement to its resource plan no later than January 29, 2016, and shall continue to share information with stakeholders. Upon submission, the Department will review Xcel's supplemental resource plan filing to determine the time the Department will need to analyze the new filing. Within 30 days of the supplemental filing, the Department will submit a letter to the Commission recommending a comment period and whether any additional information is needed. After reviewing the Department's recommendation and recommendations from any other party, the Executive Secretary is authorized to set a reply comment period.	January 29, 2016 Supplement to the 2016-2030 Upper Midwest Resource Plan ("Supplement")
Order Point 2	As part of its January 29, 2016 supplement, Xcel shall file:	
	a. A rate impact analysis of the revised proposal;	Supplement Sections VI, Attachment E

Order Requirements

Order Point	Content of Order Point	Location of Order Point as Addressed in Supplement
	b. A copy of the "Y-2 Study" by the Midcontinent Independent System Operator (MISO) about the effects of shutting down one or two of the Sherco facilities;	Attachment D1
	c. An analysis of alternatives to all or part of the energy and capacity that would otherwise be provided by natural gas combined cycle and combustion turbine resources, including alternatives such as demand response, improved system or grid efficiencies, and distributed energy resources;	Attachment F
	d. A proposed method to acquire proposed combined cycle and combustion turbine resources (e.g., a Company-issued request for proposals, a certificate of need, or some other process);	Supplement Section V.C.
	e. Information about potential sites for any proposed combined cycle facility;	Supplement Sections I., V.A., V.B.1.,2. Attachment B
	f. If the site for the proposed combined cycle facility is known, the estimated total costs, including costs of any extension of natural gas service and transmission lines, along with the basis for choosing the site; and	Supplement Section V.B.
	g. Estimated total costs, including costs of any extension of natural gas service and transmission lines, for adding a combustion turbine in North Dakota by 2025.	Supplement Sections V.A., V.B., Attachment B

Order Requirements

Order Point	Content of Order Point	Location of Order Point as Addressed in Supplement
Order Point 3	If Xcel files a Sherco Conversion Plan Proposal, it shall do so no earlier than one month following the issuance of a Commission order ruling on the merits of Xcel's resource plan. In any such initial filing, Xcel shall include a suggested procedural schedule, following consultation with the MPCA.	Supplement Sections V.D., VIII.A.

Department of Commerce – Requested Information in November 6, 2015 Comments

DOC Comments Page No.	Inquiry	Location of Information as Addressed in Supplement
Page 3	A copy of the "Y2 Study" by the Midcontinent Independent System Operator (MISO) about the effects of shutting down one or two of the Sherco facilities as discussed on pages 7-8 of Xcel's October 2, 2015 Reply Comments;	Attachment D1
Page 3	Costs and options for addressing potential reliability concerns of Xcel's proposal, and expected timelines for the "additional study" noted above;	Supplement Sections V.A., V.B. Attachments D, D1, D2, D3
Page 3	A copy of MISO's declaration of Sherco Units 1 and 2 as System Stability Resources (as noted above) and whether that declaration applies to shutting down both facilities or only one;	See Company's response to Clean Energy Organizations' Information Request No. 79, Attachment B submitted November 9, 2015. Available at https://www.edockets.state.mn.us

Department of Commerce – Requested Information in November 6, 2015 Comments

DOC Comments Page No.	Inquiry	Location of Information as Addressed in Supplement
Page 3	Identification of the process required and options available to address a MISO declaration of a facility or facilities as System Stability Resources;	Supplement Sections V.B., Att. D
Page 3	The basis for building a combined cycle, natural gas generation facility "no later than 2026" given that no party in this proceeding has previously recommended adding a combined cycle plant prior to 2030, the significant level of "dump energy" on Xcel's system, and the preference for renewable energy resources in Minnesota Statutes;	Combined Cycle: Supplement Section V.A Dump Energy: Attachment B Renewables: Attachment B
Page 4	How the Company proposes to acquire the combined cycle and combustion turbine resources (a Company-issued request for proposals, a certificate of need, or some other process);	Supplement Sections V.C, V.D.
Page 4	Any information about potential sites for such a combined cycle facility;	Supplement Sections V.A., V.B.
Page 4	If the site for the proposed combined cycle facility is known, the estimated total costs, including costs of any extension of natural gas service and transmission lines, along with the basis for choosing the site;	Supplement Sections V.A., V.B.
Page 4	Estimated total costs, including costs of any extension of natural gas service and transmission lines, for "adding a combustion turbine in North Dakota by 2025."	Supplement Sections V.A., V.B.

Department of Commerce – December 17, 2015 Information Requests

IR No.	Inquiry	Disposition of Response to IR
DOC-66	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide an updated *.FSV file for the reference case used by the Company in the new supplement or confirm that the most recently provided *.FSV file remains valid.	Submitted in IR format via email and uploaded to eDockets.
DOC-67	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide macro files (*.INP) which adjust Xcel's reference case *. FSV file to implement the contingencies explored by the Company in the new supplement or confirm that the most recently provided *.INP files remain valid.	Submitted in IR format via email and uploaded to eDockets.
DOC-68	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide macro files (*.INP) which adjust Xcel's reference case *. FSV file to implement the scenarios explored by the Company in the new supplement or confirm that the most recently provided *.INP files remain valid.	Submitted in IR format via email and uploaded to eDockets.
DOC-69	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide the post-processing spreadsheets, if any, which adjust the Strategist outputs to match those reported by the Company in the new supplement. Please provide such post-processing spreadsheets for the base case in each scenario explored by the Company in the supplement.	Submitted in IR format via email and uploaded to eDockets.

Department of Commerce – December 17, 2015 Information Requests

IR No.	Inquiry	Disposition of Response to IR
DOC-70	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide a macro file (*.INP) which adjusts the reference case to retire the A.S. King power plant in 2027. As part of the macro file, please include any expected impacts on: • Variable operations and maintenance costs; • Fixed operations and maintenance costs; • On-going capital expenditures; and • Any other expected impacts. (See pages 11-12 of Xcel's March 16, 2015 supplement for background information on such adjustments). If such adjustments are better incorporated in a post-processing spreadsheet, please provide such a post-processing spreadsheet.	Pursuant to a January 25, 2016 conversation with the Department of Commerce, the Company will provide the requested information by February 26, 2016. Noted as such and submitted in IR format via email and uploaded to eDockets.
DOC-71	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide a discussion of the potential transmission impacts of retiring the A.S. King power plant in 2027, to the extent they are known.	Pursuant to a January 25, 2016 conversation with the Department of Commerce, the Company will provide the requested information by February 26, 2016. Noted as such and submitted in IR format via email and uploaded to eDockets.

Department of Commerce – December 17, 2015 Information Requests

IR No.	Inquiry	Disposition of Response to IR
DOC-72	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide a brief discussion of whether the generating unit shut down scenarios explored by the Company in the new supplement include the present value of the expected impact of an earlier shut down on depreciation expense and related rate base costs (return on equity, deferred taxes, and so forth).	Submitted in IR format via email and uploaded to eDockets.
DOC-73	Regarding the generating units at Monticello and Prairie Island, at the time Xcel files the January 29, 2016 supplement in this proceeding, please explain why the fixed cost input in the most recent Strategist database are lower than the non-fuel production expenses (subtracting line 20 from line 34) listed in Xcel's FERC Form 1 for 2014.	Submitted in IR format via email and uploaded to eDockets.
DOC-74	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide an estimate of the necessary retirement dates for Prairie Island units 1 and 2 under the assumption that substantial (over $40 million per year for the site) new capital expenditures do not occur starting in 2016.	Reference Supplement Section IV.D.1.

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Attachment B
Updated Strategist Modeling and Outputs

In addition to the summary provided in body of the Supplement document, this Attachment presents and explains detailing Strategist modeling analysis that supports our Current Preferred Plan. Included here are a description of the revised modeling assumptions, the scenarios and sensitivities analyzed, and the results of an economic analysis comparing the Present Value Revenue Requirements (PVRR) and Present Value of Societal Costs (PVSC) outputs for each scenario. We also respond here to the Department of Commerce's July 2, 2015 Comments related to the treatment of dump energy in our modeling.

I. REVISED MODELING ASSUMPTIONS

Our January 2, 2015 Initial Filing detailed the Planning Framework, Strategist Assumptions and Sensitivities, and Scenarios Analyzed that formed the basis of our resource planning analysis. The updates and additional modeling presented in this Supplement build on all the planning analysis done since initially filing this Resource Plan. We clarify that we made no changes to our base assumptions, such as our underlying sales and natural gas price forecasts.

Our March 16, 2015 Resource Plan Supplement forms the basis of the analysis supporting the Current Preferred Plan we present in this Supplement. Two key changes that have occurred since the March 2015 Supplement and the October 2015 Reply filing are the extension of federal tax credits for renewable energy and the growth in our Community Solar Garden forecast. In the narrative below, we explain the impact to our Current Preferred Plan of these changes on our resource additions and the associated costs.

We have included the impacts of the tax credit extension in all of our economic analysis of our Current Preferred Plan, to incorporate the changed circumstances related to renewable energy costs. We have outlined the impact of the small solar adjustments to in the section below, but have not reflected those cost changes in the PVRR and PVSC comparisons in Section III below. As these changes are the result of policy recommendations outside the scope of our Current Preferred Plan, we felt it was appropriate to include only those resource changes proposed in our plan, in our cost impact analysis. Although we did not submit a detailed economic analysis with our October 2015 revised proposal, we note that the extension of the Production Tax Credit (PTC) and Investment Tax Credit (ITC) reduces the PVRR of our Current

Preferred Plan by $202 million; the changes to the small solar increases the PVRR by approximately $760 million.

A. Tax Extender (PTC, ITC) Updates to Wind and Solar Prices

Legislation was enacted in December 2015 that extended the availability of PTCs (primarily relating to wind projects) to 2019 and the 30 percent ITC (primarily related to solar projects) to 2022. The Consolidated Appropriations Act of 2016 also provided step downs in tax incentives in various years depending on the type of project and the date construction commences and/or the project is placed into commercial operation.

To incorporate these changes into the modeling, it was necessary to develop updated pricing for wind and solar for the varying tax levels, as well as develop additional alternatives to capture the year-by-year changes. In developing these new alternatives, it was assumed that the Internal Revenue Service will ultimately promulgate a safe harbor memorandum for the new law that has similar timing requirements related to construction start and in-service dates as the current memorandum (i.e. approximately two years of construction time allowed for safe harbor). The assumptions used are shown below in Table 1.

Table 1: Wind and Solar Tax Benefit Assumptions

Construction Start	COD, by End of:	First Full Year of Ops	PTC	ITC
2016	2018	2019	100%	30%
2017	2019	2020	80%	30%
2018	2020	2021	60%	30%
2019	2021	2022	40%	30%
2020	2022	2023		26%
2021	2023	2024		22%
2022	2024	2025		10%

The pricing for each alternative was developed in the same manner as described in the Appendix to the March 16, 2015 Resource Plan Supplement document, using a spreadsheet financial model to convert an owned project to Power Purchase Agreement (PPA) equivalent pricing. For the Current Preferred Plan that includes owned renewables, the original ownership revenue requirements were used, resulting equivalent costs on a net present value basis of owned vs. PPA projects for a given tranche. The PPA equivalent pricing is shown below in Table 2.

Table 2: PPA Equivalent Pricing for Wind and Solar ($/MWh)

Tech Type:	Solar	Solar	Solar	Solar	Solar	Solar	Wind	Wind	Wind	Wind
Construction Start:	2016	2018	2019	2020	2021	2022+	2016	2017	2019	2020+
First Full Year of Ops:	2019	2021	2022	2023	2024	2025+	2019	2020	2022	2023+
Tax Benefit:	30% ITC	30% ITC	30% ITC	26% ITC	22% ITC	10% ITC	100% PTC	80% PTC	40% PTC	0% PTC
2019	67.30						21.98			50.78
2020	68.80						22.48	26.78		51.92
2021	70.35	69.54					22.98	27.38		53.08
2022	71.92	71.09	69.73				23.49	27.99	37.87	54.27
2023	73.53	72.69	71.29	70.96			24.02	28.62	38.72	55.49
2024	75.18	74.31	72.89	72.55	72.20		24.56	29.26	39.58	56.73
2025	76.86	75.98	74.52	74.18	73.82	95.00	25.11	29.91	40.47	58.00
2026	78.58	77.68	76.19	75.84	75.47	95.00	25.67	30.58	41.38	59.30
2027	80.35	79.42	77.90	77.54	77.16	95.00	26.25	31.27	42.30	60.63
2028	82.14	81.20	79.64	79.28	78.89	95.00	26.83	31.97	43.25	61.99
2029	83.98	83.02	81.43	81.05	80.66	95.00	27.44	32.68	44.22	63.38
2030	85.87	84.88	83.25	82.87	82.46	95.00	28.05	33.42	45.21	64.80
2031	87.79	86.78	85.12	84.72	84.31	95.00	28.68	34.17	46.22	66.25
2032	89.76	88.72	87.02	86.62	86.20	95.00	29.32	34.93	47.26	67.73
2033	91.77	90.71	88.97	88.56	88.13	95.00	29.98	35.71	48.32	69.25
2034	93.82	92.74	90.97	90.55	90.10	95.00	30.65	36.51	49.40	70.80
2035	95.92	94.82	93.00	92.57	92.12	95.00	31.34	37.33	50.51	72.39
2036	98.07	96.94	95.09	94.65	94.19	95.00	32.04	38.17	51.64	74.01
2037	100.27	99.12	97.22	96.77	96.30	95.00	32.76	39.02	52.80	75.67
2038	102.52	101.34	99.39	98.94	98.45	95.00	33.49	39.90	53.98	77.36
2039	104.81	103.61	101.62	101.15	100.66	95.00	34.24	40.79	55.19	79.09
2040	107.16	105.93	103.90	103.42	102.91	95.00	35.01	41.70	56.42	80.87

This extension provides material reductions in the cost of renewable energy acquisitions proposed in our each of our Resource Plan scenarios. We have therefore adjusted our proposed wind additions in 2020 to be PTC-eligible in all scenarios analyzed in this Supplement, to allow for an apples-to-apples comparison between the plans. These changes were made to all scenarios in order to reflect how the current law impacted changing individual plans differently and therefore changes the delta analysis of the various plans.

The impact of this change on our Current Preferred Plan is a decrease in the overall PVRR of $202 million and a decrease in the overall PVSC of $203 million.

B. Small Solar Forecast Update

We launched our Solar*Rewards Community program in December 2014. As we have previously noted, we received an overwhelming response to our program – receiving nearly two thousand applications to-date. Modeling data regarding distributed solar was developed for the January 2, 2015 Initial Filing prior to the Company or Commission finalizing the tariffs and program offerings for individual distributed solar or community solar gardens installations. Subsequent to development of the initial models, the regulatory structure for distributed solar has become much clearer. We have more information on issues in the Community Solar Gardens proceeding (Docket No. E002/M-13-867) that were previously unresolved, and have therefore been able to update our forecast for purposes of this Supplement.

The initial data for cost and payment terms was estimated by the Company using its experience in other jurisdictions, primarily Colorado. In the Initial Filing, and carried forward into the Supplemental filing in March 2015, the assumption used was payments for 10 years at 8¢/kWh. Due to the magnitude of the solar programs proposed and modeled in these scenarios, the cost assumptions should be adjusted closer to current practice. In the alternative analysis with the small solar forecast adjustment discussed here, the costs and payment terms have been revised to payments for 20 years at 12¢/kWh.

In Table 3 below, we have accelerated the addition of small solar resources – a total of 422 MW in the pre-2020 timeframe in anticipation of the completion of several Solar*Reward Community projects and continuing our commitment to growing renewable resources.[1] While the current project pipeline for community solar gardens

[1] We adjusted our forecast for small solar, including community solar gardens and distributed generation (DG) in this Supplement based on a mixture of regulatory adjustments, detailed design, and project movement in the pipeline for our Solar*Rewards Community program.

exceeds this projection, we anticipate that some projects will experience difficulties in permitting, financing, or interconnection, therefore never reaching full operation.

Although the ITC has been extended, we believe that a majority of projects will be completed in the next year for the Solar*Rewards Community program based on established financing. Therefore, we have forecasted 259 MW of projects reaching operation by the end of 2016, and lowered the forecast after this time. Table 3 below shows the impact this adjusted small solar forecast has on our capacity/deficit position from the L&R analysis in the Supplement document.

Table 3: Small Solar Forecast Adjustment (MW) ICAP

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Current Preferred Plan – Proposed Solar Additions																
Small Solar Additions	42	45	49	53	58	17	20	24	29	34	41	49	59	71	85	675
Large Solar Additions	0	0	0	200	0	200	100	100	200	100	100	0	400	0	0	1,400
Total Additions by Year	42	45	49	253	58	217	120	124	229	134	141	49	459	71	85	2,076
Current Preferred Plan – Alterative Analysis w/Small Solar Forecast adjustment																
Small Solar Additions	259	159	91	83	76	17	20	24	29	34	41	49	59	71	85	1,097
Large Solar Additions	0	0	0	200	0	200	100	100	200	100	100	0	0	0	0	1,000
Total Additions by Year	259	159	91	283	76	217	120	124	229	134	141	49	59	71	85	2,097
Impact of Small Solar Forecast Adjustment on Current Preferred Plan																
Increased Small Solar	217	114	43	31	18	0	0	0	0	0	0	0	0	0	0	422
Adjusted Large Solar	0	0	0	0	0	0	0	0	0	0	0	0	-400	0	0	-400
Change in Total Additions by Year	217	114	43	31	18	0	0	0	0	0	0	0	-400	0	0	22

The impact of this adjusted small solar forecast is a shift in the type and timing of solar additions in our plan, which impacts the overall cost of the Current Preferred Plan. In order to accommodate the increase to the small solar forecast in the early years of the plan, the utility-scale solar additions we propose in our Current Preferred Plan would be reduced. As Table 3 above shows, we would remove the remaining 400 MW of utility-scale solar in the plan in 2028 at a fixed flat price of $95/MWh in order to add the more than 400 additional MW of small solar between 2016 and 2020 at a fixed flat price of $120/MWh. While this change does not significantly impact the net solar additions in the plan, it accelerates the installation of the solar, but would also increase the cost of the plan by moving to a different, less cost-effective form of solar.

The impact of this change is an increase in the overall PVRR of our Current Preferred Plan by approximately $759 million. The PVSC impact of this change on our Current Preferred Plan is an increase of $737 million.

C. Updated Nuclear Forecast

Certain fixed costs that do not affect the relative economics of plans being considered are typically not included in the Strategist database. As an example, costs related to the distribution and corporate services business areas, transmission costs not related to generation plans, and recovery of current ratebase for owned units that are not subject to change are not typically included in the model. Strategist does include all costs related to the operations of owned and PPA units (fuel, variable and fixed O&M, PPA payments), and the models used for this resource plan do include future capital expenditures and recovery of ratebase for the Sherco units, as the costs for Sherco vary among the different retirement scenarios. In total, the Strategist model represents about 46 percent of the total system revenue requirements that go into rates, with the other 54 percent being unrelated to decisions around resource selection or planning.

In an effort to provide increased transparency around our nuclear cost assumptions, we have elected to include an analysis of scenarios with the full costs of nuclear in the Scenario Outcomes below. We have updated the model for that analysis to include specific forecasted Capital and Fixed O&M (FOM) costs for the planning period for the Monticello and Prairie Island units.

The O&M costs that were in the model previously for those units have been updated to the most recent estimate of future O&M. In addition, costs that were not in the model previously related to future capital expenditures and recovery of current rate base were added to the model. The net results of adding these costs in, as well as the much lesser impact of adjusting the O&M forecast, results in an increase in the net present value of revenue requirements (or societal cost) that Strategist reports of around $3.6 billion. We clarify that this total Capital and FOM cost is not the "increase" in our nuclear cost forecast that we discussed in our October 2, 2015 Reply Comments; we discuss the $600-$900 million forecasted cost increase in Section VII of the Supplement document.

This does not result in an increase to the relative cost of any plan, but simply adds in costs that were never reported before. Essentially, Strategist was adjusted from reporting 46 percent of total system costs to around 51 percent of total system costs and, as the same adjustment was made to all plans, the delta in costs between the various plans is unchanged. The impact of these adjusted cost assumptions to the overall PVRR/PVSC of the modeling scenarios is shown below in Section VII on Table 10.

II. SCENARIOS AND SENSITIVITIES SUMMARY

A. Scenario Summary

To analyze our Current Preferred Plan, we included five key scenarios from our previous Resource Plan filings. Each of these scenarios was updated with the assumptions described above. 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.

1. Updated Previous Scenarios

Each of the scenarios described below used the baseline data from our March 2015 Supplemental filing, updated with the relevant modeling assumption revisions described above.

- *Reference Case:* Includes the continued operation of Sherco Units 1 and 2 through 2030, 400 MW of wind additions, over 400 MW of small solar additions, 287 MW of large solar additions, no assumptions changes.
- *Updated 2015 Plan:* Includes the continued operation of Sherco Units 1 and 2 through 2030, 1,800 MW of wind additions, over 1,600 MW of large solar additions, nearly 700 MW of small solar additions, updated for Federal ITC/PTC.
- *North Dakota Plan:* Consistent with March Supplement, contains no additional renewables beyond currently committed 750 MW of wind, no assumptions changes.

2. Current Preferred Plan and Variants

The scenarios below reflect the Current Preferred Plan, with various alternatives for replacement capacity of the Sherco unit retirements. We allowed the model to select both site-specific and generic replacement capacity alternatives for the Sherco units. The modeling of the site-specific alternatives is discussed in detail in Section V of the Supplement.

- *Current Preferred Plan*: Cease operation of a total of 1,400 MW of capacity and associated energy at Sherco Unit 2 in 2023 and Unit 1 in 2026, 1,800 MW of wind additions, over 1,400 MW of large solar additions, nearly 700 MW of small solar additions, updated for Federal ITC/PTC extension, goal of 50 percent ownership of renewables, Company-owned Fargo CT and Sherco CC.

- *Current Preferred Plan – All Generics*: Same as Current Preferred Plan, but with all generic thermal alternatives. Leave behind costs for not replacing generation at the Sherco site are not modeled within Strategist so are not included in the PVSC/PVRR's, but are calculated outside of models. Updated for tax credit extension.

3. Full Optimization Scenarios

We performed an unconstrained optimization incorporating the option of adding incremental Demand Response and Distributed Energy Resources.

- *Resource-Need Optimization:* Unconstrained optimization simultaneously filling energy and capacity needs.
- *Capacity-Need Optimization:* Unconstrained optimization filling capacity needs only.

The results of this analysis are included in Attachment F. A summary of the primary scenarios included in this Supplement is shown in Table 4 below.

Table 4: Summary of Scenarios Analyzed in this Supplement

Primary Sherco / Carbon / Renewable Alternatives	Strategist Output Code
Continued Operation (Run Both Units to 2030)	
Reference Case	1
Updated 2015 Plan	
Updated 2015 Plan - PTC Wind in 2020	10
North Dakota Plan	
Original North Dakota Plan - No additional renewables beyond currently committed	15
Current Preferred Plan	
Current Preferred Plan - Retire Sherco 2023 and 2026, accelerate renewables, Sherco CC, Fargo CT	28
Current Preferred Plan with all generic thermal replacements, excluding leave behind costs	28_A

B. Sensitivity Summary

To determine how changes in our assumptions impact the costs or characteristics of different Resource Plans, we examined 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 could conceivably 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 a subset of the same sensitivity cases that were used in the January 2, 2015 Initial and March 16, 2015 Supplemental Filings, selecting the sensitivities that are most relevant to the decisions being contemplated and that are of the most interest to the various parties to this case. Additionally, what was referred to as the "Traditional View" in the March 2015 Supplement (Sensitivity "R", Do Not Maintain CAPCON Length) is incorporated into all cases and is no longer considered a sensitivity.

Table 5 below gives a summary of the Modeling Sensitivities included in this Supplemental filing.

Table 5: Modeling Sensitivities

Base CO_2 (Mid) Costs	**Strategist Output Code**
Low Gas Prices	C
High Gas Prices	D
Zero CO_2 Costs	
No Regulated CO_2 (Contains Externality CO_2)	K
ND Assumptions (No Extern, No CO_2 Costs)	T
"Customer impact" (No Cap Credit, No Extern, No CO_2 Costs)	U
Other CO2 Sensitivities	
CO_2 \$9, Start 2019	L
CO_2 \$34, Start 2019	M
CO_2 \$9, Start 2024	N
CO_2 \$34, Start 2024	O
CO_2 at Federal SCC 3%	P

III. ECONOMIC ANALYSIS

After identifying the scenarios and sensitivities to update for this Supplement, we performed an updated resource planning analysis in largely the same manner we used for both our Initial Filing and our March 16, 2015 Supplement. To provide a comparison between the various cases we considered, we use a traditional resource planning method and rank the scenarios based on cost. In addition to a least-cost analysis, we perform a more holistic analysis to determine if our Current Preferred Plan is appropriately balanced within our planning framework when compared to the other scenarios.

We analyze the economics of the scenarios in both PVRR and PVSC terms. The PVSC results provide a baseline ranking of the overall societal benefits of each of the scenarios analyzed – applying the Minnesota Commission's regulatory cost of carbon dioxide and externalities values for criteria pollutants – and the externality for carbon in non-regulated years in the modeling period of 2015-2053. The PVRR-based analysis excludes carbon costs and all externalities values over the modeling period.

Because actual customer cost impacts are a key consideration within our planning framework, and due to the fact that not all of the NSP System states allow for an analysis that includes carbon costs or externalities, we also perform a least-cost analysis on a PVRR basis (North Dakota Plan). We present the results of these analyses in this section, and demonstrate that our Current Preferred Plan provides the most reasonable outcome under both a least-cost analysis and under a more comprehensive analysis.

1. *Traditional Resource Planning Analysis*

We first analyzed our modeling outputs on a PVSC basis to determine the least-cost plan including societal impacts. Table 6 below provides the PVSC outcomes for each of the key scenarios we analyzed for this Supplement.

Table 6: PVSC Results ($Millions)

Scenarios	PVSC Results
Current Preferred Plan	$51,293
Current Preferred Plan, All Generics	$51,280
Updated 2015 Plan	$51,458
Reference Case	$52,422
North Dakota Plan	$52,620

As shown above in Table 6, our Current Preferred Plan is the second lowest cost plan on a PVSC basis. Only the Current Preferred Plan with a generic Sherco Unit replacement ranks higher on a PVSC basis – with a minimal $13 million difference in PVSC. This difference is due to the exclusion of leave-behind costs for not replacing generation at the Sherco site, which are not modeled in Strategist.

Table 7 below provides the PVRR rankings of the same key scenarios.

Table 7: PVRR Results ($Millions)

Scenarios	PVRR Results
Current Preferred Plan	$45,606
Current Preferred Plan, All Generics	$45,582
Updated 2015 Plan	$45,302
Reference Case	$45,605
North Dakota Plan	$45,473

From a strictly PVRR perspective, as Table 7 above shows, the Reference Case is the lowest-cost plan. Table 7 also indicates that the North Dakota Plan ranks the next best on a PVRR basis, since it relies heavily on natural gas generation additions as compared to the Preferred or Current Preferred Plans. As we have mentioned previously, we do not believe that either of those plans would meet Clean Power Plan (CPP) compliance. Our Current Preferred Plan, with variations for site-specific and generic replacements for Sherco capacity, has the lowest PVRR ranking, as the benefits of the carbon emissions impacts of the plan are not captured in a PVRR analysis. A full matrix of PVRR and PVSC results is included in Section VII below.

After performing the PVSC and PVRR analyses, we evaluate the scenarios more holistically by analyzing their environmental performance, strategic flexibility, and cost. Table 8 below, the Run Key carries forward the PVSC and PVRR ranking of each scenario to provide a reference point for the broader analysis, but it also identifies key policy outcome metrics such as amount of CO_2 emissions reductions from 2005 levels and the amount of renewable energy added to the NSP System under each scenario.

Table 8: Run Key[2]

	PVSC Results ($M)	PVRR Results ($M)	2030 Coal Gen vs. Ref. Case	2030 Gas Burn (Bcf)	2030 Percent CO_2 Reduction	Total Expansion Plan Renewable Additions (MW)	CPP Compliant?
Current Preferred Plan	$51,293	$45,606	-59%	83	58%	3,200	Yes
Current Preferred Plan, All Generics	$51,280	$45,582	-59%	84	57%	3,200	Yes
Updated 2015 Plan	$51,458	$45,302	-16%	32	42%	3,200	Uncertain
Reference Case	$52,422	$45,605	-	58	23%	400	No
North Dakota Plan	$52,620	$45,473	+3%	68	19%	0	No

The comprehensive Run Key analysis shows that our Current Preferred Plan has the stronger performance in terms of carbon reductions and renewable energy additions to the NSP System. The renewable energy additions in our Updated 2015 Plan and Current Preferred Plans are consistent, but the timing and ownership has shifted, as shown in our Expansion Plans. This plan continues to provide the best value for our customers – achieving a balance between multiple objectives, including: reasonable costs, dramatic emissions reductions, anticipated compliance with the CPP, and maintaining reliability on our system. Our Current Preferred Plan proposes to time these resource changes such that we minimize the socioeconomic and technical impacts by allowing sufficient time to plan for fleet transitions.

IV. ALTERNATIVE SCENARIOS CONSIDERED

As part of the process of developing our Current Preferred Plan, we evaluated a broad range of alternatives. Our updated Strategist modeling included consideration of several alternative scenarios, including conversion of a Sherco Unit to a Boiler, and solar and wind resources in addition to generic and site-specific CT and CC alternatives. Here, we discuss these alternative Scenarios in greater detail.

[2] In this Run Key Table, the PVRR Results, change in coal generation in 2030 as compared to the Reference Case (2030 Coal Gen vs. Ref Case), amount of gas burned at our plants in 2030 in Billions of cubic feet (2030 Gas Burn (Bcf)), and the percent reduction of CO_2 from 2005 levels (2030 Percent CO_2 Reduction) are all considered under a cost sensitivity that excludes regulatory costs and CO_2 externalities in the dispatch. Under this sensitivity, there will be a tendency to overestimate CO_2 emissions, as coal would be 'priced' at a lower cost and the likelihood of dispatching the resource more frequently would therefore be increased.

2. Conversion of a Sherco Unit to Gas

As noted above, one unit at Sherco could be converted to a gas boiler, as the Department recommended in its July 2, 2015 Comments. We commissioned an external study of impacts and costs for converting either of Sherco Units 1 or 2 boilers to gas-fired and to evaluate the economic aspects of such a conversion. We note that a gas-fired boiler would be a capacity resource only, as the technical limitations of a long start-up time, a slow ramp rate, high O&M, and a high heat rate as compared to gas fired turbines would likely result in very low annual capacity factors of less than two percent due to the Unit's economic dispatch order position. Compared to our Current Preferred Plan, replacing a unit at Sherco with a gas boiler and adding a CC increases the PVSC by $36 million dollars.

In addition, continued operation of a large coal boiler that is converted to utilize gas also results in a number of operational issues. While the unit can be counted as a capacity resource after conversion, we believe that in order to qualify as a capacity resource in the Midcontinent Independent System Operator's (MISO) evolving capacity construct, firm gas supply may be required. The current capacity construct in MISO is on an annual basis from June 1 to May 31. If MISO changes to a seasonal capacity construct, firm gas may not be required during the summer season. However, as one Sherco unit is a large portion of the entire system capacity, it may not be practical from an operations perspective to have the unit available for only part of the year. In addition, the operating characteristics of the large unit that was designed for base load operation will push it to near the bottom of the dispatch order even with low gas costs being directly competitive with coal, if not better.

A converted gas unit would have a ramp rate of approximately 5 MW per minute from a minimum load level of 260 MW to full load. This is considerably slower than a CT, which has a ramp rate of approximately 10 MW per minute. We would expect that when the unit is dispatched it could be kept online for several days in order to cover the start costs, anticipated to be approximately $100k for labor plus 3,500 to 4,000 MMBTU of start fuel. Once taken through and orderly shut-down the unit will not be available for restart for at least one to two days.

3. All Renewables

We also considered replacing the capacity and energy from retirement of Sherco Units 1 and 2 with replacement of the capacity and energy entirely from renewable sources, as is required under Minn. Stat. § 216B.2422, subd. 4. Our Current Preferred Plan includes 1200 MW of renewable additions by 2020. However, in addition to the significant amount of renewable generation we plan to add to our system, gas-fired generation plays an important role on the system and was also selected as a cost-effective resource addition to meet customer needs.

Variable resources such as wind and solar must be integrated with dispatchable gas-fired generation in order to ensure adequate system reliability. Gas-fired generation will likely be distributed at several locations around the NSP System to provide grid support and to efficiently utilize existing transmission infrastructure. If replacement generation is not located at the Sherco site, we would need to otherwise resolve a voltage deficiency in the Becker, Minnesota area and for the Monticello nuclear plant, which would require the conversion of one of the Sherco units to a synchronous condenser, a Static Var Compensator (SVC) or Statcom device.

The goal of a sustainable, cleaner energy future depends upon sufficient infrastructure to support delivery of utility-scale and distributed renewable resources. In particular, modernized transmission and distribution systems are critical to meet the challenges of emerging technologies, expanding renewable policies, and a comprehensive view of resource planning. Appendix H of our initial filing discussed some of the effort undertaken at both the transmission and distribution level to ensure increased levels of renewable generations can be accommodated.

V. TREATMENT OF DUMP ENERGY

As the Department noted in their July 2, 2015 Comments, our modeling shows a significant level of dump energy. In Strategist, DSM, wind, and solar are modeled as must-run resources and their generation is used to reduce customer load prior to performing thermal dispatch. The thermal dispatch includes several must-run units, such as large coal plants, as well as must-take PPAs, such as biomass. There are hours during which the modified load (customer load less DSM, wind, and solar generation) is less than the minimum physical operating level of the must-run thermal resources. Strategist reports the energy when generation is greater than load as dump energy. Dump energy occurs because Strategist does not allow the must-run thermal units and must-take PPAs to reduce their generation to balance load. The Department correctly explained in its comments that dump energy increases as more wind resources are added to the system. This occurs because the modified load will decrease as wind additions are increased. This results in more instances where the modified load is less than the must run thermal resources and there is a corresponding increase in dump energy.

In our analyses we assign a revenue credit to dump energy equal to 50 percent of the market energy price. In addition, by requiring the thermal units to operate at their minimum, the costs and emissions for the thermal generation related to the dump energy are included. Dump energy does not impact the optimization of the expansion plans or the dispatch of the generators in the model. We assigned the revenue credit outside the model after the optimization and dispatch is complete. We believe this modeling approach is appropriate and provides for the full value of wind to be accounted for, as it allows all the energy available from both wind and thermal units to be included in the analysis.

It is also important to note that over-builds would be immediately apparent if the reserve margin significantly exceeded the required reserve margin. This does not occur in our modeling. We conclude that our approach provides a consistent comparison of renewable and thermal resources.

The Department has also expressed concern that dump energy may indicate there is excess energy that can be applied to reduce the resource additions needed to meet customer load. Dump energy typically occurs, however, during low-load or off-peak periods. While the resources available during these low load periods may greater than the resources needed to serve these lower loads, it is not possible to "save" this energy and use it later when loads are higher.

Finally, as the Department noted, dump energy is a challenging issue from both a cost and CO_2 perspective. We propose to work with the Department to arrive at an agreed-upon methodology.

VI. LONG-TERM RATE IMPACT METHODOLOGY

Figure 5 in the body of the Supplement illustrates the estimated cost impact of our proposal over the course of the planning period. To calculate these long-term rate impacts of the Current Preferred Plan as compared to the Reference Case, we first developed a forecast of total rates through 2020 under the Reference Case assumptions. To do this, we used a combination of the Company's shorter range financial forecasts and a special-purpose Strategist model used to project total system revenue requirements for extended periods.

Typically, the Strategist model develops projections for generation-related costs. To derive a total system (including transmission, distribution, A&G, etc.) forecast, we expanded the standard Strategist model by adding capital and expense items associated with the other costs that are not typically modeled. We input starting net plant and deferred tax balances, capital spend forecasts and O&M forecasts for the existing generation, transmission, distribution and overhead business areas, and calibrated the model such that the total revenue requirements through 2020 approximately tracked the more refined short-term financial forecasts during those years.

Developing a total rate forecast beyond 2020 when detailed company financial models are not available would depend on making assumptions for capital expenditures and O&M expenses for all areas of the business, including generation (both new and existing), transmission, distribution and corporate support services. Many of these assumptions would be highly speculative, and the resulting total rate forecast would be similarly speculative. As discussed in this Attachment in describing the modeling changes for the nuclear fleet, Strategist normally models only the generation-related portion of the business, or around 50 percent of the total revenue requirements. For the period beyond 2020, the costs not typically modeled in Strategist were escalated at a generic "inflation-proxy" rate of 2 percent, and were added to the annual costs from the IRP Scenario 1 (Reference Case) model results that are presented throughout this filing. This approach avoids speculation on areas of the business not related to resource planning, while preserving the detailed generation-related information from the Strategist model.

The annual deltas of the various scenarios (including the Updated 2015 Plan and the Current Preferred Plan) to the Reference Case were added to this underlying Reference Case total rate forecast to determine the total rates for these scenarios.

VII. SCENARIO OUTCOMES

An updated summary of the Strategist model's PVRR/PVSC outputs for the various scenarios and sensitivities is shown below in Table 9. Table 10 below shows the results including the nuclear cost assumptions described in Section I, Part C above.

Table 9: PVSC/PVRR Total ($M) for all Scenarios/Sensitivities

Scenarios	Number	Base	LOW GAS PRICE C	HIGH GAS PRICE D	ZERO CO2 K	LOW CO2 L	HIGH CO2 M	LATE LOW CO2 N	LATE HIGH CO2 O	SOCIAL COST OF CARBON P	ND ASSUM-PTIONS T	CUSTO-MER IMPACT U
Reference Case	1	52,422	49,050	57,073	47,587	48,781	55,882	48,320	53,235	66,308	45,605	45,934
Original 2015 Plan	10_A	52,083	49,225	56,063	47,755	48,818	55,193	48,386	52,663	64,863	45,924	46,229
Updated 2015 Plan	10	51,458	48,599	55,439	47,132	48,195	54,568	47,763	52,040	64,237	45,302	45,606
Current Preferred Plan (no Boiler)	28	51,293	48,283	55,463	47,317	48,293	54,155	47,896	51,805	63,457	45,606	45,956
Current Preferred Plan, All Generics, No Leave Behind Cos	28_A	51,280	48,261	55,465	47,295	48,273	54,148	47,876	51,797	63,464	45,582	45,934
Current Preferred Plan (Boiler + SHC CC x1)	B28	51,329	48,319	55,499	47,352	48,328	54,191	47,931	51,841	63,492	45,641	45,995
North Dakota Plan	15	52,620	49,013	57,568	47,535	48,792	56,252	48,305	53,464	67,051	45,473	45,761

Table 10: PVSC/PVRR Total ($M) for all Scenarios/Sensitivities with Nuclear Costs

Scenarios	Number	Base	LOW GAS PRICE C	HIGH GAS PRICE D	ZERO CO2 K	LOW CO2 L	HIGH CO2 M	LATE LOW CO2 N	LATE HIGH CO2 O	SOCIAL COST OF CARBON P	ND ASSUM-PTIONS T	CUSTO-MER IMPACT U
Original Reference	1	56,033	52,662	60,684	51,199	52,393	59,494	51,932	56,847	69,919	49,217	49,545
Original 2015 Plan	10_A	55,694	52,836	59,675	51,367	52,430	58,805	51,997	56,274	68,474	49,536	49,840
Updated 2015 Plan	10	55,070	52,211	59,051	50,743	51,806	58,179	51,374	55,652	67,848	48,913	49,218
Current Preferred Plan (no Boiler)	28	54,904	51,895	59,074	50,929	51,905	57,766	51,508	55,417	67,069	49,218	49,567
Current Preferred Plan, All Generics, No Leave Behind Cos	28_A	54,891	51,873	59,076	50,907	51,885	57,760	51,488	55,409	67,075	49,193	49,546
Current Preferred Plan (Boiler + SHC CC x1)	B28	54,940	51,931	59,110	50,964	51,939	57,802	51,543	55,453	67,103	49,253	49,607
Original ND Plan	15	56,231	52,624	61,180	51,146	52,403	59,864	51,916	57,076	70,663	49,085	49,373

Attachment C
Resource Plan Comparisons

As our Resource Plan has evolved substantially since our initial January 2015 filing, we provide here a comparison and update on the Expansion Plans for our Reference Case, Updated 2015 Plan, and Current Preferred Plan, to provide readers an easy reference between the scenarios. We have also included data on our updated Renewable Energy Standard (RES) and Solar Energy Standard (SES) Compliance positions under the Current Preferred Plan.

A. Expansion Plans

The Expansion Plans below represent only those resource additions we are proposing in each scenario. The Updated Load and Resources Table in the body of the Supplement included all of the existing and approved resource changes that we anticipate over the course of the planning period. Table 1 below provides our Reference Case Expansion Plan.

Table 1: Reference Case Expansion Plan – Installed Capacity (ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Wind	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	400
Combustion Turbine	-	-	-	-	-	-	-	-	-	-	690	690	460	-	-	-	1,840
Combined Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	778

Only the utility-scale resource additions proposed as part of our Reference Case are identified in Table 1. All small solar, as well as the 187 MW Solar Request for Proposals Portfolio[1] and the competitive acquisition process[2] (CAP) resources, are reflected as existing/approved resources, and therefore not included in the Expansion Plans. The 400 MW of wind in 2020 represents non-Production Tax Credit (PTC) additions, as we did not update the Reference Case to include the tax credit extension.

Table 2 below shows the Expansion Plan for our Updated 2015 Plan, referred to in previous filings as the Preferred Plan.

[1] Approved by the Commission in February 2015 in Docket No. E002/M-14-162.
[2] Docket No. E002/M-12-1240, includes 100 MW Aurora Solar project, 345 MW Calpine Mankato project, and the 232 MW Xcel Energy Black Dog 6 project.

Table 2: Updated 2015 Plan Expansion Plan (ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	-	-	-	-	-	-	300	200	200	500	-	200	1,400
Wind	-	-	-	-	-	600	-	-	200	-	600	-	400	-	-	-	1,800
Combustion Turbine	-	-	-	-	-	-	-	-	-	-	460	460	230	230	-	-	1,380

The Updated 2015 Plan Expansion Plan is largely consistent with what we filed in the March 2015 Supplement, although the assumptions have been updated to reflect the extension of renewable energy tax credits. As a result, the 600 MW of wind in 2020 is modeled as benefiting from the PTC. Finally, the Current Preferred Plan Expansion Plan is included in Table 3 below.

Table 3: Current Preferred Plan Expansion Plan (ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800
CT	-	-	-	-	-	-	-	-	-	-	460	690	230	230	-	230	1,840
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	230
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	786

This Expansion Plan for the Current Preferred Plan matches the total proposed renewable resource additions included in our October 2, 2015 Reply. The updated assumption related to the renewable energy tax credit extension results in a shift in the type – from non-PTC to PTC – and timing of those resources, and an associated cost reduction for the 800 MW of wind added in 2019. Our October proposal included a proposed generic North Dakota CT in 2023, which after further analysis has shifted to a Company-owned CT in Fargo in 2025, although the unit may be placed in-service before 2025. Due to the site-specific resource additions we have selected for our Current Preferred Plan, the model's selection of natural gas capacity additions have adjusted. While a Sherco boiler conversion was considered in our October Reply Comments, it was not selected in our Current Preferred Plan for reasons discussed in Attachment B. Of note, the retirement of the Sherco units result in the need for additional CT capacity and the addition of a combined cycle in 2027.

B. Renewable Energy Standard Compliance Position

Our Current Preferred Plan continues to support and exceed our compliance through 2030 with the Renewable Energy Standard (RES) and objectives across the NSP system that we presented in our January 2015 filing. Minnesota's RES requires the Company to generate or procure 30 percent of retail electric sales from renewable sources by 2020.[3] This scenario assumes the 3,900 MW of renewable energy additions laid out in our Current Preferred Plan and includes: 700 MW of small solar, 1,400 MW of large solar, and 1,800 MW of wind. Table 4 below details our compliance position through the generation of Renewable Energy Credits (RECs) with NSP System RES obligations in 2016 and 2020.

Table 4: Renewable Energy Standard Compliance, Current Preferred Plan

	2016	2020
NSP Calendar Year RECs	11,216,449	17,274,331
NSP RECs Available for Compliance	26,887,161	55,532,748
RECs Needed for Compliance	8,833,247	10,917,122

In our Current Preferred Plan, we expect to generate sufficient RECs to exceed the renewable energy obligations of those states in the NSP system.

C. Solar Energy Standard Compliance Position

The SES requires an additional 1.5 percent of retail sales to come from solar energy resources by 2020. Of the 1.5 percent SES, 10 percent must come from systems with capacity less than 20 kW.

Table 5: Solar Base Case

	2020
S-RECs Needed for SES Compliance	453,483
S-RECs Available to Meet Requirement	4,620,918
Total Compliance Energy	1,396,551

Table 5 above demonstrates that in our Current Preferred Plan, the 1,400 MW of additional utility-scale solar energy in the out-years of the planning period combined with the small solar and community gardens additions take us beyond our SES compliance obligations, and put us on a path toward fulfillment of Minnesota's energy policy vision.

[3] Minn. Stat. § 216B.1691.

Examining the Grid Impacts of Retiring Sherco Units 1 and/or 2

A Grid Primer and Summary Report of:

Midcontinent Independent System Operator (MISO) Attachment Y2 Study performed by: MISO (August 28, 2015)

Xcel Energy Transmission Reliability Study performed by: Xcel Energy Transmission Planning in conjunction with Siemens Power Technologies International (January 22, 2016)

Black Start Plan Analysis performed by: Xcel Energy Realtime Transmission Planning

January 29, 2016

This is designed to help prevent key information about our system and the grid from being accessible.

Contains Non-Public Information:
The Company developed this grid primer and summary report in an effort to provide a public report of its technical analyses and conclusions as they relate to the potential retirement of its Sherburne County Generating Plant (Sherco) Units 1 and 2. The reports and analyses themselves contain critical electrical infrastructure information (CEII) and other highly-sensitive information about the Xcel Energy and other regional transmission owner systems, so are entirely not public. We maintain that the partially-redacted study reports are "security information" as defined by Minn. Stat. § 13.37, subd. 1(a). We have also redacted limited portions of this summary report. We take seriously our responsibility to maintain the security of the information and systems involved in the delivery of safe, reliable energy to our customers. A key tenet of our security program is limiting the extent to which sensitive information is accessed or shared. This is designed to help prevent key information about our system and the grid from being accessible. While we are not providing full Attachment Y2 and Siemens study reports available with this filing, we are open to discussing the specifics of the reports with parties to this docket who have signed a supplementary Non-Disclosure Agreement, provided that the information would remain adequately protected. Alternatively, the Company will make the full study reports available for inspection by Xcel Energy regulators who have fulfilled MISO's CEII requirements and will also consider making them available to certain other parties to the proceeding who have fulfilled MISO's CEII requirements and Xcel Energy's supplementary non-disclosure requirements. We provide a full justification of our non-public treatment of this information in the cover letter accompanying our January 29, 2016 Resource Plan Supplement.

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I. INTRODUCTION

Xcel Energy initiated three technical studies to examine the transmission reliability impacts of its Sherburne County Generating Plant (Sherco) Units 1 and/or 2 if they were to cease operations: (1) a *Midcontinent Independent System Operator (MISO) Attachment Y2 Study*; (2) an *Xcel Energy Transmission Reliability Study*, performed in conjunction with Siemens Power Technologies International (Siemens); and (3) a *Black Start Plan Analysis.* The Company's conclusions from these studies is that: (1) ceasing operation of Sherco Units 1 and 2 would create system conditions that require mitigation; and (2) siting dispatchable, thermal generation at the Sherco site is the most cost-effective solution and provides the greatest level of certainty in terms of cost and reliability to meet the Company's energy and capacity requirements, maintain reliability for its customers, and support the Company's vision of a clean energy future.

The electric "grid" is a large complex machine consisting of generation and transmission facilities that operates across a very large geographic area. The NSP System is part of the Eastern Interconnection, which connects the electrical grids from the Rocky Mountains to the East Coast, and from Canada to the Gulf of Mexico. This interconnected network of generating resources and transmission infrastructure works together to seamlessly respond and adjust to dynamic and sometimes adverse circumstances to provide an adequate and reliable supply of electricity to customers. Each resource and system component plays a unique role based on its size, type and location on the system – and because the grid is so integrated, generation changes made to one utility's system can impact other portions of the system.

The Sherco Plant is the largest power station in the Midwest, consisting of three units that have a total generating capacity of 2,250 MW. Units 1 and 2 that are a focus in the 2016-2030 Resource Plan are wholly-owned baseload facilities with generating capacity of approximately 700 MW each for a total of approximately 1,400 MW. Both the Company's Sherco Plant and Monticello Nuclear Plant are located in Sherburne County Minnesota, making the location of these large, baseload generating facilities a very important consideration in maintaining system stability and reliability. Together, these plants total nearly 3,000 MW of generating capacity, or approximately 30 percent of the Company's total existing generating capacity.[1]

With the concentration of so much generation in one geographic area, the electrical

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[1] Generating capacities are expressed as MISO Unforced Capacity (UCAP) values. Values for the Sherco Plant include both the Xcel Energy and the SMMPA ownership shares of Sherco Unit 3.

performance of the regional transmission system – and the entire mix of resources on the NSP System – is fundamentally designed around these Units. 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. Large generating units like Sherco Units 1 and 2 afford the capability for the system 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 compromised.

Similarly, the frequency regulation of the transmission system is governed by the connected generating units. If system frequency deviates beyond allowable levels, protective devices will disconnect generation and/or customer load from the rest of the system. These disconnections can further exacerbate any imbalance between load and generation, which may cause further disconnections and shedding of load. Sherco Units 1 and 2 provide the spinning mass that assists in maintaining the 60 hertz (Hz) 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. Therefore, potentially ceasing coal operations of one or both Sherco Units 1 and 2 as we have proposed in our Current Preferred Plan must consider more than replacement of the capacity and energy they provide to our customers.

When performing technical studies, we simulate a number of varied conditions that can consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently. The studies generally analyze the way power flows over the grid, and search for places where the system might overload or fail, assuming specific circumstances. We measure these results against North American Electric Reliability Corporation (NERC) requirements.[2] NERC is designated by the Federal Energy Regulatory Commission as the Electric Reliability Organization, which is the independent entity that develops and enforces mandatory standards for the reliable operation and planning of the bulk-power system throughout North America, as called for in the Energy Policy Act of 2005.

NERC defines a reliable bulk-power system as one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity, and divides reliability into two categories:[3]

[2] We provide an abbreviated list of NERC Event Categories in Table 13 in Section IV.C.3 of this Summary Report.
[3] http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf

- *Adequacy*. Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
- *Security*. For decades, NERC and the bulk power industry defined system security as the ability of the bulk-power system to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by manmade physical or cyber attacks. The bulk-power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.

NERC additionally authorizes regional entities, which in the Upper Midwest is the Midwest Reliability Organization. Also a regional entity MISO is an independent, not-for-profit company authorized by FERC to provide open-access transmission service, operate the transmission grid, administrate a wholesale energy market, and perform regional transmission planning in 15 states throughout the Midwest and Southern United States, and Manitoba, Canada.[4] MISO is also the Regional Transmission Organization that ensures electric reliability and optimizes supply and demand bids for wholesale electric power in their region. The Xcel Energy operating companies that comprise the NSP System (Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin) are signatories to the MISO Transmission Owners Agreement and are therefore members of MISO and thus subject to MISO Tariffs and requirements.

The three studies we initiated examined differing aspects of potentially retiring Sherco Units 1 and 2, as follows:

MISO Attachment Y2 Study. 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. Therefore, the focus of this Study was on the impacts to the grid if one or both of Sherco Units 1 and 2 ceased operation. We initiated a Study

[4] Independent System Operators grew out of FERC Orders Nos. 888/889 where FERC suggested the concept of an Independent System Operator as one way for existing tight power pools to satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, in Order No. 2000, FERC encouraged the voluntary formation of Regional Transmission Organizations to administer the transmission grid on a regional basis throughout North America (including Canada).

under Attachment Y2 of the MISO Tariff, which is a non-binding, informational study. The Y2 Study is intended to determine whether it is likely that the system resource would qualify as a System Support Resource (SSR) in conjunction with an Attachment Y Study, which is a final, binding study that must be conducted under the MISO tariff once a retirement date-certain is determined.[5]

The MISO Y2 Study concluded that retirement of Sherco Units 1 and 2 would result in violations of applicable planning criteria that would require transmission upgrades and the need for the Units to be designated as SSRs. Assuming a future Attachment Y study would have similar results, MISO would require that the identified violations be mitigated to its satisfaction prior to retirement of Sherco Unit 1 and Unit 2, if replacement generation is not located at Sherco.[6]

The Study found that retirement of both units would result in a major reactive power deficiency in the Monticello area that would cause a violation of Monticello's Nuclear Plant Interface Requirements (NPIR) voltage requirements that would be a violation of Monticello's Nuclear Plant Operating Agreement.[7] The plant would not be allowed to operate if the voltage falls below its NPIR minimum threshold. The Study also identified a number of other reliability issues, including thermal overloads of 115 kV and 345 kV transmission lines and some smaller scale voltage deficiencies.

Xcel Energy Transmission Reliability Study. We retained Siemens to study the effects of potential retirement of one or both Sherco Units on the transmission system, and technical implications and upgrade costs associated replacement of one or both Units at alternate locations on the NSP System. Our Study used the same system models as MISO used for its Y2 Study, but differed in that the Y2 Study did not examine replacement of all or a portion of Unit 1 and 2 generation. Our Reliability Study also set out to examine the potential impacts from the cumulative effect of additional larger generation unit retirements on the NSP System by also studying the shutdowns of the Monticello Nuclear Plant due to its proximate location to Sherco, and one Prairie Island Unit in combination with Sherco Units 1 and 2. We decided however to pause this work, in light of the increased interest in the future of our nuclear

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[5] Per Section 38.2.7 of the MISO Open Access Transmission, Energy, and Operating Reserve Markets tariff.
[6] MISO has proposed tariff changes to the Attachment Y notification process that could make such Notice unnecessary. If a generating unit is being replaced with an equal- or larger-sized (MW) unit, an Attachment Y notice would not be required; only an Interconnection request for the new unit utilizing the existing interconnection rights would be required. An SSR study under Attachment Y of MISO's tariff would only be required if the new/replacement generating unit is smaller (MW) than the unit being retired.
[7] The Monticello Nuclear Plant, along with all nuclear plants in the United States have NPIR voltage requirements that are required to support FERC/NERC Regulation NUC-001. NUC-001 requires coordination between nuclear plant operators and transmission entities for the purpose of ensuring safe nuclear plant operation and shutdown.

units. As we discuss in Section VII of our January 29, 2016 Resource Plan Supplement, we intend to initiate a more broad and in-depth study of the effects of a potential shutdown of our nuclear units on our transmission system in 2016.

Our Reliability Study involved a full thermal analysis, full voltage analysis, and transient stability analysis, and confirmed that the existing transmission system with significant generation injection at Sherco works well, and plays a significant role in providing reliable service for NSP System customers and other customers in our portion of the MISO region. It also concluded that there are transmission upgrade costs and other trade-offs associated with replacing Sherco Units 1 and 2 at an alternative location, such as increased energy losses the farther the replacement generation is located from the Twin Cities load center.

Black Start Plan Analysis. A Black Start Plan specifies the process of restoring the grid to full operation without relying on the external transmission network following a full- or partial-black out. Black Start Plans are required by NERC, developed in concert with neighboring utilities, and are subject to review and approval by MISO. Sherco Units 1 and 2 are currently the primary Target Units, or first generating units to be repowered as part of our Black Start Plan. This analysis examined the viability and costs associated with changing the current system restoration path from Sherco Units 1 and 2.

Our Black Start Plan analysis concluded that without the current Sherco Unit 1 and 2 restoration path from our Initial Unit(s), we would need to rely on different restoration paths to multiple Target Units.[8] We will need additional facilities on the alternative restoration paths and altering our path causes restoration of our system and customer load to take longer. The expediency of the restoration path is particularly important in winter/cold weather, because a delay of as little as one hour could mean that we may have to begin draining our boiler systems or taking additional measures at our steam generating plants before they freeze and are damaged. If this is necessary, restarting those plants could take several days, which could impact restoration of our customers.

It is important to note that the assumptions used in these studies are based on expected conditions at the time they were initiated in early 2015. The system is dynamic and expected conditions can change when new generation comes online, new transmission lines are constructed, or existing lines are reconfigured.

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[8] The Initial Unit is the first generating unit that sets restoration in motion. Target Units are the generating Units on the restoration path that was started by the Initial Unit.

We believe a combination of EPA's Clean Power Plan along with aging generation assets will significantly change the generation mix in the United States over the next 15 years. Not only have we started to perform studies to understand the potential impact of significant generation changes, the industry is also beginning to examine the potential impacts of a changing generation mix. Entities such as NERC and MISO are beginning to study the potential cumulative impacts of significant generation changes across the country.[9]

We have many years ahead of us to try to simulate and understand the cumulative effect of a different mix of generating units. We know what we have today works well, and to the extent replacement generation is located in similar electrical locations, we are confident the grid will continue to perform well.

II. CURRENT SYSTEM/GRID

A. Overview

The "grid" is a large complex machine consisting of existing generation and transmission facilities that operates across a very large area. The NSP System is part of the Eastern Interconnection, which connects the electrical grids from the Rocky Mountains to the East Coast and from Canada to the Gulf of Mexico.

The Twin Cities metro area is surrounded by a double circuit 345 kV *bulk* transmission system that extends from Benton County in the north, east to Chisago County, south to Dakota County, west to Scott County, and back north to Becker, Minnesota. This 600 mile ring of 345 kV lines encompassing nearly 1,300 square miles forms the backbone of the bulk transmission system feeding the Twin Cities load center. This 345 kV ring is connected through several bulk 345 kV lines tying to our neighboring utilities, and a 500 kV bulk transmission line to Manitoba Hydro in the north. These tie-lines connect the Twin Cities load center to the MISO generation market and the Eastern Interconnection – providing important "back-up," should there be an unexpected event that requires the Company to rely on the grid to maintain reliability for our customers.

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[9] *See* NERC Potential Reliability Impacts of EPA's Proposed Clean Power Plan (Phase I) at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential%20Reliability%20Impacts%20of%20EPA%E2%80%99s%20Proposed%20Clean%20Power%20Plan%20-%20Phase%20I.pdf and MISO Analysis of EPA's Final Clean Power Plan Study Scope (November 2015) at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2015/20151111/20151111%20PAC%20Item%2003e%20Clean%20Power%20Plan%20Final%20Rule%20Analysis%20Scope.pdf

The 345 kV ring that surrounds the Twin Cities feeds the underlying Twin Cities 115 kV transmission grid, which connects to our low voltage distribution system that delivers the power directly to businesses, houses and other loads. The transmission system and the lower voltage distribution system in the Twin Cities area has developed over the past 100 years to serve the growing area, and is constantly being analyzed and updated to ensure optimal and reliable power delivery.

Our bulk transmission system is anchored at the corners by several large coal and nuclear generators that act as the baseload generation for the NSP System. They include Sherco (coal) and Monticello (nuclear) in the northwest and A. S. King (coal) and Prairie Island (nuclear) in the east and southeast. Together these plants provide over 4,020 MW of capacity and over 29,000 GWh of energy to our customers, which represents 46 percent of the NSP System generating capacity and 65 percent of the system energy. This generation is supplemented by several natural gas generating plants located on the 115 kV system in the Twin Cities. These generating units include Riverside, Highbridge, Black Dog, and Blue Lake. The 500 kV line that ties into Chisago County substation in the northeast connects the hydro power produced by Manitoba Hydro to the Twin Cities load center. A significant proportion of our wind power is located in southwest Minnesota and is tied into the Twin Cities through a number of lines developed over a period of years to connect the wind-rich areas in southwest Minnesota and South Dakota to the Twin Cities load center. A robust transmission system such as this facilitates the provision of reliable, low cost power to our customers from a diverse mix of generation resources, and mitigates risk from catastrophic events.

The existing grid is a valuable asset and an enabler that has and will continue to support the evolution and growth of our system. The grid has facilitated integration of substantial wind generation onto the NSP System by absorbing the inherent fluctuations of this variable generation type over a large area. Transmission enables the transfer of wind and solar and other types of generation from where it is most effectively located to customer load located elsewhere where it can be utilized to the fullest extent.

Over time, we expect that there will be more and more development of microgrids and other new technologies such as batteries. Rather than competing with the existing grid, these new technologies will be complementary, in that each system can support and help the other. For example, to the extent microgrids have challenges, the grid can help provide reliability to those areas – and as microgrids develop over time, there will be more and more integration of the capabilities they can provide into grid operations.

B. Key Elements Ensure Reliable Service

Electrical system reliability can be defined as the ability of the electrical grid, which includes transmission, generation, distribution and related components, to serve customer load under any system condition. Maintaining a reliable electricity supply for customers requires that generation, load and electrical losses balance – and maintain a 60 Hz frequency. If the frequency varies only one or two tenths of a hertz from 60 Hz, it can cause damage to equipment, and automated protection schemes will disconnect pieces of the grid to avoid damaging equipment.

A strong transmission system improves the reliability of the electric power system, and facilitates a diverse and low cost resource portfolio for customers – allowing lower cost resources with diverse fuel types, and resource types not available in the immediate area to be efficiently transported to serve their needs. For example, wind resources need to be constructed where the wind is strongest and most consistent; large-scale solar resources where there is sufficient land and the most consistent sunshine – both of which are generally away from large population centers. A robust transmission system brings together varied generating units – some built to run continually, others only to run at peak times when they are most needed, and renewable resources on an intermittent basis – together into an integrated grid.

The system must also be able to facilitate both "active" and "reactive" power, which are typically produced by non-renewable generating unit types. Active power, measured in watts, is the form of electricity that powers equipment. Reactive power, measured in volt-amperes reactive (VARs), is the energy supplied to create or be stored in electric or magnetic fields in and around electrical equipment. Reactive power is particularly important for equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps and air conditioning). Reactive power can be transmitted only over relatively short distances, and thus must be supplied as needed from nearby generators. If reactive power cannot be supplied promptly and in sufficient quantity, voltages deteriorate and, in extreme cases, can result in a voltage collapse.

The grid must also be able to adjust to changing customer loads, the availability of diverse resources, and have sufficient redundancy built-in, making it capable to withstand the failure of its most critical lines, generators, or other components. As customer load changes over the course of a day, generation must change to accommodate the load at any given time. With the high penetration of renewables on the NSP System, we must ensure that we have adequate dispatchable generation to both accommodate the load and whatever generation mix we have at each point in time. We must also maintain a spinning reserve – generation that is available at a moment's notice – to account for the largest contingency in the area.[10] Having large coal generating units has helped, because they have the ability to be "turned up" and "turned down" based on the level of renewable generation being delivered to the system at any given time.

C. Role of Sherco Units 1 and 2

Sherco Units 1 and 2, located in Becker, Minnesota play an important role in the reliable electrical service we provide to our customers. Together, they produce approximately 1,400 MW of capacity and associated energy, and are tied to the transmission grid through five 345 kV and two 115 kV lines.

As we have discussed, 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 the NSP System, has been designed 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 operational services.

Potentially ceasing coal operations of one or both of these Units must consider more than replacement of their energy output. The Units' technical characteristics include:

- *Power Deliverability*. The existing transmission system has been developed to be able to receive the approximately 1,400 MW of power injected from Sherco Units 1 and 2 and to deliver it to various area substations to meet the electrical power demands of customers. This power deliverability capability is often referred to as "transfer capability" or "thermal limits" of the system. Transmission systems are made capable of receiving and moving power from specific generators at specific locations; changing generator characteristics or locations requires corresponding changes to grid capabilities.
- *Dynamic Stability*. The transmission grid is a vast interconnected machine with many parts. There are a mix of large and small gears in this machine, all spinning at the same rate (i.e. synchronous), simultaneously producing and

[10] Spinning Reserve is unloaded operating capacity available on units connected to and synchronized with the interconnected electric system and ready to take load immediately in response to a frequency deviation.

delivering electricity to customers. Generating units are the spinning gears in this machine. Large generators like Sherco Units 1 and 2 have large spinning shafts that provide a strong backbone for the machine's operation. With enough of these big "gears" spinning, the machine can stay electrically stable and continue operating without interruption when small gears drop in and out of operation (like when the wind stops blowing or sun stops shining), or when another big gear drops out, or a "contingency," happens to some part of the machine. These large gears are also more likely to stay connected to the grid during a contingency than the small gears because large rotating masses have more inertia and are therefore not as easily jarred, or disrupted by a disturbance. Having the large gears in place also enables more small gears to be connected to the machine because they don't have as much impact with the large gears in place. The large generating units thus provide "dynamic stability" to the grid.

- *Fault Current.* Large synchronous generating units provide "fault current," which is necessary for the system protection equipment to function properly. If the system has too little fault current, it is difficult for system protection systems to differentiate customer load from an electric fault, which could cause the protection system to not function properly.[11] The protection system is the overarching electrical monitoring scheme that assesses the real time condition of the transmission grid and acts to prevent damage to system components and prevent cascading failures. The large generating units operating today are important sources of fault current, and the protection system and existing deployed assets rely on sufficient fault current for the protection system and other electrical facilities to work as designed. Many of the electric devices that are deployed on the grid and in service today, such as wind generators and other assets, are engineered and designed to function properly with the amount of fault current that has been historically available on the grid. Therefore, changing the amount of fault current on the grid could not only impact protection systems, but could also impact other electric assets.

- *Black Start Capability.* In the event of a major regional grid outage, Sherco Units 1 and 2 are an integral resource to restoring power to the electrical grid, or "restarting the machine." Only dispatchable generating units of a certain size that are capable of creating and absorbing reactive power are eligible to perform black start functions. Our current plan requires Initial Unit(s) of approximately 110 MW and up to 300 MW to get the restoration started. Sherco Units 1 and 2, because of their ability to operate at lower outputs, along with their reactive capabilities, are considered eligible Target Units, which are

[11] For example, the protective equipment could misinterpret the load as a fault, and de-energize an unfaulted circuit.

the next units used in the restoration. Sherco Unit 3 is not a viable Target Unit, because it is too large for the Initial Unit(s) to start, so is started later in the process. Additionally, nuclear units are not viable Target Units, because they cannot vary their output and can only come online after the system is fully stable. Renewable generation, such as solar and wind are not currently considered eligible Target Units due to their inherent intermittent nature, and their inability to provide or absorb reactive power.

- *Voltage Support.* The real time conditions on the transmission system are constantly changing and require ongoing adjustments to maintain voltages at required levels. The Sherco 1 and 2 Units, as large synchronous power sources, provide significant system voltage support along with necessary "reactive power." Reactive power is required to start and run motors, like in air conditioners and industrial equipment (called "inductive loads"). Large population centers generally require large generating units located reasonably nearby to support system voltage effectively. As in the dynamic stability discussion, without enough large units in place, the machine isn't as capable and robust when it runs.

- *System Regulation.* System regulation essentially means the ability of the system to respond instantly to changes in usage, i.e. keeping the generators and loads exactly matched at all times. Sherco Units 1 and 2 have the electrical characteristics to provide this fast response balancing in real time. The system frequency, required to be maintained at 60 Hz in the US grid, is an active measure of this balance. When there are sudden large changes to the generation/load balance, as when a generating unit drops offline or a large industrial load (like a smelter) comes online, the frequency drops if there is insufficient regulation capability on the system. This is another aspect of the dynamic stability of the system.

III. TECHNICAL STUDIES OVERVIEW

As we have discussed, the grid is a complex machine that is integrated over very large portions of the country. The bulk and load serving NSP System has been developed over the past 100 years to serve the growing area, and is constantly being analyzed to ensure optimal and reliable power delivery. We have a great deal of experience both in studying the existing grid and operating it in many varying conditions (during high load, low load, high transfers, low transfers, storm conditions, outages or equipment).

When performing technical studies, we simulate a number of varied conditions that can consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently. The studies generally analyze the way power flows over the grid and search for places where the system might overload or fail, assuming specific circumstances. While studies are essential and provide important insights, our decades of operating and studying the existing system provides valuable insights and perspective in siting considerations for replacing Sherco Unit 1 and 2 generation.

We have stated previously that our initial assessment was that completely replacing the baseload energy from Sherco Units 1 and 2 with renewable energy facilities was likely infeasible from a reliability perspective. Our Studies support the conclusion that the addition of dispatchable, thermal generation at the Sherco site will ensure ongoing reliability of the NSP System for our customers in the most cost-effective manner. Having sufficient dispatchable generation on the system also supports the addition of the significant levels of renewable generation we propose with this Resource Plan.

We are confident that generation injections in locations where those electrical injections occur today will result in a high level of reliability and good performance from our transmission system. With that said, we have proposed to replace a portion of Sherco Units 1 and 2 energy and capacity with a natural gas combined cycle (CC) at the Sherco site. We believe this proposal is superior to alternatives, will provide necessary voltage support to the Monticello Nuclear Plant and surrounding area, and is cost-effective for our customers.

We note that the MISO Y2 Study and our Reliability Study identify transmission upgrades necessary to resolve the respective issues the studies identified. In addition to these transmission upgrades, there are additional (interconnection) transmission costs involved to connect generation to the grid. Therefore, to get a full picture of the costs, interconnection costs must to be added to the transmission upgrade costs.

A. Studies Performed

As outlined previously, we initiated three studies to understand the technical implications and to identify any mitigating measures that must be undertaken, as follows:

- *MISO Y2 Study*,
- *Xcel Energy Transmission Reliability Study,* and
- *Black Start Study*.

Our Studies used the best information available at the time they were initiated to develop the models used to conduct the analyses; MISO performed its Y2 Study in accordance with their Business Practice Manuals.[12] However, all studies are essentially an attempt to predict what is going to happen in the future – and the conditions and underlying assumptions of a dynamic system are subject to change. Therefore, there are inherent limitations in any study effort.

B. MISO Attachment Y2 Study

1. Overview

As we discussed in our October 2, 2015 Reply Comments, we initiated a MISO Attachment Y2 Study to examine the reliability impacts from the potential retirement of one or both Sherco Units 1 and 2. The Y2 Study is intended to determine whether it is likely that the system resource would qualify as a System Support Resource (SSR) in conjunction with an Attachment Y Study, which is a final, binding study that must be conducted under the MISO tariff once a generation owner determines a retirement date-certain. The study impacts are measured based on the criteria set forth in the MISO Business Practices Manuals, which apply NERC requirements, and include monitoring and identifying the steady state branch/voltage violations and the transient stability violations on transmission facilities due to the unavailability of the generating resources.

The Company's request was for MISO to analyze retirement of Sherco Units 1 and 2 under two retirement scenarios: (1) retire Sherco Unit 1 and Sherco Unit 2 on May 31, 2021; and (2) retire Sherco Unit 2 on May 31, 2021 and Sherco Unit 1 on May 31, 2024. Because Sherco Units 1, 2, and 3 (in addition to Monticello) are the largest reactive power resources in the Twin Cities area, MISO specifically assessed the voltage implications under certain power transfer scenarios if all of these plants were out of service. Finally, due to the electrical proximity between the Monticello Nuclear Plant and Sherco, MISO assessed the voltages at Monticello's 115 kV and 345 kV busses to ensure they remained within the very specific and narrow range specified in Monticello's NPIR.

2. Study Results

The MISO Y2 Study concluded that ceasing operations at Sherco Units 1 and 2 would create system conditions that violate NERC requirements that would require transmission upgrades and the need for the Units to be designated as SSRs.

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[12] *See* MISO Business Practice Manual BPM-020 at: https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

Assuming a future Attachment Y study would have similar results, MISO would require that the Company mitigate identified violations to its satisfaction prior to retirement of Sherco Unit 1 and Unit 2, if replacement generation is not located at Sherco.

At a high level, the MISO Y2 Study identified several voltage violations due to a substantial reactive power deficiency in the Monticello area that is a major concern and needs to be addressed to maintain voltages at Monticello Nuclear Plant within its permissible range. The Monticello Nuclear Plant cannot operate if its voltage is outside the permissible range. If only one Sherco Unit retires and the other Unit remains in service, the analysis identified a smaller reactive power deficiency that would need to be addressed, and some other relatively minor reliability issues that can be addressed by minor equipment installations such as capacitors.

The MISO Y2 Study also identified thermal violations (transmission lines above their rated capability) created when replacement generation was dispatched from others areas of the MISO system. For example, a rebuild of a 345 kV line to 3,000 Amperes was an identified action that would be needed to alleviate some identified thermal violations. With regard to system stability, the transient stability assessment showed acceptable behavior without Sherco Units 1 and 2.

The specific Study conclusions that require mitigation are as follows:

- Several voltage violations due to a reactive power deficiency in the area that violate Monticello's NPIR voltage requirements, would be a violation of Monticello's Nuclear Plant Operating Agreement, and would require the plant to cease operation until the voltage is within the NPIR range,
- A 25 MVAR capacitor bank would need to be installed in 2017 at WMU-Priam 115 kV bus to alleviate local voltage issues. (*Note*: this is existing MISO MTEP Project 4380, so will not result in incremental cost to the Company),
- A capacitor bank(s) would be needed at the 115 kV bus of a generating station to maintain the voltage above their minimum voltage requirements,
- The rebuild of a 345 kV line to 3,000 Amperes to alleviate a portion of the identified thermal violations,
- A 115 kV line may also need to be rebuilt to alleviate other thermal issues per the SSR criteria, and
- Voltages at Monticello's 115 kV and 345 kV buses are lower than the plant's voltage requirements.

We note that the CC generating unit we have proposed for the Sherco site would fully resolve these issues.

3. *Mitigation of Identified Issues*

The CC generating unit we have proposed for the Sherco site is our preferred option for mitigating the violations identified in the MISO Y2 Study. However, in the alternative, MISO identified potential ways to mitigate the identified impacts, which we estimate would cost approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** in capital, plus significant ongoing operating and maintenance costs to mitigate. We outline these measures in Table 1 below, and also discuss the Synchronous Condenser, which at approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** in capital, is the most significant of the mitigating measures.

Table 1: MISO Potential Mitigation Measures and Xcel Energy Estimated Cost ($Millions – 2015)

MISO Identified Potential Mitigation Measure	Xcel Energy Potential Mitigation Measure and Estimated Cost
Reductions and runbacks to existing generators	None
Transfer of certain feeder loads	None
Tripping of certain transmission lines	None
Install reactive capacity on system to maintain voltages at Monticello Nuclear Plant within permissible range as per the Monticello NPIR	Convert Sherco Unit 1 or Unit 2 to a Synchronous Condenser – **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
Install Proposed Project including a 25 MVAR capacitor bank to be installed at substation in 2017 *(already planned)*	No incremental cost to Company
An MTEP project addresses the 115kV system voltage issues resulting from events *(already planned)*	No incremental cost to Company
Increase capacity of a 115 kV line	Rebuild the line – **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
Install capacitor banks at generator station 115 kV bus.	Install capacitor bank(s) & upgrade substation – **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
Rebuild of 345 kV line to 3000 Amperes is needed to alleviate some identified thermal violations	Rebuild the line – **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**

Synchronous Condenser – As we have described, large generators play a very important role on the system, one of which is providing necessary reactive power to the grid. If reactive power cannot be supplied promptly and in sufficient quantity, maintaining voltage is challenging, which is the case with Monticello's NPIR. Therefore, if no replacement generation is installed at Sherco, we would need to install other equipment that can both generate and absorb reactive power as needed to adjust the grid's voltage. Sherco would be a good location for this other equipment because reactive power can only be practically transmitted over relatively short distances.

There are currently three available options to address this issue: (1) a Synchronous Condenser (SC); (2) a Static Var Compensator (SVC); or (3) a Static synchronous compensator (Statcom). Considering the three alternatives, we believe the best option for the NSP System is to convert Sherco Unit 1 or Unit 2 to an SC. Installation and operation of an SC is identical to large electric motors and generators. It is controlled by a voltage regulator to either generate or absorb reactive power as needed to adjust the grid's voltage, or to improve power factor. Its principal advantage is the ease with which the amount of correction can be adjusted. However, importantly, SCs provide not only the required continuous range of voltage support, but are also a rotating mass that helps hold the grid electrically together following a disturbance such as a major fault. As we have described, there are significant system stability benefits associated with the inertia provided by large rotating masses.

As a point of reference, an SVC is a set of electrical devices for providing fast-acting reactive power. Unlike an SC, which is a rotating electrical machine, an SVC has no significant moving parts (other than internal switchgear). The main advantage of SVCs over simple mechanically-switched compensation schemes is their near-instantaneous response to changes in the system voltage. Similarly, a Statcom is a regulating device that can either provide or absorb reactive power. It is inherently modular and has better characteristics than an SVC. In contrast to an SVC, its maximum reactive output current will not be affected by the voltage magnitude, whereas the SVC's reactive output is proportional to the square of the voltage magnitude, which makes the provided reactive power decrease rapidly when voltage decreases, thus reducing its stability. In addition, the speed of response of a Statcom is faster than that of an SVC and its harmonic emission is lower. Statcoms typically exhibit higher losses and are generally more expensive than SVCs, so are not in widespread use.

Both SVCs and Statcoms are generally less expensive than SCs, however, neither offers the significant stability benefits that come from having large, rotating mass around our system – and both introduce harmonics into the grid. In general, harmonics cause power quality problems, and result in increased heating in equipment and conductors, misfiring in variable speed drives, and torque pulsations in motors, which would potentially affect both our equipment and that of our customers. Additionally, there are other electronic devices on the system, such as the D.C. terminal in the western Twin Cities that has electronic equipment that can be negatively impacted by harmonics. For these reasons, we have determined the SC is the best solution for the NSP System.

4. *Summary*

We note that these results are based on assumptions and the MISO system as it was known in March 2015. We believe it is reasonable to conclude that the MISO Y2 Study results could be viewed as optimistic, since other generators assumed to be running at the time of this study will likely be different than when MISO performs their official Attachment Y analysis, which is currently required in the 26-week period preceding an actual planned Unit retirement.[13]

We are confident, however, that regardless of the status of other generators in the MISO system, the natural gas CC we have proposed to construct at the Sherco site in 2026 is the best solution to mitigate any technical issues associated with retiring Sherco Units 1 and 2.[14] As we have discussed, a large generator plays a very important role on the system, in terms of providing necessary reactive power and maintaining its voltage, frequency and overall stability. For the reasons we have discussed, by placing a large generator at the same injection point on the transmission system, we have absolute confidence that the system will function as well as it does today.

Placing a large generating unit at Sherco will handle the inevitable disturbances the grid successfully deals with every day, which range from ever-changing electric use (i.e., as people/businesses turn on and off electrical equipment), periodic changes to power transfers as electric markets dispatch generation every five minutes, to periodic outages (planned or unplanned), to adverse weather, and other impacts caused by humans, animals, trees, etc.

We discuss the MISO Y2 Study approach, assumptions and inputs in Section IV. below.

[13] As noted previously, MISO is contemplating changes to its Attachment Y requirements.

[14] The MISO Y2 Study identified minor issues related to retirement of the first Unit, which we believe can be resolved without the need for significant upgrades.

C. Xcel Energy Transmission Reliability Study

In early 2015, we engaged Siemens Power Technologies International to gain technical insights as to the local and regional transmission impacts of ceasing coal operations at Sherco Units 1 and 2. The study consisted of two components: (1) analyze alternative locations for replacement generation for Sherco Units 1 and 2, and (2) identify deficiencies in ensuring ongoing reliable energy delivery to our Upper Midwest customers by performing a full technical analysis of the impacts of retiring significant baseload generation from our system and determine potential long-term solutions.

We conducted our Reliability Study in phases: (1) Retirement of one of the Sherco Units 1 and 2; and (2) Retirement of both Sherco Units 1 and 2. The Study included the following analysis for both local and regional transmission facility impacts and disturbances with one or both Sherco Units 1 and 2 out of service:

- *Full thermal analysis*. Thermal analysis evaluates the steady-state flows (greater than 30 seconds) on the transmission system following a disturbance and identifies transmission facilities that are outside their allowable thermal ratings. The thermal analysis also calculates system losses.
- *Full voltage analysis*. Voltage analysis evaluates the steady-state voltages (greater than 30 seconds) on the transmission system following a disturbance, and identifies transmission facilities that are outside their allowable voltage limits.
- *Transient stability*. A transient stability analysis evaluates whether the power system electrically "stays together" and the impact on the transmission system following a disturbance, and identifies transmission facilities that are outside their allowable stability limits. Specifically, we looked at the ability of the grid to maintain electrical connection following disturbances.

Our Reliability Study used the same MISO MTEP14 models as the MISO Y2 Study, adjusted to reflect the 2020 timeframe, and applied the same planning criteria. However, because the MISO Y2 and the Reliability Studies have different base input assumptions, the two studies investigate different perspectives on the issue of retiring one or two Units at Sherco. Additionally, our Reliability Study differs from the MISO Y2 Study in that the MISO Y2 Study analyzed the impacts of turning off one or both Sherco Units 1 and 2 assuming no replacement generation. Its purpose was to determine how the system would behave in the absence of these generators. Our Reliability Study also analyzed impacts on the transmission system and estimated transmission upgrade costs related to ceasing coal operations at Sherco Unit 1 and 2 *and replacing the generation* at alternate locations as follows: (1) Metro – a location near the Twin Cities; (2) Southwest – a location in southwest Minnesota; and (3) Northwest – a location in eastern North Dakota.

Our Reliability Study's conclusions were consistent with the MISO Y2 Study conclusions, in that they also identified NERC violations that would need to be mitigated if Sherco Unit 1 and 2 are retired. Specifically, we concluded:

1) Siting replacement generating units outside of Sherco is technically feasible but would require transmission system upgrades.
2) The required transmission system upgrades for replacement generation outside of Sherco is dependent on other generation that is included in the study.
3) The further the replacement generation was located from the Twin Cities load center, the greater the transmission losses.

Importantly, our Reliability Study concluded that replacement with a large generating unit that provides similar benefits to the NSP System as Sherco Units 1 and 2 will cost-effectively ensure voltage, frequency, and reliable service for our customers. Additionally, the Study in combination with other identified costs supports that replacement at the current Sherco site is superior and the most economical of the alternatives studied. Finally, our Reliability Study supports the conclusion that locating thermal replacement generation at Sherco provides the most cost certainty with regard to required transmission upgrades, since the Sherco site can utilize existing transmission facilities and interconnection rights – and the grid is constructed such to expect a large generation injection at that location.

It is important to note that our Reliability Study was initiated in early 2015. Since that time, significant amounts of generation have entered the MISO interconnection queue, so the estimated transmission mitigation costs we outline are very likely optimistic, because the generating resources that are in the queue will come online and will "use up" transmission capacity that our Study assumed would be available in the future.

1. Siting Replacement Generating Units Outside of Sherco is Technically Feasible but Would Require Transmission System Upgrades

In this section, we outline the transmission mitigation costs of locating replacement generation at studied locations other than Sherco. The Reliability Study showed that transmission mitigation costs (not including interconnection costs) increase the further away you move the generation from the Twin Cities load center.

Table 2: Estimated Costs – One 750 MW Combined Cycle Unit
($millions - 2015)

Alternate Location	Transmission Mitigation	Generation Interconnection	Total
[TRADE SECRET BEGINS…			
Metro			
Northwest			
Southwest			
			…TRADE SECRET ENDS]

Table 3: Estimated Costs – Two 750 MW Combined Cycle Units
($ millions - 2015)

Alternate Location	Transmission Mitigation	Generation Interconnection	Total
[TRADE SECRET BEGINS…			
Southwest Metro			
Northwest Metro			
Northwest Southwest			
			…TRADE SECRET ENDS]

The indicated Generator Interconnection costs in Tables 2 and 3 above are planning level estimates for the electrical facilities necessary to connect the generating plant to the Point of Interconnection (POI) and include a 345 kV substation that will accommodate a CC unit with two simple cycle turbines and one steam turbine and the 345 kV line which will connect the generator to the MISO POI. The costs vary between generator locations due to the assumed lengths of the transmission line. The generation interconnection costs also include the expected cost to expand the POI substation to accommodate the line from the generator, costs for metering and relaying and other interconnection facilities required by the MISO generation interconnection process. The basis for the costs is historical facility studies performed for other Xcel Energy generator interconnections.

2. The Required Transmission System Upgrades for Replacement Generation Outside of Sherco is Dependent on Other Generation Included in the Study

Greater amounts of generation sited at locations other than Sherco result in the need for more significant transmission upgrades (and costs) to support delivery and interconnection of the generation, as shown in Table 3 above.

3. The Further the Replacement Generation was Located From the Twin Cities Load Center, the Greater the Transmission Losses

The Reliability Study results indicate that the further from the Twin Cities load center that the replacement generation is located, the higher the losses. Tables 4 and 5 below show transmission system losses for peak load and shoulder load conditions for the alternate replacement generation location.

Table 4: Total System Losses by Replacement Location – at Peak Load
(Megawatts)

One 750 MW CC Unit			Two 750 MW CC Units		
Alternate Location	**Total MW**	**Delta MW**	**Alternate Location**	**Total MW**	**Delta MW**
Base Scenario	1,739		Base Scenario	1,738	
Southwest	1,743	4	SW Metro	1,736	-2
Northwest	1,753	14	NW+Metro	1,743	5
Metro	1,725	-14	NW+SW	1,768	29

Note: Point of peak load is during 2020 Summer

Table 5: Total System Losses by Replacement Location – Shoulder Conditions
(Megawatts)

One 750 MW CC Unit			Two 750 MW CC Units		
Alternate Location	**Total MW**	**Delta MW**	**Alternate Location**	**Total MW**	**Delta MW**
Base Scenario	2,207		Base Scenario	2,199	
Southwest	2,221	13	SW+Metro	2,196	-3
Northwest	2,272	65	NW+Metro	2,256	57
Metro	2,180	-27	NW+SW	2,300	102

Note: Shoulder conditions is during 2020 Summer

These tables demonstrate that losses increase the farther away generation is located from the Twin Cities load center.

4. Summary

Our Reliability Study analyzed three alternate locations for siting replacement generation and concluded that siting replacement generation at locations other than Sherco will result in transmission upgrade costs that would not be needed if replacement generation is sited at Sherco. The number and cost of any required transmission upgrades is dependent on the location of the replacement generation, the amount of transmission capacity available from that location, and the amount of "other" generation that will be competing with the replacement generation for transmission capacity.

Additionally, because significant generation has been added to the MISO generation interconnection queue since we started our Reliability Study in early 2015, the costs we have estimated for alternate locations are likely low and less certain because of how the MISO system will evolve as a result. Finally, the further the replacement generation is sited from the Twin Cities load center, the higher the amount of losses the generation experiences – and while not specifically evaluated in our Study, we believe siting replacement generation in wind rich areas such as southwest Minnesota will "use up" transmission capacity that can be used for the installation of additional wind or other renewable generation.

D. Black Start Analysis

As explained in our March 16, 2015 Supplement, Sherco Units 1 and 2 play a significant role on our system and in the entire Upper Midwest. One of the key roles these Units play is in restarting the system in the event of a catastrophic loss of power to all or a significant part of a geographic area. Normally, the electric power used within a generating plant is provided from the station's own generators. If all of the plant's main generators are shutdown, station power is provided by drawing power from the transmission grid, which can be used to start the plant. However, during a wide-area outage, power from the grid will not be available. In the absence of grid power, a so-called "black start" needs to be performed to "bootstrap," or self-start the power grid into operation without the use of external resources.

We are required by NERC to maintain a plan to restart the system, which must be coordinated with neighboring utilities and is subject to acceptance by MISO. In this section, we discuss the considerations that go into black start planning, and our conclusion that other restoration paths, while less efficient, are viable with various equipment upgrades.

1. Overview

Black Start planning involves developing models, strategies and procedures to configure the system such that one or more generators can be brought online – and at the same time, picking-up sufficient customer load to satisfy the generator's minimum requirements for stability. This process sets up "islands" where part of the transmission and distribution systems in a geographic area begin serving at least part of the load in that area. Once we determine an island is stable, we can synchronize and reconnect/restore more generators and load, essentially expanding the island and restoring our interconnections with other utilities until the system is fully recovered. The longer the system is down, the harder it is to restore, so we work to determine the most efficient path(s) possible.[15]

We generally plan restoration assuming that the event that caused the outage caused no damage to the system. However, because this is a possibility, we must also plan alternate restoration paths that we can take in the event a portion of the system is damaged as part of the catastrophic event. We also must incorporate differing procedures based on the weather extremes in our geographic footprint. For example, any large generating unit that uses steam will take approximately one hour to wind down and fully stop operating. If ambient temperatures are cold, the water that remains in the Unit's pipes and boiler can freeze. Therefore, if we expect restoration of that Unit to take three or more hours, we may need to begin draining the pipes and boilers. If this occurs, our restoration of that generating unit will likely be delayed to the following day, after the unit goes through operational procedures that prepares it for a cold restart.

Sherco Unit 3 is the largest generating unit in the region and during a restoration event, we need it to provide the generating output necessary to restore customer load and the spinning reserves required for the NSP Island.[16] In the circumstance that a generator fails, Sherco Unit 3 has the capacity and the capability to ramp-up generation quickly to pick up the customer load that was lost by the failed generator. This becomes essential as the island grows, incorporating the neighboring utilities. However, Sherco Unit 3 is too large to be a Target Unit, so can only be started after we have at least one additional generator over-and-above the Initial Unit(s).

Our current plan gets from the Initial Unit(s) to Sherco Units 1 and 2 within a couple of hours. Because of their proximate location to Sherco Unit 3, the balance of the restoration plan is set in motion quickly to fully restore the system. As a steam unit, Sherco Unit 3 is impacted by the freeze potential we explained above if it takes longer than approximately four hours to power it up in the winter months. Therefore, getting

[15] The longer the system is down, equipment and facilities cool. Additional impacts include effects such as the fact that substation batteries will only keep the substations operational for a limited time. If the substation batteries deplete, we cannot easily isolate or energize the substation.

[16] In this case, the spinning reserves are the amount of additional generation that is on stand-by in the event that another generator within the island fails. To help ensure consistent availability and reliability of electricity during the restoration process, utilities keep generation capacity on reserve that can be accessed quickly if there is a disruption to the power supply. For example, if another generator or a major transmission line within the NSP/GRE/MP Island goes down, then NSP will access its reserve capacity at Sherco Unit 3 to compensate for that loss.

Sherco Unit 3 up and running quickly not only allows the Company to restore load faster and begin reaching out to neighboring utilities sooner – it also eliminates the concern of broader restoration delays associated with preventing the Unit from freezing.

2. *Planning Considerations*

Only certain types and sizes of generation are eligible to be considered Initial Units or Target Units. As noted previously, the Initial Unit(s) is the first generating unit that sets restoration in motion, and needs to be at least 110 MW and no more than 300 MW. It needs to be big enough to restore a larger Target Unit, but small enough to be able to start with an independent fuel source, such as fuel oil. Target Units are the generating units on the restoration path that are started by the Initial Unit(s). Eligible Target Units include coal, natural gas, hydro, and fuel oil – all of which are controllable and capable of both providing and absorbing reactive power. Renewable generation, such as solar and wind are not currently considered eligible Target Units due to their inherent intermittent nature, and their inability to provide or absorb reactive power. Nuclear units are also not eligible because they cannot vary their output, and can only come online after the balance of the system is fully stable.

When choosing a potential Target Unit as part of a black start study, we consider the following items (other than fuel source):

- Multiple generating units at the site
- Low minimum operating limits
- Ramp rate of the units
- How fast a unit can come on-line once it receives station power
- Unit's ability to act as a stabilizing unit in the island
- Amount of switching required in order to energize the unit

Special care is needed when energizing transmission lines during a system restoration due to the especially light loads present on the system. When lines are energized with little or no real power load, the charging current produces reactive power. We provide an example of how much reactive power may be needed when energizing an overhead transmission line in Table 6 below.

Table 6: Reactive Power Requirement for Energizing Overhead Transmission Lines

Transmission Voltage (kV)	MVAR per mile of line
69	0.011
115	0.033
230	0.125
345	0.164
500	0.770

Underground transmission lines produce even more reactive power that must be absorbed. The reactive power needs of an underground cable is *ten times* that of an overhead transmission line.

The same concern occurs when energizing transformers. The generation that is online must be able to absorb the reactive power injected into the system due to the energization of the transformer.

Table 7: Reactive Power Requirement for Energizing Transformers

Transformer Size (MVA)	MVAR Requirement
28	2.25
47	3.25
70	5.7
187	15
336	27-30
448	36
672	50.25

Before a line or transformer is energized, there must be sufficient generation MVAR capacity online to absorb the capacitive reactance produced by that line/transformer. If not balanced properly, it is easy to overwhelm the generator by collapsing its magnetic field, causing the generator to trip off-line, and potentially re-collapse the system.

When we begin to start-up motors and pumps at the next generating plant, the Initial Unit(s) must be capable of providing that reactive component back to the system in order to start the motors. Table 8 below outlines the amount of reactive power that is needed to start various sized motors at a typical power plant.

Table 8: Reactive Power Requirement for Starting Typical-Sized Generating Unit Motors

	Motor Start		Motor Running	
Motor HP	**MW Load**	**MVAR Load**	**MW Load**	**MVAR Load**
350	0.36	1.78	0.33	0.16
700	0.73	3.55	0.65	0.32
1500	1.55	7.61	1.4	0.68
2000	2.07	10.15	1.87	0.90
3000	3.11	15.23	2.8	1.35
6000	6.22	30.46	5.6	2.71

Starting large Target Units on our system requires around 30-40 MVAR of reactive power just to start the unit, which is substantial. The restoration path from the Initial Unit(s) to the Target Unit will inject an additional 75-110 MVAR of reactive power onto the system as transmission lines and transformers are energized, which the Initial Unit must absorb until the voltage reactors in our substations are energized.

The amount of MVARs needed for the restoration path will vary depending the on the path. Our current Black Start Plan requires an Initial Unit(s) of approximately 110 MW to 300 MW to restore our Target Unit – setting restoration in motion. Sherco Unit 3 is too large to be a viable Target Unit, because it is too large for the Initial Unit(s) to start, so is started later in the process. Additionally, as noted previously, nuclear units are not viable Target Units, nor are renewable generating units.

During this time, we must also be energizing transmission lines and transformers to bring customer load onto the system. We must balance the load and generation carefully, as without sufficient load, damage to our or customer equipment can occur from an overload of reactive power; if we energize lines and restore load too quickly, we can trip relays and will have to begin the process again. All substations on the current restoration path have emergency generators for maintaining full operating capability of switches, breakers, and relays at those substations. The emergency generators provide the AC power required to operate transformer pumps and fans as well as the transformer Load Tap Changers (LTCs). The emergency generators also maintain the battery chargers and ensure we maintain full battery capabilities. The substation batteries provide the DC power necessary for protective relaying, the motor operated disconnects, breaker trip coils, and communication equipment.

Generating units that interconnect with other utilities must also have a "sync scope," which is a device that measures frequency, voltage, and phase angle (Volts/VARs) to ensure the two islands (one on each side of the interconnection) are perfectly in sync before interconnecting. If they are not perfectly in sync, both islands could go back down and equipment could sustain damage. This becomes important when we start to reconnect our system with our neighboring systems, or when we bring Minnesota and Wisconsin or North Dakota and South Dakota back together.

3. Summary

Each of our current non-renewable generating plants plays a unique role in the black start process. In addition to the key roles currently played by Sherco Units 1 and 2, our **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** plant plays a key role in restoring the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** portion of our system. Altering the restoration path away from the Sherco site will require the addition of various equipment and/or facilities to other generating units and result in a longer restoration period. As we have discussed, restoration time is of greatest concern in winter/cold months.

The study determined that the existing **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** site as well as the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** site were workable for future restoration plans, provided additional emergency generations were added to the system. There is still a delay of several hours in getting from the Initial Unit(s) to Sherco Unit 3, since additional time will be needed to bring either **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** up to a stable minimal load level, before getting to Sherco.

The existing **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** plant requires more switching to be part of the restoration plan and has more underground cables in the area that would add a substantial level of complexity to the switching procedures. It is not advisable to utilize **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** as a Target Unit if **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** are available as well as the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** units. In order to utilize the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** plant, at least 13 new emergency generators would be needed, which would also not be cost-effective or practical from an operational perspective. In comparison, the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** would only require a combined five new emergency generators to be installed.

We outline the estimated costs of altering the current Sherco Units 1 and 2 restoration path in Table 9 below. We note that if generation is not replaced at Sherco, at least two of the new restoration paths would need to be used in order to ensure a viable path to Sherco Unit 3. For context, we also include the numbers of operating steps involved for each of the alternative paths, with greater numbers increasing the complexity and extending restoration time.

Table 9: Alternate Restoration Path – Estimated Cost and Operational Steps

Restoration Path	**Operational Steps** (Transmission)	**Estimated Additional Equipment Cost**
Current ME	22	
Current MW	16	
New Metro West 345 kV line	25	**[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
New Metro East 345/115 kV	32	**[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
Existing Paths with new Metro West 345 kV line	18	**[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
New Metro West 115 kV	24	**[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**

Note: as discussed below, additional costs may be involved with the alternative 115 kV paths.

Our current restoration path relies on the 345 kV transmission system. Some of the above alternatives rely on the 115 kV system. When considering whether or not to use a 115 kV path over a 345 kV path, we must consider the active and reactive power required to energize the line. The higher voltage (345 kV) lines have a higher reactive power requirement for energization, but the lower voltage (115 kV) lines have higher resistance, which results in more line losses, which requires the generator(s) to provide more power (MW) to energize the equivalent 115 kV path.

We provide as Table 10 below, an example of two lines from our system that demonstrates these differences.

Table 10: 115 kV Compared to 345 kV Resistance and Reactive Power

Line voltage	Line Resistance	Reactive Power MVAR/mile
Blue Lake – Black Dog 115 kV	0.009531	0.033
Blue Lake – Black Dog 345 kV	0.000578	0.164

In blackstart planning, we try to balance the role of active and reactive power in the generator, so that there is enough reactive power to energize the next piece of equipment – but not so much so to lose too much active power to line losses, which reduces the numbers of customers we can restore initially.

We also need to maintain control of the system voltage as the restoration paths are energized. The 115 kV path will have a lower VAR requirement, which can lead to lower bus voltages as more equipment is energized. In this case, capacitor banks may need to be energized to boost the voltage. Conversely, the 345 kV path will have a higher VAR requirement than the 115 kV path, which can lead to higher bus voltages and the need to energize existing voltage reactors in order to lower the bus voltages.

Our current Black Start Plan and the NSP System have been designed around the 345 kV system and the understanding that during light loads, the bus voltages may be higher at one end of the transmission line than the other. We therefore have reactors strategically installed throughout the system to help control these voltages. We also have capacitor banks on the 345 kV system for high load periods, where the bus voltages may become depressed. However, while the proposed 115 kV restoration paths currently have some capacitor banks installed, more may be needed, depending on where the new generation is sited and which restoration path is chosen.

Our proposal to construct a natural gas CC unit at the Sherco site would provide for our current and most efficient Black Start Plan to remain in place. The proposed Unit would be big enough to start Sherco Unit 3 without incurring restoration delays, and the additional equipment and/or facilities costs and operational complexities in other parts of the system.

E. Conclusion

While our **[TRADE SECRET BEGINS…** …**TRADE SECRET ENDS]** generation sites are good potential Target units for the restoration plan, there are costs associated with system upgrades as well as a delay in getting

Sherco Unit 3 started. The best solution from a restoration perspective would be to install black start eligible replacement generation onsite at Sherco.

IV. STUDY ASSUMPTIONS, INPUTS, and ALTERNATIVES

A. MISO Y2 Study

MISO Attachment Y2 studies are performed at the request of the generator owner considering retirement of a generating unit(s), and are performed in accordance with the MISO Business Practice Manuals. Their purpose is to determine how the system behaves in the absence of whatever generating unit(s) is being requested to be shut down. MISO runs scenarios with and without the generating units in-service to determine the impacts to the regional transmission system and to identify any potential issues. The identified issues are shared with an adhoc study group made up of neighboring transmission owners and other entities to determine if the issues are real, and what potential solutions are needed to mitigate all of the system deficiencies. MISO does not look at replacement generation alternatives unless they proposed as solutions by members of the adhoc group.

1. Assumptions

We provide a summary of the MISO Y2 Study assumptions and inputs below. The study assumptions are detailed beginning on page 8 of the NON-PUBLIC MISO *System Support Resource Attachment Y2 Study Final Report, Xcel Energy, The Sherburne County Generating Plan ("Sherco") Units 1 & 2*, dated August 28, 2015.

Unit Power Output. Each Sherco Units 1 and 2 are rated at 730 MW total output power. Station service load is 47.5 MW for each unit, making the net output per Unit 682.5 MW.[17]

Retirement Scenarios. The Company's March 11, 2015 Attachment Y2 Study request sought study of two retirement scenarios for Sherco Units 1 and 2 as follows:
(1) Both Sherco Units 1 and 2 on May 31, 2021, and
(2) Sherco Unit 2 on May 31, 2021 and Sherco Unit 1 on May 31, 2024.

Study Models. Studies were performed using the following power flow models:
Scenario 1:

- 2021 Summer Peak (MTEP15_2020 Summer Peak starting point)

[17] 2015-2016 UCAP Unit Ratings: Sherco Unit 1 – 696.1 MW; Sherco Unit 2 685.8 MW.

- 2021 Shoulder (MTEP15_2020 Shoulder 90% wind starting point)
- 2021 Winter Peak (MTEP15_2020 Winter Peak starting point)
- 2025 Summer Peak (MTEP15_2025 Summer Peak) Scenario 2:
- 2021 Summer Peak (MTEP15_2020 Summer Peak starting point)
- 2021 Shoulder (MTEP15_2020 Shoulder 90% wind starting point)
- 2021 Winter Peak (MTEP15_2020 Winter Peak starting point)
- 2025 Summer Peak (MTEP15_2025 Summer Peak)
- 2024 Shoulder (MTEP14_2024 Shoulder)

For the model, two sub-scenarios were created which represent the "before" and "after" generator retirements for each retirement scenario. The most relevant 2014 Security Constrained Economic Dispatch (SCED) input data from MTEP14 series was used and updated to reflect conditions in MTEP15 series models.

Model Assumptions - Generation. Units for which an Attachment Y had been completed during the relevant period were modeled as offline. Additionally, Attachment Y Units whose suspensions end before 2020 were modeled in-service.

Model Assumptions – Transmission. Significant transmission projects in service prior to the potential retirement dates were as follows:

- MTEP Project 3831 Great Northern Transmission Line (June 2020). To be added to MTEP14 2024SSH model only, MTEP15 models will have it already.
- MTEP Project 7910 Mud Lake – Brainerd 5L upgrade. Minnesota Power confirmed expected I/S date to be in 2019.
- MTEP Project 7913 Little Falls – Langola Tap – St. Stephen (115 kV) upgrade. Minnesota Power confirmed expected in-service date to be in 2019.
- MTEP Project 3127 N La Crosse – N Madison – Cardinal – Eden – Hickory Creek 345 kV. To be added to MTEP15 2020SUM and MTEP15 2020SSH only, later models already have them.

Additionally, Minnesota Power (MP) provided topology updates to MTEP14-2024SSH and a correction to all cases for its Silver Bay Generation and Iron Range-Forbes 230kV Line summer rating (summer cases only). Finally, each Units station service load was disconnected in the "after" as part of the retirement of the corresponding Unit(s), and the Xcel Energy (XEL) area slack bus was changed due to the potential retirement of Sherco Unit 2.

2. Criteria and Methodology

PTI PSS/E was used to perform AC contingency analysis. Cases were solved with automatic control of LTCs, phase shifters, DC taps, switched shunts enabled (regulating), and area interchange disabled. Contingency analysis was performed on before and after cases. The results were compared to determine if there were any criteria violations due to the Unit(s) change of status.

The *Steady State Thermal* and *Steady State Voltage* Planning Criteria for each Transmission Owner (XEL, Great River Energy (GRE), MP, American Transmission Company (ATC), Dairyland Power Cooperative (DPC), Southern Minnesota Municipal Power Agency (SMMPA), and Ottertail Power (OTP)) were applied.

MISO Transmission Planning Business Process Manuals – SSR Criteria. As specified in the MISO BPM-020-R12, (Section 6.2 beginning on page 133)[18] the System Support Resource criteria for determining if an identified facility is impacted by the suspension of the units will be:

- Under system intact and category B contingencies, branch thermal violations are only valid if the flow increase on the element in the "after" suspension scenario is equal to or greater than:
    a) 5 percent of the "to-be-retired" unit(s) MW amount (i.e. 5% PTDF) for a "base" violation compared with the "before" suspension scenario, or
    b) 3 percent of the "to-be-retired" unit(s) amount (i.e. 3% OTDF) for a "contingency" violation compared with the "before" suspension scenario.
- Under system intact and category B contingencies, high and low voltage violations are only valid if the change in voltage is greater than 1% as compared to the "before" suspension voltage calculation.
- Under category C contingencies, for the valid thermal and voltage violations as specified above, generation re-dispatch, system reconfiguration, or load shedding were considered if applicable.
- Angle/voltage stability studies will be performed if necessary.

3. Summary of Retirement Scenario Cases

Tables 11, 12 and 13 below provide summaries of the Case results, as they relate to NERC Event Categories. We note that Case 1 is Sherco Units 1 and 2 out of service

[18] MISO Business Practice Manual BPM-020 can be found at https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

and Case 2 is Sherco Unit 2 out of service. In order to make the results more easily understandable, we have included a brief definition of the NERC Event Categories in the Table 14 immediately following our summary of the Case results.

Table 11: Scenario 1 Case Summary

	Events/Violations		
NERC Event Category	**Summer Peak**	**Shoulder**	**Winter Peak**
P1		84/84 Thermal (MP) 2/2 Line Loading (MP) 119/907 Voltage (MP) 99/110 Voltage (XEL) 5/5 Voltage (GRE) 6/11 Voltage (*resolved by switching on local capacitor banks*) 2/3 Voltage (*addressed within GRE service area*)	
P2		2/2 Line Loading (MP) 119/907 Voltage (MP) 99/110 Voltage (XEL) 5/5 Voltage (GRE) 3/21 Voltage (*resolved by MTEP 9064*)	1/1 Thermal (MP) 2/2 Voltage (*addressed by transferring feeder load onto adjacent sources*)
P3		1/1 Thermal (XEL) 84/84 Thermal (MP) 97/142 Voltage (XEL) 119/907 Voltage (MP) 99/110 Voltage (XEL)	
P4		3/21 Voltage (*resolved by MTEP 9064*)	
P5		99/110 Voltage (XEL) 5/5 Voltage (GRE) 6/11 Voltage (*resolved by switching on local capacitor banks*) 1/3 Voltage (*resolved by Coal Creek generation reduction*)	1/1 Voltage (GRE – *resolved by MTEP 4380*)
P6	4 Voltage (XEL)	97/142 Voltage (XEL) 99/110 Voltage (XEL)	
P7		99/110 Voltage (XEL) 6/11 Voltage (*resolved by switching on local capacitor banks*)	

Table 12: Scenario 2 Case Summary

	Events/Violations		
NERC Event Category	**Summer Peak**	**Shoulder**	**Winter Peak**
P1		9/13 Voltage (XEL)	
P2		9/13 Voltage (XEL) 2/2 Voltage (GRE – *resolved by MTEP 4380*)	1/1 Thermal (MP)
P3		9/13 Voltage (XEL) 14/549 Voltage (MP) 6/11 Voltage (MP) 59/59 Thermal (MP)	
P4			
P5		2/2 Voltage (GRE – *resolved by MTEP 4380*)	
P6	3/3 Voltage (XEL)		
P7			

Table 13: Shared Cases (Scenarios 1 and 2) Summary

	Events/Violations		
NERC Event Category	**Summer Peak**	**Shoulder**	**Winter Peak**
P1	2/2 Voltage (GRE)		
P2			
P3		5/1 Thermal (XEL) 2/2 Thermal (MP) 8/10 Voltage (XEL) 4/7 Voltage (MP)	
P4			
P5			
P6		8/10 Voltage (XEL)	
P7			

Table 14: Abbreviated List of NERC Event Category Definitions[19]

P1	Single Contingency – Loss of one of the following: * Generator * Transmission Circuit * Transformer * Shunt Device * Single Pole of a DC line
P2	Single Contingency – * Opening of a line section w/o a fault * Bus Section fault * Internal Breaker fault (non-Bus-tie-Breaker) * Internal Breaker Fault (bus-tie Breaker)
P3	Multiple Contingency – Loss of one of the following: * Generator * Transmission circuit * Transformer * Shunt Device * Single pole of a DC line
P4	Multiple Contingency – (Fault plus stuck breaker) Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: * Generator * Transmission Circuit * Transformer * Shunt Device * Bus Section * Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus
P5	Multiple Contingency (*Fault plus relay failure to operate)* – Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following: * Generator * Transmission Circuit * Transformer * Shunt Device * Bus Section
P6	Multiple Contingency (*two overlapping single contingencies)* – Loss of one of the following: * Transmission Circuit * Transformer * Shunt Device * Single pole of a DC line
P7	Multiple Contingency (*Common Structure)* – The loss of: * Any two adjacent (vertically or horizontally) circuits on common structure * Loss of a bipolar DC line

[19] For a full description of NERC's event categories, *please see*: http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf beginning at page 8.

4. *Special Voltage Stability Study – Monticello Nuclear*

As noted previously, due to the electrical proximity between the Monticello Nuclear generating plan and Sherco, the voltages at Monticello's 115 kV and 345 kV buses received special attention. This special study was to determine whether Monticello's voltage will remain within the plant's NPIR limits at all times, and whether the region around Monticello would be at risk of voltage collapse under certain power transfer scenarios.

Model Preparation. The voltage results of the steady state power flow showed a significant number of voltage violations in the 2021 shoulder case compared to the number of voltage violations in the 2021 summer case in the Twin Cities area, which can be attributed to the number of online units in each case. Only few units in the Twin Cities area are online in the shoulder case, however all the units in the Twin Cities are online in the summer case. The presence of these units supports the voltage stability in the summer case compared to the shoulder case.[20] For this reason, MISO determined the 'Source' and the 'Sink' to implement the power transfer needed for the voltage stability study based on the 2021 shoulder case. All the online units within the Twin Cities area were used as the 'Sink' subsystem (their output was reduced) and all the units outside the Twin Cities are the 'Source' subsystem.

Contingencies. The voltage stability studies selected the events observed to cause the highest voltage drop at Monticello combined with the loss of Sherco Unit 3 to implement NERC P3 contingencies.

Methodology. MISO used the PSS-E PV Analysis tool. For the base case, all taps and switched shunts were allowed for automatic adjustments and Area interchange control was disabled. For the contingency case, all taps and switched shunts were locked and Area interchange control was disabled. The branch loading check (thermal violations check) was disabled to study only the impact of the power transfer on the voltage, and the Machine active power limits were honored.

Verification of the Voltage Collapse Conditions. To verify that power flow solution blows-up due to true voltage collapse conditions and not due to some numerical issues, numerous switched shunt actions were verified right before reaching the blow-up status. All online generators within the Twin Cities reached their Qmax limit, which proved that the case blow-up as the power transfer reached the knee of the P-V curve as shown.

[20] The status of each unit in that area was determined automatically during the SCED process.

Transient Stability. Considering the size of the two Sherco Units and due to their proximity from the two nuclear plants (Monticello and Prairie Island) that have special frequency requirements, a transient stability assessment was needed. This assessment was done to study the impact of the retirement of Sherco Units 1 and 2 in 2021. A similar study must be conducted if the Company decides to retire only one of the Sherco Units 1 and 2.

MISO used the dynamic model MTEP14-2019 Summer Shoulder with specific assumptions including Sherco unit 1 and unit 2 kept offline and all of the applicable generation and transmission assumptions listed earlier. As per MTEP14 Transient Stability Assessment, the MISO West Sub-region is more stressed during high transfers in shoulder periods.[21] After applying all the above changes, SCED was performed on the case. Ten disturbances selected from the MTEP14 study in addition to three disturbances provided by GRE were each simulated for 20 seconds. PSS-E version 32 was used in simulating these disturbances. Again, the Transmission Owner Planning Criteria and Monticello NPIR were considered; the rotor angle, bus voltage, and bus frequency channels in XEL, MP, GRE, and MH were selected.

5. *Limitations*

The MISO Y2 study is a "first come, first served" study where only generators that have already requested to retire are considered when performing the study. MISO does not attempt to predict which generators they believe will retire in the future. With the Clean Power Plan, it is very likely additional generators not included in the MISO Y2 Study performed for Sherco Unit 1 and 2 scenarios will be retired, which could impact Sherco Unit 1 and 2 retirement.

B. Xcel Energy Transmission Reliability Study

1. *Sherco 1 Study Replacement Scenarios*

We initiated our Reliability Study to further investigate the transmission impacts associated with replacement generation for one or two Sherco units being located at various locations on the NSP System. We identified three potential locations that include both greenfield and brownfield conditions. Our considerations in choosing the locations include proximity to existing transmission facilities, generation facilities, and natural gas pipelines – and other factors, such as potential land availability needed to accommodate new generation. The alternative locations are as follows:

[21] The MTEP15 dynamic model was not yet ready.

- Metro
- Southwest
- Northwest

2. *Sherco 1 and 2 Study Replacement Scenarios*

We considered nine scenarios for Sherco Units 1 and 2 replacement:

1. CAPCON 700 MW, Metro 600 MW[22]
2. CAPCON 700 MW, Northwest 700 MW
3. CAPCON 700 MW, Southwest 700 MW
4. Northwest 700 MW, Metro 600 MW
5. Northwest 700 MW, Southwest 700 MW
6. Northwest 1,400 MW
7. Southwest 700 MW, Metro 600 MW
8. Southwest 1,400 MW
9. Metro 1,200 MW

Linear power flow methods (DCCC) were used to perform contingency analysis on each of the nine scenarios for the summer and shoulder peak system conditions. Based on these thermal results potential mitigation was identified and estimated.

Four scenarios were selected for further analysis based internal stakeholder input.

1. Southwest 750 MW, Metro 750 MW
2. Northwest 750 MW, Metro 750 MW
3. Northwest 750 MW, Southwest 750 MW
4. Sherburne County 1,500 MW (Stability Only)

3. *Study Methodology*

The replacement scenarios were evaluated for the study year 2020. Summer peak and shoulder peak cases were developed based on the MISO MTEP14, 2019 summer peak and summer shoulder cases. These cases were updated from 2019 to 2020 by adding in the MISO MTEP14 Appendix A projects with an in-service date before June 1, 2020. In addition to transmission projects, all generator projects located in the MISO DPP study cycle through the DPP 2014 February benchmark cases that were

[22] CAPCON is the generating resources being added to the NSP System as a result of the Competitive Acquisition proceeding in Docket No. E002/CN-12-1240. These resource include: Mankato Energy Center II, Aurora Solar, and Black Dog 6.

located in the region were added to the cases. The CC generation was dispatched based on a merit order in the shoulder peak cases.

a. Steady State Analysis

Summer peak and shoulder cases were evaluated for steady-state thermal and voltage issues using PSSE version 33 and PSSMUST version 10.2 Contingency criteria was based on the MTEP14 contingencies files.

- NERC Category A with system intact (no contingencies)
- NERC Category B contingencies
  - Single element outages, at buses with a nominal voltage of 100 kV and above, in the following areas: WEC (area 295), XEL (area 600), MP (area 608), SMMPA (area 613), GRE (area 615), OTP (area 620), ITCM (area 627), MEC (area 635), WAPA (area 652), MDU (area 661), DPC (area 680), ALTE (area 694), WPS (area 696), MGE (area 697), UPPC (area 698)
  - multiple-element outages initiated by a fault with normal clearing such as multi-terminal lines, in Iowa, North Dakota, South Dakota, Minnesota and Wisconsin.
- NERC Category C
  - NERC Category C events, in Iowa, North Dakota, South Dakota, Minnesota and Wisconsin.

Monitored elements for each of the areas are described in the Table 15 below.

Table 15: Monitored System Elements

Owner/ Area	Monitored Facilities	Thermal Limits		Voltage Limits	
		Pre-Disturbance	Post-Disturbance	Pre-Disturbance	Post-Disturbance
ATCLLC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
DPC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
GRE	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.92
ITCM	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.07/1.05/0.93
MDU	57 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
MEC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.96/0.95	1.05/0.96/0.95
MHEB	69 kV and above	100% of Rate A	100% of Rate B	1.12/1.1/1.07/1.05/1.04/0.99/0.97/0.96/0.95	1.15/1.1/0.94/0.9
MP	69 kV and above	100% of Rate A	100% of Rate B	1.05/1.0	1.1/0.95
OTP	40 kV and above	100% of Rate A	100% of Rate B	1.07/1.05/0.97	1.1/0.92
SMMPA	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
WAPA	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
XEL	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.92
Monticello	345 kV	100% of Rate A	100% of Rate B	1.0492/0.9914	1.0492/0.9914
Monticello	115 kV	100% of Rate A	100% of Rate B	1.05/1.0087	1.05/1.0087
Prairie Island	345 kV	100% of Rate A	100% of Rate B	1.05/0.9911	1.05/0.9911
Prairie Island	161 kV	100% of Rate A	100% of Rate B	1.05/0.9969	1.05/0.9969

A branch is considered thermally constrained if the following conditions are met.

1. The branch is loaded above its applicable normal or emergency rating, and
2. A replacement scenario generator has a larger than 5% DF on the overloaded facility under system intact or post contingent, or
3. The impact of the replacement scenario is greater than 10% of the applicable rating of the overloaded facility

A bus is considered a voltage constraint if both of the following conditions are met.

1. The bus voltage is outside of applicable normal or emergency limits, and
2. The change in bus voltage is greater than 0.01 per unit.

b. System Loss Analysis

Real power losses for the study were based on a comparison of total system losses from the benchmark base cases and the replacement scenario cases.

c. Reactive Power Analysis

Reactive power production for the study was studied by comparing the amount of reactive power produced in the Xcel Energy area in the benchmark base case compared to the replacement scenario cases.

4. Transient Stability

Transient stability was performed using PSSE version 32.2. Transient stability analysis was performed using the MTEP14 stability package. Disturbances were simulated on the benchmark case and the study cases to identify any significant impacts.

a. Disturbance Criteria

The stability simulations as part of this study took into account both regional and local contingencies. For local contingencies generic clearing times were used and the fault admittances for single line to ground faults were estimated by assuming the Thevenin impedance of the positive, negative, and zero sequence networks at the point of the fault are equal.

b. Performance Criteria

Simulation results were evaluated using the MRO System Performance Table in the MRO System Performance Standard TPL-503-MRO-01. Transient voltages must be within the default limits of 0.70-1.20 per unit with the exception of specific buses, areas or companies that have different requirements. All machine rotor angle oscillations must be positively damped with a minimum damping factor of 5% for disturbances with a fault, or 10% for line trips without a fault.

Transient apparent impedance swings on all lines were monitored after fault clearing using the mrely1 user written model. The mrely1 model uses a generic three-zone mho characteristic. Apparent impedance transient swings into the inner two zones are unacceptable for NERC Category B disturbances. Apparent impedance transient swings into the inner two zones of distance relays are unacceptable for NERC

Category C disturbances, unless a relay trip will not result in instability (including voltage instability), uncontrolled separation, or cascading outages.

5. *Mitigation Cost Assumptions*

Unit cost tables were developed for the overhead transmission lines, substation, transformers, and any reactive power instillations that were needed for the study effort. These costs were based on new construction and in 2015 dollars.

6. *Limitations*

The Reliability Study, when it was initiated in early 2015, included a number of projects from the MISO interconnection queue that were assumed to be going into service at the time the study was performed. Because of this, any changes to the MISO Queue could have an impact on the conclusions of the our Reliability Study – with the likely outcome of increasing the identified estimated interconnection costs for projects analyzed.

C. Black Start Analysis

1. *Assumptions and Inputs*

The primary purpose of the study was to investigate the impacts of retiring Sherco Units 1 and 2, on the NSP Power System Restoration Plan. The study looked at future blackout scenarios where Sherco Units 1 and 2 are not available for restoration efforts. The intent was to identify potential new Target Units and the associated restoration paths for those units. The Study also identified potential challenges with the various scenarios and what potential upgrades would be required to make those viable options for future restoration plans. The Study assumed that the natural gas pipeline supplies for potential new Target Units is adequate to start and run the plants for the restoration plan.

The Black Start Study utilized the same study models that were created for the Xcel Energy Transmission Reliability Study, modified for the blackout scenario base cases, from which multiple Target Units and associated restoration paths were studied. Due to the proximity from where the proposed replacement generation in the model was sited to the primary Twin Cities load center, we eliminated the Northwest generation and the Southwest generation locations – only studying the Metro location and other existing plant locations.

2. *Alternatives Examined*

We analyzed four new potential restoration paths: (1) a 345kV path to **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**, (2) a 115kV path to **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** with underground cable, (3) another 115kV path to **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** using overhead lines, and then (4) a combination 345/115 kV path to **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**. After the generation was started at each of the new Target Units, the restoration paths were energized to Sherco.

3. *Study Methodology*

To demonstrate generator capability is adequate to perform its black start functions, the Initial and Target Units must stay within real and reactive limitations based on that unit's most recent D-curve, or operating limits.[23] Unit loading must be dispatched so that the contingent loss of one of the units will not cause the other online units to exceed their real and reactive power capabilities or their governor response capability.

The Initial Unit(s) requires that the terminal voltage of the generators must be 13.1 kV (95%), if the loading on that generator exceeds 10 MW. A temporary reduction to 12.8 kV (93%) is allowed for unit output less than 10 MW. Due to these restrictions and the current tap settings on the generator step-up transformers (GSU), there are additional voltage constraints for the 115 kV bus.

For the Initial and Target Units to be considered capable of performing their functions within the our Black Start Plan, they must be able to energize at least one restoration path between the black start substation, and the new Target Unit. The Initial Unit(s) must be able to start the new Target Unit and then continue the restoration path to the Sherco substation and be able to complete the Sherco Unit 3 load start-up sequence without causing violations to the above criteria.

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[23] In addition to producing capacity and energy to meet customer load requirements, generating units help control voltage on the grid by producing and absorbing reactive power (MVAR); *producing* MVAR helps *increase* the voltage, and *absorbing* MVAR helps *decrease* the voltage. When a generator is producing or absorbing reactive power, it cannot produce its maximum MW output because its operating capability is partially "used up" from producing or absorbing reactive power. Therefore, a generating unit's D-curve shows the operating limits for a generating unit in terms of the relationship between the active power (MW) it is producing and the reactive power it is either producing or absorbing – and how they are balanced within the unit's maximum operating limits.

To effectively analyze the restoration paths, we created scripts to simulate the major switching steps outlined for each switching step along the restoration path. For each major step in the restoration path development, we monitored bus voltages at key transmission substations and the Initial Units' real and reactive power output. Both the steady-state and immediate post-switching (time 0+) results were displayed for each step, as outlined in Table 16 below.

Table 16: Steady-State and Immediate Post-Switching Results

	Switching Limits		Steady State Limits	
	Low Voltage	**High Voltage**	**Low Voltage**	**High Voltage**
All buses	0.90 pu	1.05 pu	0.95 pu	1.05 pu

We did not actively monitor transmission equipment loadings because the amount of load energized to support each restoration path did not exceed the lowest rating of any one piece of series connected equipment.

4. *General Findings*

The Study determined that **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** would not be a good Target Unit due to the difficulty in switching to get there for the operators, as well as the number of emergency generators that would need to be added to the system. The overhead path, while longer and requiring an additional generator to be installed, was a better option than the underground path. The reactive power requirements for the underground path were a challenge and could require an additional Initial Unit(s).

The Metro East 345/115 kV path and the Metro West 345 kV paths were the preferred paths to the alternate Target Units. However the process of bringing the Target Unit online and up to minimum load will delay the restart of Sherco Unit 3, and the restoration of off-site station power to both Monticello and Prairie Island. Importantly, the existing paths to Sherco Units 1 and 2 or the new proposed onsite CC unit allows restoration of offsite station power to both nuclear plants and start-up procedures for Sherco Unit 3 in the most efficient timeframe.

System Support Resource Attachment Y2 Study

Final Report

Xcel Energy

The Sherburne County Generating Plant ("Sherco") Units 1 & 2

August 28, 2015

Redacted

MISO

P.O. Box 4202
Carmel, IN 46082-4202
Tel.: 317-249-5400 Fax: 317-249-5703
http://www.misoenergy.org

Siemens PTI Report Number: R066-15

Sherco 1 Replacement Power Study

Prepared for

Xcel Energy Services

Submitted by:
Greg Woodworth, Sr. Staff Consultant
Douglas R. Brown, Sr. Manager
Yaming Zhu, Principal Consultant
Rajat Majumder, Sr. Staff Consultant
William Yannan Wang, Consultant
Kavita Shenoi, Senior Consultant

January 22, 2016

Siemens PTI Project P/21-113979

Siemens Industry, Inc.
Siemens Power Technologies International
10900 Wayzata Boulevard
Minnetonka, Minnesota 55305 USA
Tel: +1 (952) 607-2270 • Fax: +1 (518) 346-2777
www.siemens.com/power-technologies

SIEMENS

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Submitted by:
Greg Woodworth, Sr. Staff Consultant
Douglas R. Brown, Sr. Manager
Yaming Zhu, Principal Consultant
William Yannan Wang, Consultant
Kavita Shenoi, Senior Consultant

January 22, 2016

Siemens PTI Project Number P/21-113979

Siemens Industry, Inc.
Siemens Power Technologies International
10900 Wayzata Boulevard
Minnetonka, Minnesota 55305 USA
Tel: +1 (952) 607-2270 • Fax: +1 (518) 346-2777
www.siemens.com/power-technologies

SIEMENS

Attachment E
Estimated Rate Impacts

In order to show the impacts of our plan on customer rates and bills, we have included an estimated rate impact analysis of our Updated 2015 and Current Preferred Plan below that includes the breakdown of anticipated increases by customer class. The estimated customer impacts are shown for the five-year period from 2016-2020 at the Minnesota customer class levels. In this Attachment, we present the results of that analysis and discuss the methodology we used to calculate the revenue requirements associated with our Updated 2015 and Current Preferred Plans.

A. Rate Forecast Methodology

To calculate the rate impacts of the Updated 2015 and Current Preferred Plans, we started with the 2016 Budget forecast of total revenue requirements for 2016-2020, developed in July 2015. This is the forecast that formed the basis for the 2016 MN Electric Rate Case (Docket No. E002/GR-15-826) filed in November 2015. [1]

The assumption differences between the Rate Case, the Updated 2015 Plan, and the Current Preferred Plan are as follows:

1. *Rate Case:* Our rate case model includes the following resource additions:

   - 287 MW of solar Power Purchase Agreements (PPA) in 2017, made up of the 100 MW Aurora distributed solar project (Docket No. E002/M-15-330) and 187 MW from our Solar Request for Proposals (Docket No. E002/M-14-162)
   - Updated Community Solar Gardens forecast we reflected in our March 2015 Supplement, totaling over 200 MW by 2020
   - Rooftop solar additions of 9 MW per year through 2020, reflecting Solar Rewards and Made in Minnesota projects
   - 200 MW Courtenay wind project, expected to achieve commercial operation by end of 2016
   - 200 MW Odell wind PPA, expected to achieve commercial operation in 2016

[1] The Company filed an electric rate case application for a 2016-2018 multi-year rate plan in November, 2015. The information contained in that filing includes specific assumptions and adjustments for ratemaking, and will therefore differ from the estimated rate impact information provided in this filing.

- 600 MW of non-Production Tax Credit (PTC) PPA wind, reflecting the proposal in our Updated 2015 plan, before the extension of the PTC
- 345 MW Calpine Corporation Mankato Energy Center natural gas combined cycle project, expected in-service no later than 2019
- 232 MW Xcel Energy Black Dog natural gas combustion turbine project, expected to achieve commercial operation no later than 2019
- Sherco Units 1 and 2 operational through 2030

These changes are summarized in Table 1 below.

Table 1: 2016 Rate Case Resource Additions

	Rate Case				
	2016	2017	2018	2019	2020
Solar PPA MW	0	287	0	0	0
Solar Gardens MW	33	36	40	44	49
Rooftop Solar MW	9	9	9	9	9
Owned Wind w/ PTCs MW	200	0	0	0	0
PPA Wind w/ PTCs MW	200	0	0	0	0
PPA Wind wo/ PTCs MW	0	0	0	0	600
Black Dog MW	0	0	0	232	0
Calpine expansion PPA MW	0	0	0	345	0

2. *Updated 2015 Plan*

The Updated 2015 Plan reflects the same resources shown in the rate case above, with the exceptions of the 600 MW of non-PTC PPA wind in 2020 switches to PTC wind in the Updated 2015 Plan, to reflect the extension of the renewable energy tax credits.

The changes from the Rate Case forecast to the Updated 2015 Plan are shown in Table 2 below.

Table 2: Changes from 2016 Rate Case to Updated 2015 Plan

	2016	2017	2018	2019	2020
PPA Wind w/ PTCs MW	-	-	-	-	+600
PPA Wind wo/ PTCs MW	-	-	-	-	-600

3. *Current Preferred Plan*

The resource additions in our Current Preferred Plan reflect all the changes described above, as well as the resource adjustments described below and shown in Table 3 below:

- Ceasing operations of Sherco Unit 1 in 2026 and Sherco Unit 2 in 2023
- 200 MW of owned solar, added in 2018 and in 2020
- 200 MW of PPA solar, added in 2018 and in 2020
- 400 MW of owned PTC wind in 2018
- 400 MW of PPA wind with PTC in 2018

The changes from the Updated 2015 Plan to the Current Preferred Plan are shown in Table 3 below.

Table 3: Changes from Updated 2015 Plan to Current Preferred Plan

	2016	2017	2018	2019	2020
Owned Solar MW	-	-	+100	-	+100
Solar PPA MW	-	-	+100	-	+100
Owned Wind w/ PTCs MW	-	-	+400	-	-
PPA Wind w/ PTCs MW	-	-	+400	-	-

Table 4 below summarizes all the resources included in our Revenue Requirements analysis of the Current Preferred Plan costs.

Table 4: Current Preferred Plan Resources

	Current Preferred Plan				
	2016	2017	2018	2019	2020
Owned Solar MW	-	-	100	0	100
Solar PPA MW	0	287	100	0	100
Solar Gardens MW	33	36	40	44	49
Rooftop Solar MW	9	9	9	9	9
Owned Wind w/ PTCs MW	200	0	400	0	0
Owned Wind wo/ PTCs MW	0	0	0	0	0
PPA Wind w/ PTCs MW	200	0	400	0	0
PPA Wind wo/ PTCs MW	0	0	0	0	0
Black Dog MW	0	0	0	232	0
Calpine expansion PPA MW	0	0	0	345	0

B. Estimated Rate Impacts by Class per Year

We note that a detailed analysis of rate impacts in a resource planning process with long-time horizons is difficult to produce due to changes in our rates and resource needs that will occur over time. Because of the simplifying assumptions made in both the calculation methodology and the input variables, these estimated impacts may not correspond with actual rates that the Commission sets for various rate classes in the future.

To estimate customer impacts for the immediate five-year period, we estimated revenue requirements similar to a Jurisdictional Cost of Service (JCOSS) for each year, and then performed an estimated Class Cost of Service (CCOSS) analysis – both of which required us to make a number of assumptions.

To determine the JCOSS, we had to make a number of assumptions, including the following:

- Full recovery of the Company's internal five-year forecasts of capital, O&M, and sales,[2]
- Return on Equity (ROE) requested in Docket No. E002/GR-15-826 of 10.00 percent,
- A forecast of debt and equity ratios and debt rates appropriate for the five-year modeling term,
- Estimated typical and precedential regulatory adjustments made in rate cases, such as Advertising, Association Dues, Corporate Aviation, Customer Deposits, Foundation Administration, Incentive Compensation, Investor Relations, the Monticello Extended Power Uprate (EPU) prudence decision from Docket No. E002/CI-13-754, Nobles Amounts over the Certificate of Need, the Prairie Island EPU Amortization, Removal of Non-Asset Trading, and the Sherco Life Extension,

We added the following adjustments appropriate to the Updated 2015 Plan scenario and to the Current Preferred Plan.

Updated 2015 Plan scenario:

- The generation resources described in Table 2 above were modeled to create a fuel forecast. The differences in purchased energy and purchased capacity were added as expenses to the revenue requirements model. Since purchased energy is recovered through the fuel clause, we also assumed an equal amount of fuel

[2] Data as of August, 2015.

clause revenue.

Current Preferred Plan scenario:

- The generation resources described in Table 4 above were modeled to create a fuel forecast. The differences in purchased energy and purchased capacity were added as expenses to the revenue requirements model. Since purchased energy is recovered through the fuel clause, we also assumed an equal amount of fuel clause revenue.
- We estimated rate base, operating expenses, and tax credits related to the owned wind and solar resources and added them to the revenue requirements model.
- We estimated book and tax depreciation expenses, associated balances, and associated property taxes related to an earlier retirement of Sherco Units 1 and 2. These were added to the revenue requirements model.
- We estimated changes to variable O&M at coal, gas combined cycle, and gas combustion turbine plants due to the different fuel dispatch assumptions associated with the generation resource assumptions and adjusted the revenue requirements model.

We caution, however, that this information should not be interpreted as directly comparable to the customer rate impact information we provide as part of a rate case filing for reasons such as the following:

- The internal forecast for 2019-2020 is not prepared at the level of detail necessary for support of a rate case,
- While the forecast includes typical regulatory adjustments, we have not attempted to remove one-time effects or other one-time adjustments that are not specifically known at this time,
- We have made no determination of a rate case filing schedule over this period; the forecast provided assumes full recovery of annual deficiencies, suggesting a full rate case annually, and
- All factors of the Cost of Capital, including debt rates, return on equity, and debt-equity ratios, are subject to change through a rate case.

C. Determining Class Rate Impacts

After the Minnesota jurisdiction projected total revenue requirements for the period are developed, the costs are allocated to customer class based on the approved CCOSS allocation methods from the Company's last rate case order (Docket No.

E002/GR-13-868). Below, we provide detail on the Commission approved methods for allocating all production-related costs.

1. *Allocation of Production Related Costs*

a. Capital-Related Production Costs

When allocating capital-related production costs, the Company uses the plant stratification approach approved by the Commission in the Company's last five rate cases.

The plant stratification approach begins by comparing the replacement cost of each type of generation plant (fossil, combined cycle, etc.) to the replacement cost of a combustion turbine. Combustion turbines are 100 percent capacity/demand-related since they are the generation source with the lowest capital cost and the highest operating cost. For each generation type, the percent of total generation costs that exceeds the cost of combustion turbine peaking plant are classified as being energy-related. These costs are in excess of the capacity/demand-related portion, and as such, were not incurred to obtain capacity, but rather to obtain lower cost energy.

We show the Commission-approved plant stratification analysis that we applied to capital-related production costs for each plant type in Table 5 below:

Table 5: Stratification Analysis by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity/Demand Percentage	Energy Percentage
Combustion Turbine	$792	$792 / $792	100.0%	0.0%
Fossil	$2,022	$792 / $2,022	39.2%	60.8%
Nuclear	$4,146	$792 / $4,146	19.1%	80.9%
Combined Cycle	$1,037	$792 / $1,037	76.3%	23.7%
Wind	$14,894	$792 / $14,894	5.3%	94.7%
Solar	$8,182	$792 / $8,182	9.7%	90.3%

After production capital costs for each type of generation plant are split into capacity-related and energy related components based on the percentages shown in Table 5 above, those costs that have been classified as being energy-related are allocated to class using the E8760 energy allocator. The E8760 allocator is calculated by taking the forecast hourly load for each of the 8,760 hours of the test year for each customer class, then weighting the hourly load by the forecasted hourly marginal energy cost in each respective hour. The approved E8760 allocator from the last rate case order is shown in Table 6 below:

Table 6: Approved E8760 Energy Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	29.24%	3.33%	67.01%	0.42%

The capital costs that have been classified as being capacity or demand-related are allocated to customer class using the Commission-approved D10S capacity allocator. The D10S allocator is simply each class's load that is coincident with the NSP System peak load. The Commission approved D10S class allocator percentages are shown in Table 7 below:

Table 7: Approved D10S Capacity Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	34.86%	3.72%	61.42%	0.00%

b. Fuel and Purchased Energy Expenses

These costs are allocated to class using the Commission approved E8760 energy allocator shown in Table 6 above.

c. Production O&M Expense

When allocating Other Production O&M expenses, the Company used the Commission ordered "Location" method. This method starts by identifying those production O&M expenses that vary directly with energy output. Using this criteria, the only expenses that vary directly with output are expenses for chemicals and water use. These costs are allocated to class using the E8760 allocator shown in Table 6. The remaining O&M costs are split into capacity and energy-related components based on the type of production plant associated with the costs. The stratification percentages shown in Table 5 were used to separate costs. Energy-related costs are allocated to class using the E8760 allocator, while capacity-related costs are allocated using the D10S allocator.

2. *Calculation of Class Rate Impacts of the Updated 2015 Plan*

After all costs had been allocated and revenue requirements by class were calculated, we then determined the estimated bill impacts by class relative to the current rate level. To do this, we calculated the current rate level using the compliance ordered revenues by class with riders included from Docket E002/GR-13-868. We used this calculation to estimate monthly billing units by customer class and resulting typical bills. The CCOSS allocation based estimates of relative percent class increases for the period were then applied to current typical bills to estimate the average dollar per month increase by customer class (see Table 8 below).

Using the above methodology, the incremental costs in the last year of the period (2020) for the Preferred Plan would be expected to increase the average Residential rate by about 4.5 percent on a compounded annual basis through 2020. That is equivalent to a total increase of $20.48 per month above the current rate level.

The impact to the average Large Demand Billed rate would be an increase of about 3.0 percent on a compounded annual basis through 2020, which is equivalent to an increase of 1.37 cents per kWh above the 2015 level.

Table 8: Updated 2015 Plan Estimated Rate Impacts by Class per Year

Rate Class Impacts \1		2015	2016	2017	2018	2019	2020	Comp'd Incr/Yr
Residential (avg rate, ¢/kWh)		12.654¢	13.934	14.372	14.663	15.285	15.775	N/A
Cumul Increase (¢/kWh)			1.280	1.718	2.009	2.632	3.122	N/A
Cumulative Increase (%)			10.12%	13.58%	15.88%	20.80%	24.67%	4.51%
$ Impact/Month, @	656 kWh		$8.40	$11.27	$13.18	$17.26	$20.48	N/A
Sm Non-Dmd (avg rate, ¢/kWh)		11.970¢	12.934	13.248	13.402	13.769	14.013	N/A
Cumul Increase (¢/kWh)			0.963	1.277	1.431	1.799	2.042	N/A
Cumulative Increase (%)			8.05%	10.67%	11.96%	15.03%	17.06%	3.20%
$ Impact/Month, @	952 kWh		$9.17	$12.16	$13.62	$17.12	$19.44	N/A
Demand (avg rate, ¢/kWh)		8.649¢	9.219	9.435	9.559	9.834	10.023	N/A
Cumul Increase (¢/kWh)			0.570	0.786	0.911	1.185	1.374	N/A
Cumulative Increase (%)			6.59%	9.09%	10.53%	13.70%	15.89%	2.99%
$ Impact/Month, @	38,865 kWh		$221.52	$305.49	$354.00	$460.52	$534.16	N/A
Street Ltg (avg rate, ¢/kWh)		15.137¢	17.100	18.340	19.081	19.928	20.810	N/A
Cumul Increase (¢/kWh)			1.964	3.204	3.945	4.791	5.673	N/A
Cumulative Increase (%)			12.97%	21.17%	26.06%	31.65%	37.48%	6.57%
$ Impact/Month, @	60 kWh		$1.18	$1.92	$2.37	$2.87	$3.40	N/A
1/ Average 2015 Rates are Based on the Outcome of Docket No. E002/Gr-13-868.								

3. *Calculation of Class Rate Impacts with the Current Preferred Plan*

Table 9 below shows the estimated bill impacts by class relative to the current rate level for the Current Preferred. The incremental costs in the last year of the period (2020) for the Current Preferred Plan would be expected to increase the average Residential rate by about 4.7 percent on a compounded annual basis through 2020. That is equivalent to a total increase of $21.39 per month above the current rate level.

The impact to the average Large Demand Billed rate would be an increase of about 3.25 percent on a compounded annual basis through 2020, which is equivalent to an increase of 1.5 cents per kWh above the 2015 level.

Table 9: Current Preferred Plan Estimated Rate Impacts by Class per Year

Rate Class Impacts \1	2015	2016	2017	2018	2019	2020	Comp'd Incr/Yr
Residential (avg rate, ¢/kWh)	12.654¢	13.945	14.384	14.778	15.397	15.914	N/A
Cumul Increase (¢/kWh)		1.292	1.731	2.124	2.744	3.260	N/A
Cumulative Increase (%)		10.21%	13.68%	16.79%	21.68%	25.77%	4.69%
$ Impact/Month, @ 656 kWh		$8.47	$11.35	$13.93	$18.00	$21.39	N/A
Sm Non-Dmd (avg rate, ¢/kWh)	11.970¢	12.945	13.261	13.515	13.879	14.147	N/A
Cumul Increase (¢/kWh)		0.975	1.290	1.545	1.908	2.177	N/A
Cumulative Increase (%)		8.14%	10.78%	12.91%	15.94%	18.18%	3.40%
$ Impact/Month, @ 952 kWh		$9.28	$12.28	$14.71	$18.17	$20.72	N/A
Demand (avg rate, ¢/kWh)	8.649¢	9.228	9.446	9.666	9.937	10.149	N/A
Cumul Increase (¢/kWh)		0.580	0.797	1.018	1.288	1.501	N/A
Cumulative Increase (%)		6.70%	9.22%	11.77%	14.90%	17.35%	3.25%
$ Impact/Month, @ 38,865 kWh		$225.35	$309.77	$395.57	$500.67	$583.22	N/A
Street Ltg (avg rate, ¢/kWh)	15.137¢	17.105	18.345	19.159	20.004	20.890	N/A
Cumul Increase (¢/kWh)		1.968	3.209	4.022	4.867	5.753	N/A
Cumulative Increase (%)		13.00%	21.20%	26.57%	32.16%	38.01%	6.65%
$ Impact/Month, @ 60 kWh		$1.18	$1.93	$2.41	$2.92	$3.45	N/A

Attachment F
Demand Response, Grid Efficiency, and Distributed Energy Resources as Alternative Resources

The Commission's January 6, 2016 Order required an analysis of the potential for demand response (DR), improved system or grid efficiencies, and distributed energy resources (DER) to replace all or part of the energy and capacity that would otherwise be provided by new gas-fired resources. Below we provide our view of the future viability of DR and DER, including supply-side, demand-side and grid efficiencies as replacement for large generators.

We have also included a Strategist simulation where all possible alternatives, including incremental demand response, distributed generation, grid modernization, utility scale renewables, and thermal units are simultaneously considered and optimized. In various Stakeholder sessions, the Company has referred to such a process as a "Grand Optimization."

As discussed in greater detail below, conducting an analysis that considers all possible alternatives is difficult given the solution option capacity constraints of the Strategist software and current desktop computer processing capabilities. However, the Company has attempted to conduct such an exercise to the greatest extent possible reflecting the above limitations. Ultimately, our Strategist modelling found that the Company's Current Preferred Plan provides a balanced approach that allows us to add significant amounts of renewable resources while also considering impacts on customer costs, procurement, construction and operations.

A. DER as Replacement of Central Station Generation

We believe there are three fundamental and sequential questions related to technological viability, economics and policy that must be addressed in order to assess whether DERs are a viable replacement for central station generation in the planning horizon considered in this resource plan.

1) **Technological Viability** - Do technologies currently exist to meet the required reliability, safety and operational standards at the scale necessary to effectively replace large central station generation?
2) **Economics** - If replacement is technologically viable, how does the cost of DER options compare to the alternatives over the near and long-term?

3) **Policy** - Are there policy reasons that support expansion of distributed resources as an alternative to new central station generation?

We address each of these questions below.

1) **Do technologies currently exist to meet the required reliability and operational standards at the scale necessary to effectively replace large central station generation?**

As we consider the retirement of Sherco Units 1 and 2, it is important to understand the services and functions that will need to be replaced, particularly those beyond energy and capacity. As noted in our March 16, 2015 Supplement, the Units' size, location and operating characteristics make them unique in the NSPM system and provide important services related to system stability, grid support, and black start capabilities. This is in addition to the replacement capacity and energy required to reliably meet system demand. For context, Sherco Units 1 and 2 are approximately 750 MW each for a combined 1,500 MW of generation.

Given the role of Sherco Units 1 and 2 in the system, a comparable replacement portfolio of distributed resources must be able to:

- Supply the necessary long-term capacity and energy when and where it is needed, in accordance with established safety, security and reliability standards;
- Balance generation with changing load conditions and fluctuations to maintain proper voltage and frequency for the region; and
- Stabilize the grid in the event of a wide-area outage.

Other technical issues and system requirements may emerge upon further study. For example, as discussed in our response to Clean Energy Organizations' Information Request No. 29, advanced inverters may provide some benefits for managing high penetrations of renewable resources, but inverter-connected resources at high levels of penetration generally do not provide the fault current necessary for utility protective relays to operate. As noted in our March Supplement, we have contracted with an independent third party to study the technical impacts of our proposal.

While we recognize the future potential of distributed technologies, it is our understanding that no precedent exists to confidently prove that a distributed portfolio comprised of today's distributed technologies could consistently satisfy all three of these conditions. While it may be possible to design a theoretical portfolio that addresses these requirements, committing to such a plan in practice introduces significant uncertainty and risks, particularly to reliability. Until more operational and performance information is available to better understand what capabilities these technologies do and do not have under a full range of operating conditions and in the context of a large-scale shift away from centralized resources, we recommend continued presence of large-scale, centralized generation in our fleet.

That said, we see the potential for distributed resources to take on a growing role in coming years and are committed to leveraging them as they become technically viable, cost-competitive, and have an established and acceptable operational record. Over time, it is possible that DER technology could advance to the point that distributed resources could become viable alternatives to centralized generation, but such a decision must be based on well-established capabilities, instead of projections.

Below we provide an overview of the likely core components of a hypothetical distributed resource portfolio consisting of DR, DER, and grid efficiencies. As noted above, it is untested and unknown if and to what extent these resources may work together to replace new large-scale, centralized generation.

- *Supply-side Resources* – These resources are necessary to provide the energy and capacity necessary to meet customers' needs.
    - <u>Distributed Generation</u>. Distributed generation would need to be deployed at an unprecedented scale, strategically dispersed and centrally managed to maintain reliable service.
    - <u>Energy Storage</u>. Storage is a critical complement to DG that addresses the intermittency of renewable DG and allows DG to be dispatchable. Battery storage may also provide other system services, such as voltage and frequency regulation, black start capabilities and spinning and non-spinning reserve, though more research is needed to test how those services can be dispatched and "stacked."

- *Demand-side Resources* – These resources have the potential to reduce and/or shift customer demand, thus deferring or avoiding the need for supply-side investments. Demand-side resources, by definition, rely on actions on the customer's side of the meter, which introduces questions of dispatchability and dependability.

  - Demand Response. Existing demand response programs could be expanded to reduce peak demand and reduce the need for additional peaking capacity.
  - Energy Efficiency. Aggressive energy efficiency could lower customer demand and energy, which could reduce the need for generation.
  - Rate Design. With the enabling metering technology, rates could be redesigned to encourage customers to shift energy use more to off-peak, thus reducing the need for additional peaking capacity. Examples include time-of-use rates and demand charges.

- *Grid Efficiencies* – Through technological advances, the grid can be operated to reduce losses and potentially provide capacity benefits.

  - Voltage control. Voltage control, as enabled by an Advanced Distribution Management System (ADMS), Field Area Network (FAN), and other distribution system technologies, can provide energy or capacity benefits. Voltage can be controlled to reduce energy use by maintaining voltage at the lowest acceptable level (often referred to as Distribution Voltage Optimization). An alternative control scheme is to use the system as a stand-by resource or spinning reserve. This is done by maintaining voltage in the typical range (as we do today), and lowering the voltage only when a capacity shortage occurs. Such a reduction can have a significant initial impact, but is expected to taper off over time to a lower plateau. A hybrid scheme may be possible where the system is operated in the conservation mode normally, but if a capacity need is identified, the control reverts to a "Virtual Spinning Reserve" mode.

It is important to acknowledge the pivotal role that grid modernization investments have in enabling DER to play an increased role in the future. For example, communications and control software and technologies such as ADMS, FAN, and Distributed Energy Resources Management System (DERMS), are vital for the control, management and optimization of these resources, making them necessary prerequisites for treating DERs as reliable system resources. For example, the ADMS will enable increased hosting capacity, which is the amount of distributed energy that can be hosted on the distribution system, by allowing, in conjunction with other controls, active mitigation of potentially problematic voltage and load situations.

2) If replacement is technologically viable, how does the cost of DR and DER options compare to the alternatives over the near and long-term?

As discussed above, we believe technology has not sufficiently matured to enable DERs as alternatives to new large-scale generation additions. As is common with technologies still climbing the maturity or commercialization curve, many of the distributed resource technologies that would be needed are not cost-competitive with established technologies. As discussed below, the DER and incremental DR alternatives were not selected in our Grand Optimization due to their higher cost.

However, our existing DR programs continue to be an important part of our resource portfolio, as demonstrated by the increase in our DR forecast. The Company has a long history of success with DR. Currently, we have exceeded 930 MW in the Upper Midwest since we began offering load management programs for customers in the 1980s. While we remain committed to providing customer options, we must continue to be vigilant in adjusting the portfolio in order to be compliant with the rules set by federal regulation and MISO. Further, we must take the opportunity to develop and test customer programs using new technology prior to depending upon them as a resource on our system or in the MISO market.

We have acknowledged that it is likely there will be some attrition over the planning period, wherein customers begin to choose new opportunities with lower demand reduction potential. This may at times be a trade-off between further participation and the ability to self-control, which could reduce our portfolio in the short-term.

Given the modeling result, we have not adjusted our moderate demand response forecast. However, we continue to review new customer choices for DR including dynamic pricing options (time-of-use, peak pricing, etc.), new technologies (smart thermostats), and updated rates to encourage participation. We have also begun investing in a Demand Response Management System to help facilitate new opportunities as they arise due to changing technology.

While the cost declines observed for solar DG and storage over the past few years are encouraging, it is unclear and perhaps unlikely that these cost declines can overcome the economies of scale inherent in larger-scale alternatives. Similarly, while distributed resources may provide other benefits over time, such as deferred or avoided transmission and distribution investments, it is premature to assign a definitive timeline and value to those benefits.

3) Are there policy reasons that support expansion of distributed resources as an alternative to new central station generation?

We recognize the growing interest among our regulators, stakeholders and customers In transitioning to a 21st century electric system and are advancing these interests in several different ways. We agree that it is a worthwhile goal to make plans to move away from coal and other carbon-emitting resources in favor of carbon-free alternatives, as demonstrated by our proposal in this transformational Resource Plan. These proposals are responsive to state energy policy goals, which seek to dramatically lower the state's contribution to climate change, maximize energy efficiency and conservation, and promote renewable energy, among others. The question is in how best to meet those policy goals, while also satisfying the basic requirements of safe, reliable, secure and affordable energy.

With the technological and economic challenges currently facing DERs, we believe we are not yet at the point where DERs can fulfill or have an advantage in satisfying those basic requirements at the scale and speed implicit in this question. We are taking steps to reduce the challenges and prepare for the future grid, such as through our grid modernization efforts and solar plus storage demonstration project proposal, but it is still too early to confidently choose DERs as a reasonable and complete alternative to new central station generation additions.

B. Strategist Analysis

The first step in beginning the optimization was to define the available alternatives to be considered. To narrow the scope of the exercise, the alternatives were reduced to the following representative options:

- *Incremental Demand Response Option* - The DR option was constructed by extrapolating results from the Brattle DR Potential Study[1] to future years. The Brattle study did not contemplate or produce results directly related to this use, and extrapolating the results of the study is inherently an estimate or proxy. To adequately project costs and availability of DR resources many years out would require a new analysis, and could likely produce very different results. Nevertheless, the proxy DR resource was developed as a new optional resource that is incremental to the "Base" DR included in all cases. The incremental capacity and costs were derived by taking the difference between the "High"

[1] Appendix O of our Initial Filing.

and "Base" DR scenarios included in our initial filing. Costs for the new program were then escalated at inflation to determine the costs for an incremental program starting at various years. The incremental DR capacity made available is greater than two new combustion turbines.

- *Incremental Distributed Generation Option* – The alternative reflects current information on distributed small solar projects with representative pricing at $120/MWh with no escalation. Flat pricing assuming technology and project development improvements are expected to offset any inflation.
- *Incremental Grid Modernization* – Costs and operational attributes for grid modernization are not clear enough at this time to develop a reasonable optimization alternative for inclusion in the modeling. We discussed grid modernization qualitatively above.
- *Incremental Renewables* – The same expansion alternatives with vintages and tax benefits that were used in the main scenarios were also included in the Grand Optimization. However, tranches with identical tax benefits were limited to certain specified years to reduce the computational requirements of the model. As an example, 30% ITC solar was limited to be installed in 2021, and full PTC wind was limited to 2018, rather than being available in all years. Late wind with no PTC benefit and late solar with 10% ITC benefit were also offered as options after the expiration of the PTC and ITC benefits.
- *Thermal Alternatives* – The generic thermal CT and CC units were made available in all years. Generic not site specific alternatives were used.

The Grand Optimization tests many resource options for cost-effectiveness including DR, distributed generation, wind generation with and without PTC benefits, and solar generation with 30% or 10% ITC benefits, along with the thermal generation options. Because of the number of resource options available to choose from in each year, the cumulative number of possible combinations is enormous. If there were no limits placed on the Strategist model's logic, the model would need to evaluate every resource option added an arbitrarily large number of times every year to ensure every possible resource combination was evaluated. The size of the problem quickly becomes too large for the software.

Strategist automatically begins to disregard combinations when the problem gets too large, a process called "truncation." Strategist truncates the excess combinations (in the Company's version there are 2,500 combinations retained) based on accumulated cost to the year it needs to truncate. Thus, a plan might get truncated in 2020 if it was not one of the lowest cost 2,500 plans in 2020, even though later in the simulation it might have ultimately ended up being lower-cost had it been allowed to continue in the process. There must be a balance between limiting the number of options per year while ensuring every option has equal chance for its benefits and costs to be included in the final results of the optimization.

There are multiple ways to solve the truncation problem. One way is to prescreen options before putting them into the Strategist model based on relative costs. The Company has done this in evaluating thermal generation technologies. Some thermal generation technologies have been prescreened based on having a cost advantage for similar benefits. An example of a prescreened option is how the Company compared the cost of a 2x1 combined cycle versus a 1x1 combined cycle (CC). The Company determined that over a typical range of capacity factors, the installed cost of a 2x1 CC on a $/kW basis is significantly more favorable than the cost of a 1x1 CC, while providing very similar energy benefits. By prescreening and removing the 1x1 CC option from Strategist, the scale of the problem is reduced.

The Company has not prescreened DR, DG, wind, or solar resource options in the Grand Optimization as these options and the timing of their additions is the main focus of the analysis.

Solving an optimization of this size also requires a "trial and error" iterative approach. Initially, the model is allowed to select any type of resource, but only in smaller quantities. As iterative results indicate what types of technologies are consistently selected at particular times, a small number of these consistently-selected alternatives can be switched from being part of the optimization to being locked in. When the model no longer has to consider them as alternatives, it reduces the problem size. In the next run, the model is allowed to consider additional alternatives beyond those locked in to the plan. If more are taken, then those additional resources are also locked in. By iteratively offering and then locking in resources, a stable point can be determined when the model has just as much of a particular resource as it desires; that is, no additional resources are selected even when available. This iterative approach is essentially the same process that the Company has followed in determining its proposals in March and October 2015.

The Grand Optimization was analyzed in two steps. The first step is a <u>capacity-need</u> only optimization, with the second step including the system energy benefits of non-capacity (or "superfluous") resources in a <u>resource-need</u> optimization. Both steps find the lowest PVSC based on the assumptions and meet the required reserve margin; however, a capacity-need optimization allows the Strategist Model to add resource options only if there is a capacity need to meet the required reserve margin. By contrast, a resource-need optimization allows the Strategist Model to add resource options even if there is not a capacity need to meet the required reserve margin. An example to explain the distinction between the two optimizations is to consider a wind resource option with production tax credit benefits - the wind alternative contributes relatively little to firm capacity, and a very large amount of wind would be required to offset the need for even one CT. However, the low-cost energy could very well be below the marginal system energy costs, resulting in significant economic value if added as a resource. The wind would most likely not be selected in a capacity-need optimization, but could very likely be selected in the resource-need optimization.

1. *Capacity-Need Optimization Process and Results*

The Company started the capacity-need optimization from the results of the Company's Current Preferred Plan. In this Plan, which adds 1,800 MW of wind and 1,000 MW of solar and retires Sherco Units 1 and 2 in 2026 and 2023 respectively, there is one combined cycle unit added and nine combustion turbine units added from 2018 to 2030. An optimized capacity-view with wind, solar, DR, and DG options should add a similar amount of firm capacity. An iterative process as described above was followed, and the PVSC from each iteration was compared to the prior iteration to ensure that the optimization was getting more efficient. The least-cost solution of the capacity-need optimization is displayed below in Table 1. It is important to note that no "real-world" constraints were placed on the number or type of options that could be added in a given year, and no attempt was made to smooth the rate impact of the additions. In actuality, the results of this exercise need to be tempered with considerations of system operational limitations, contracting, negotiating and construction logistics (especially wind equipment transport and limited tall crane availability for turbine erection), large step increases in customer costs, etc. Since there is no capacity need until 2024, after a Sherco unit is retired, all the resource additions are in 2024 or later. The capacity-need optimization adds 800 MW of late wind, 3600 MW of late solar, four CTs, and one CC from 2024 to 2030. The DR and DG alternatives were not selected due to the higher cost of those resources.

Table 1: Capacity-Need Expansion Plan

28_C: Capacity-Need Optimization	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Small Solar	48	42	45	49	53	58	17	20	24	29	34	41	49	59	71	85	723
Large Solar	-	-	287	-	-	-	-	-	-	-	-	800	1,800	800	-	200	3,887
Wind	350	200	200	-	-	-	-	-	-	-	-	-	400	400	-	-	1,550
PPA CT	-	-	-	-	-	-	-	-	-	230	460	230	-	-	-	-	920
PPA CC	-	-	-	-	345	-	-	-	-	-	778	-	-	-	-	-	1,123
Fargo CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2. *Resource-Need Optimization*

The number of possible combinations in the resource-need optimization is much greater than the possible combinations in the capacity-need optimization. The resource-need optimization considers increments of wind, solar, and DR options above the number required to meet the reserve margin and internally adds them to the system to evaluate cost effectiveness. Since Strategist quickly exceeds its maximum number of combinations with these incremental superfluous resources, the Company had to extensively use an iterative process.

As we discussed earlier, the iterative process uses the results of a prior incremental test to determine if in the next run a resource should be locked in place or removed. The Company took the PVSC results of each run to verify that the solution to the optimization was becoming more efficient with each iteration.

The resource-need optimization used the results of the capacity-need optimization as well as the Company's Current Preferred Plan to help set the initial constraints. As an example, since the PTC wind and 30% ITC solar are similar or lower cost than corresponding non-PTC late wind and 10% ITC late solar additions of the capacity-need optimization, the resource-need optimization would be expected to add no less renewable energy than the capacity-need optimization.

Using run results and the iterative process, the least-cost plan consisted of PTC wind, combustion turbines, and late solar as the best options. The least-cost solution of the resource-need optimization is displayed below in Table 2. The resource-need optimization adds 5,200 MW of PTC wind, 2,600 MW of late solar, and seven combustion turbines. Again, the DR and DG alternatives were not selected due to the higher cost of those resources. As with the capacity-need results, no "real-world" constraints were set on the options by year and the same considerations would apply to convert theoretical results such as this into an actual plan.

Table 2: Resource-Need Expansion Plan

28_B: Resource-Need Optimization	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Small Solar	48	42	45	49	53	58	17	20	24	29	34	41	49	59	71	85	723
Large Solar	-	-	287	-	-	-	-	-	-	-	-	-	1,400	1,000	-	200	2,887
Wind	350	200	200	-	5,200	-	-	-	-	-	-	-	-	-	-	-	5,950
PPA CT	-	-	-	-	-	-	-	-	-	-	690	690	230	-	-	-	1,610
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	345
Fargo CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

In summary, the capacity-need and resource-need optimizations indicate that the Company's Current Preferred Plan is consistent and prudent. Applying a more rateable approach to renewables, while still incorporating large amounts of PTC-eligible wind and tax incented solar makes sense for customers. Our Current Preferred Plan represents a balance of the Resource-Need and Capacity-Need Expansion Plans. Adding 5,200 MW of wind in 2018 based on the results of the Resource-Need Optimization is not a viable option from a rate-impact, contracting, construction or operations perspective. Likewise, waiting until 2026 to add additional renewables based on the Capacity-Need Optimization fails to account for the energy and environmental benefits of adding competitive fixed price renewable energy resources to our system in the near-term. Our plan balances the advantages of adding significant amount of renewables–1,200 MW by 2020–but in a manner that also considers the impacts on customer costs.

Attachment G
Socioeconomic Study Summary

The Company has worked with the Leeds School of Business at the University of Colorado Boulder and the Labovitz School of Business and Economics at the University of Minnesota Duluth to prepare an analysis of the economic impacts on the state of Minnesota, including Sherburne County, of alternative retirement and replacement scenarios for the Sherburne County generating Units 1 and 2 (Sherco). This study was initiated in response to the Commission's request in our Sherco Life Cycle Management (LCM) proceeding.[1] This study – Economic Impacts of Sherco Plant Alternatives – is included with this filing as Attachment F1 and looked at impacts on employment, gross domestic product (GDP), and disposable personal income on those locations impacted by a change in operating expenditures, capital expenditures, and electricity rates. The scenarios, explained in more detail below, included various Sherco unit retirement dates and the replacement of the two Sherco units with one combined cycle (CC) at the Sherco site and one CC located in Dakota County.

While this study did not model a scenario that directly reflects our Current Preferred Plan (ceasing coal generation at Sherco Unit 1 in 2026 and Sherco Unit 2 in 2023), those dates do fall within the range of scenarios analyzed, with retirement dates ranging from Sherco 1 and 2 in 2020 to Sherco 1 in 2031 and Sherco 2 in 2025. Retirement of either of the Sherco units generates initial positive economic impacts in Sherburne County as a result of decommissioning activities and the construction of a combined cycle at the Sherco site and is then followed by negative economic impacts. The pattern of positive impacts followed by negative impacts is due to shifting the retirement to a date earlier than the economic end of life. The long-term economic effect on Sherburne County after this initial activity is negative under most scenarios due to lost operating and maintenance activity. The construction of replacement generation for one Sherco unit retirement, sited in Dakota County in the scenarios examined for this study, generates positive economic impacts in Dakota County during the construction phase and the succeeding years as a result of ongoing operations. The effect of Sherco unit retirements is a shift in employment from Sherburne County to Dakota County, or the location in which replacement generation is constructed. The timing of those impacts varies in relation to the timing of

[1] *In the Matter of Xcel Energy's Sherco Life Cycle Management Study/2014 Integrated Resource Plan*, Docket No. E002/RP-13-868.

generator retirement and replacement. Construction of replacement generation within Minnesota helps to offset some of the negative economic impacts in the State of Minnesota associated with lost generation.

A. Methodology

The research analysis method used for this study was the Regional Economic Models, Incorporated's (REMI) input-output, general equilibrium, econometric, and economic geography model, using state and national economic and demographic data, as well as data from the Company including capital expenditures, operating expenditures, and revenue requirements for each scenario. The study covered a period from 2015 through 2040, looking at near-term, mid-term, and long-term impacts of alternative retirement and replacement scenarios for Sherco Units 1 and 2. This study period was selected in order to capture the economic activity in the near-term related to decommissioning and the construction of replacement generation, as well as the longer-term impacts of operations and employment at the replacement facilities.

While the specific location of replacement generation for the Sherco units is unknown, Dakota County was selected because it is within Minnesota and the study's purpose was to examine impacts on the State of Minnesota. In addition, it allows for the transfer of economic impacts, such as jobs from Sherco to another location, to be quantified. Therefore, economic impacts were analyzed in this report for Sherburne County, Dakota County, and the rest of Minnesota.

The study examined four scenarios and a baseline scenario, detailed in Table 1 below. We include for comparison the Current Preferred Plan scenario, to illustrate the similarity of the retirement dates and replacement plans between our plan and the scenarios studied. These scenarios correspond to the Updated 2015 Plan and alternative retirement scenarios that were presented in the March 16, 2015 Supplement. The results of the retirement scenarios included in the study are reported as the change in economic impacts relative to the baseline scenario. Replacement generation options included in the study were modeled based on combinations of comparatively-sized gas-fired CC generators, located at the site of our Black Dog plant in Dakota County and at the existing Sherco site.

Table 1: Scenarios Analyzed in the Socioeconomic Study

Scenario	Unit 1 Retirement Date	Unit 2 Retirement Date	Unit 1 Replacement	Unit 2 Replacement
Baseline/ Updated 2015 Plan	2031	2031	Combined Cycle at Sherco	Combined Cycle at Black Dog
SHC1 2031 SHC2 2025	2031	2025	Combined Cycle at Sherco	Combined Cycle at Black Dog
SHC1 2025 SHC2 2025	2025	2025	Combined Cycle at Sherco	Combined Cycle at Black Dog
SHC1 2020 SHC2 2020	2020	2020	Combined Cycle at Sherco	Combined Cycle at Black Dog
SHC1 2023 SHC2 2020	2023	2020	Combined Cycle at Sherco	Combined Cycle at Black Dog
Current Preferred Plan*	2026	2023	Combined Cycle at Sherco	Combustion Turbine in Fargo

**Not analyzed in this study, but included for comparison.*

B. Results

Overall, the study found that all early retirement scenarios, when compared to the Baseline, result in comparatively slower growth within the Minnesota economy. This impact, however, represents a relatively small percentage of the overall Minnesota economy, as the state's total Gross Domestic Product (GDP) for 2014 was $316 billion. The impact on statewide GDP, shown in Table 2 below, was between $16 million and $90 million, representing a less than one percent impact. None of the scenarios reviewed has a recessionary impact on the state.

Table 2: Sherco Retirement Impacts on the Minnesota Economy, 2015-2040 Averages

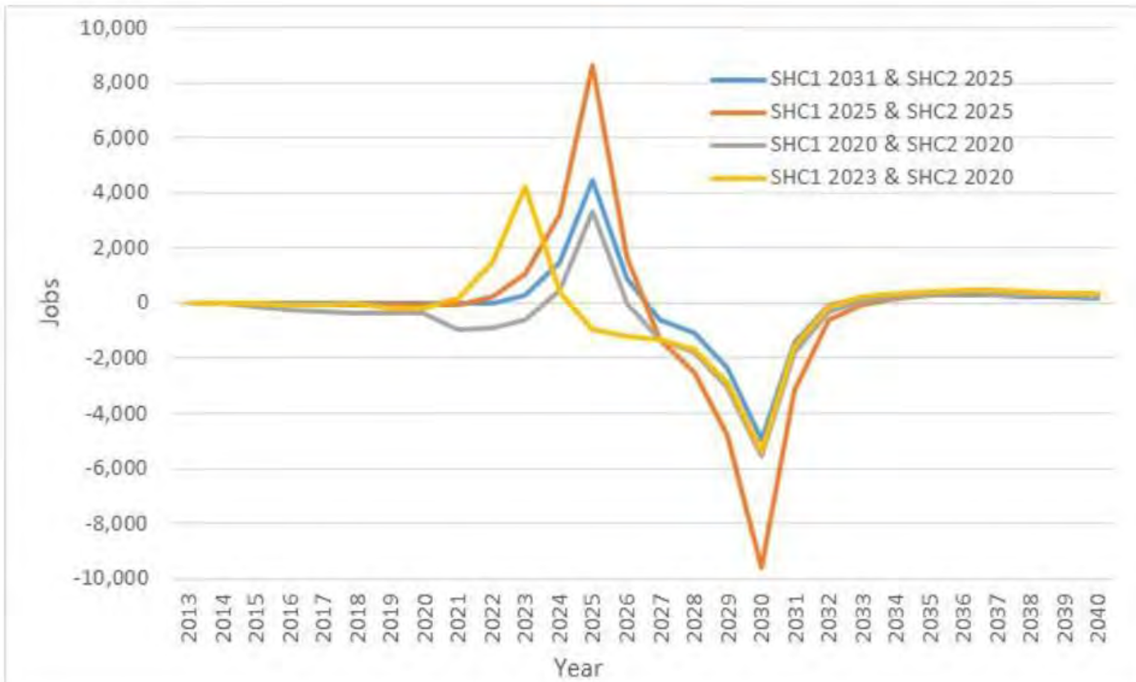
Metric	Units	2015–2040			
		SHC1 2031/ SHC2 2025	SHC1 2025/ SHC2 2025	SHC1 2020/ SHC2 2020	SHC1 2023/ SHC2 2020
Total Employment	Jobs	-75	-258	-570	-300
	Percent Change	*0.00%*	*-0.01%*	*-0.01%*	*-0.01%*
Gross Domestic Product	Dollars (Thousands)[1]	-16,021	-53,257	-89,966	-49,813
	Percent Change	*0.00%*	*-0.01%*	*-0.02%*	*-0.01%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-13,719	-47,919	-83,485	-52,443
	Percent Change	*0.00%*	*-0.01%*	*-0.03%*	*-0.02%*

[1] Fixed (2014) dollars.

All scenarios will result in increased revenue requirements associated with the capital cost of replacement generation. The increase in revenue requirements will result in increased electricity rates for residential, commercial, and industrial utility customers, which will in turn have a negative economic impact on the state overall. The extent of the economic impacts is affected by factors that include the retirement cost of existing units, the source of inputs for capital investments, the ongoing operating costs, the sources of fuels, and the revenue requirements assigned to the customer base.

The study showed the impacts of the various retirement scenarios on private employment, shown in Figure 1 below, as compared to the baseline. This illustrates how the timing of the impacts on employment shifts relative to the retirement dates. In each scenario, there is a near-term increase in employment relative to the baseline due to decommissioning and the construction of replacement generation. The subsequent dip in employment below the baseline is due to the retirement of the Sherco units.

Figure 1: Sherco Retirement Impact on Minnesota Private Employment



C. Summary

While the Socioeconomic Study did not model a scenario that directly reflects our Current Preferred Plan, our proposed 2023 and 2026 retirement dates fall within the range of scenarios analyzed. Results show that all early retirement scenarios, when compared to a baseline, result in moderately slower growth in the Minnesota economy. The closure of Units 1 and 2 showed negative impacts on employment, GDP, and disposable personal income in Sherburne County. However, construction of replacement generation within Minnesota creates positive impacts where the replacement is constructed and helps to offset some of the negative economic impacts in the state associated with early retirement. The path charted by our Current Preferred Plan provides certainty for stakeholders, as well as an 8 to 10 year transition period. With our proposal for on-site replacement generation, we demonstrate our commitment to promoting economic development in Central Minnesota.

NORTHERN STATES POWER

ECONOMIC IMPACTS OF SHERCO PLANT ALTERNATIVES

Research by:

Business Research Division
Leeds School of Business
University of Colorado Boulder

Reviewed by:

Bureau of Business and Economic Research
Labovitz School of Business and Economics
University of Minnesota Duluth

October 15, 2015

A report prepared for Northern States Power.

Leeds School of Business
UNIVERSITY OF COLORADO BOULDER
BUSINESS RESEARCH DIVISION

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DEFINITIONS

Employment: Includes the number of full-time and part-time jobs (headcount) by business physical location.

Deflators: Measure of price changes within an industry.

Gross Domestic Product: Total value of final goods and services produced each year within a country or region.

Leakage: Economic activity that occurs outside the area of study but is driven by activity within the study area.

Metropolitan Statistical Area: Geographic areas with 50,000 or more population.[1]

Multiplier: Change in total economic activity driven by a change in direct economic activity.

Output: Total production value of goods and services, including intermediate goods purchased and value added.

Personal Income: Includes all sources of income, including employee compensation, proprietors' income, rental income, capital income, and transfer payments.

[1]For more information, visit: http://www.whitehouse.gov/sites/default/files/omb/assets/fedreg_2010/06282010_metro_standards-Complete.pdf, retrieved July 13, 2014.

EXECUTIVE SUMMARY

This document presents the results of an analysis prepared by the Leeds School of Business to quantify the economic impacts on the state of Minnesota of alternative retirement dates for the Northern States Power Company (NSP) coal-fired Sherco 1 and Sherco 2 generating units. The purpose of an economic impact study is to identify the impacts on employment, gross domestic product, disposable personal income, and other economic metrics for those locations impacted by a change in operating expenditures, capital expenditures, property taxes, and electricity rates.

The study area was the state of Minnesota. Impacts on Sherburne County and Dakota County are reported separately from all other counties in the state. Sherburne County is reported separately because the Sherco generating units are both located there, and this separation allows the local effect of an early Sherco retirement to be identified. Dakota County is reported separately because it may be a viable location for the construction of the generation needed to replace the retired Sherco generation. While the location of replacement generation is currently unknown, the purpose of the study was to examine impacts on the state of Minnesota. Therefore, it was important to select a location for replacement generation within the state in order to maintain the focus on Minnesota economic impacts.

The study period was the years 2015 through 2040. This period was selected to capture the near-term economic activity related to decommissioning Sherco and constructing replacement generation, as well as the effects of a change in electricity rates. An abbreviated description of the four retirement scenarios is provided below. A detailed description of the scenarios is provided in the Scenarios section of the report.

The study examined four retirement scenarios and a baseline scenario. The baseline scenario included operating Sherco 1 and Sherco 2 through 2031, then replacing them with the combined cycle generators. Four retirement scenarios were included, and the study results are reported as the change in economic impacts of these scenarios relative to the baseline scenario. The replacement generation that was modeled was based on combinations of comparatively sized gas-fired combined cycle generators located at the Black Dog site in Dakota County and at the Sherco site.

- SHC1 2031 & SHC2 2025: Sherco 1 and Sherco 2 will stop operation in 2031 and 2025, respectively. Sherco 2 will be replaced with a combined cycle generator constructed at Black Dog, and Sherco 1 will be replaced with a combined cycle generator constructed at the Sherco site.
- SHC1 2025 & SHC2 2025: Sherco units 1 and 2 will stop operation in 2025 and be replaced with combined cycle generators constructed at the Sherco site and the Black Dog site.
- SHC1 2020 & SHC2 2020: Sherco units 1 and 2 will retire in 2020 and be replaced with combined cycle generators constructed at the Sherco site and the Black Dog site.
- SHC1 2023 & SHC2 2020: Sherco 2 will retire in 2020 and be replaced with a combined cycle generator constructed at the Black Dog site. Sherco 1 will retire in 2023 and be replaced with a combined cycle generator constructed at the Sherco site.

The research team used the REMI model for the analysis. The model used by Leeds was provided by REMI specifically for the state of Minnesota using national and Minnesota economic and demographic data. The REMI model used for this analysis is the three region, PI+ model 1.6.8 for Sherburne County, Dakota County, and the rest of Minnesota. The 1.6.8 model includes historical data through 2012. NSP provided data that included capital expenditures, operating expenditures, revenue requirements, and taxes for each scenario. The research team worked under the assumption that the company provided good-faith estimates for each scenario.

The study findings show that the continued operation of and investments in Sherco units 1 and 2 through 2031, followed by replacement with combined cycle generators, will have the greatest ongoing positive economic contribution to the Minnesota economy. The retirement and replacement scenarios have varying degrees of impact on the Sherburne County and Dakota County economies. Retiring either of the Sherco units generates positive economic activity in Sherburne County during the decommissioning phase, but produce a negative economic cost during the succeeding years under most scenarios due to lost operating and maintenance activity. The construction of replacement generation in Dakota County generates positive economic activity during the construction phase and during the succeeding years given the change in local operations. There will be an increase in revenue requirements for all retirement scenarios due to the capital-related costs of replacement generation. These higher costs will increase electricity rates for residential, commercial, and industrial utility customers and will have a negative economic impact on Sherburne County, Dakota County, and the rest of Minnesota. The extent of the economic impacts is affected by factors that include the retirement costs of existing units, the sources of inputs for capital investments, the ongoing operating costs, the sources of fuels, and the revenue requirements assigned to the customer base.

Comparing the four alternative scenarios to the baseline scenario, the time series of economic impacts on Minnesota GDP is illustrated in Figure 1. The figure shows the near-term benefits accrued during the decommissioning and construction phase, followed by a negative impact due to higher revenue requirements over the remainder of the study period. The smallest negative economic impact results from the retirement and replacement of generators in 2025 and 2031. The greatest negative economic impact relative to the baseline results from the earlier retirement of both Sherco 1 and Sherco 2 in 2020 and the replacement in 2026 and 2031.

The lack of indigenous fossil resources in Minnesota limits potential gains in fuel switching. Since Minnesota does not have indigenous coal or natural gas resources, it necessitates importing fuel from other states and requiring gas pipeline upgrades. The baseline scenario and each early retirement scenario require additional investments in gas pipelines and transmission totaling about 10% of total capital expenditures.

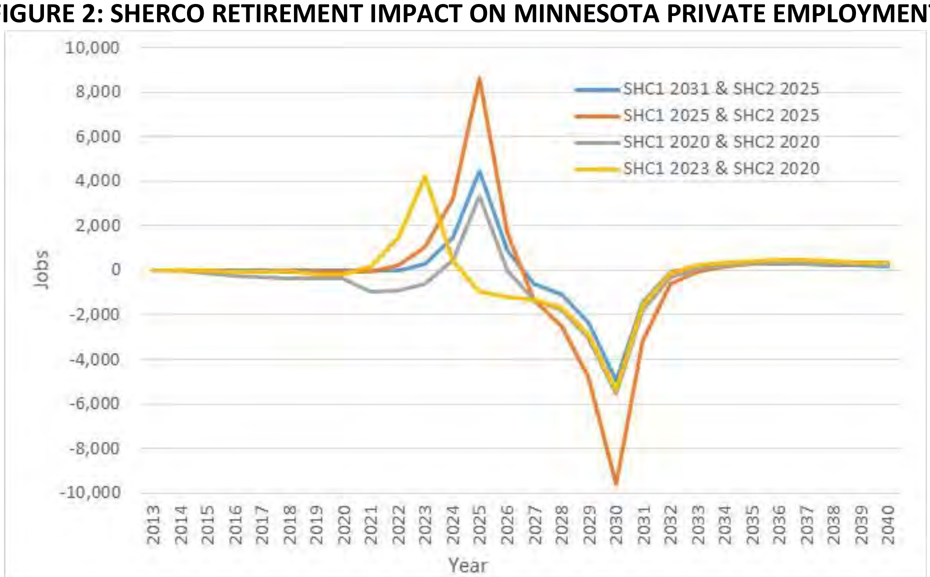
Since all scenarios involve generator retirement and replacement, the spikes and dips in economic activity are largely due to timing—specifically the timing of activity compared to the baseline scenario. Retiring units in 2020 instead of 2031, for instance, increases economic activity in the 2020s, but decreases economic activity in the 2030s. Since all of the alternative scenarios retire and replace Sherco

1 and Sherco 2 sooner than the baseline scenario, then all of the alternative scenarios also shift economic activity earlier.

FIGURE 1: SHERCO RETIREMENT IMPACT ON MINNESOTA GDP

A similar pattern is shown for Minnesota private employment, which is shown in Figure 2. Likewise, the near-term activity related to the decommissioning of existing generation and the constructing of replacement generation increases jobs. While employment continues to increase in Minnesota under all scenarios over the study period, early retirement of the Sherco generators results in a decrease in Minnesota employment compared to the baseline scenario.

FIGURE 2: SHERCO RETIREMENT IMPACT ON MINNESOTA PRIVATE EMPLOYMENT



In addition to the differences between near-term and long-term effects shown above, there are also location specific impacts for Sherburne County, Dakota County, and the rest of Minnesota. Compared to the baseline scenario, most retirement scenarios show negative impacts on Sherburne County given that this location will experience decreasing generation operations over time. Dakota County benefits from early retirement of the first Sherco generator because the construction and new operating activity at the Black Dog site will be a boost to the county economy, effectively outweighing the economic costs associated with higher revenue requirements. However, while the near-term benefits of constructing the replacement generation in Dakota County may be large, these employment benefits decline rapidly and are not large over the entire study period. Locally, the impact of early retirement is a shift in employment from Sherburne County to Dakota County; statewide, employment continues to grow but at a slower rate.

A summary of all economic metrics for each retirement scenario is shown in Table 1 for the state of Minnesota. Each of the retirement and replacement scenarios place Minnesota on a slightly slower economic growth trajectory between 2015 and 2040, though the change in growth is relatively small. From 2015 to 2040, under the various scenarios, total statewide employment is lower, on average, by 75 jobs to 570 jobs as compared to the baseline; GDP is lower by $16 million to $90 million, and real disposable personal income is lower by $14 million to $83 million. In percentage terms, the change from the baseline scenario is less than one-tenth of 1%.

While the economic impacts of the retirement and replacement scenarios may appear large in absolute values, the percentage change of the impacts is relatively small in light of the magnitude of the overall Minnesota economy. Accordingly, the impacts are not recessionary—the economy continues on a trajectory of growth, albeit slightly slower growth.

TABLE 1: SHERCO RETIREMENT IMPACTS ON THE MINNESOTA ECONOMY, AVERAGE 2015–2040

		Average 2015–2040			
Metric	**Units**	**SHC1 2031/ SHC2 2025**	**SHC1 2025/ SHC2 2025**	**SHC1 2020/ SHC2 2020**	**SHC1 2023/ SHC2 2020**
Total Employment	Jobs	-75	-258	-570	-300
	Percent Change	*0.00%*	*-0.01%*	*-0.01%*	*-0.01%*
Gross Domestic Product	Dollars (Thousands)[1]	-16,021	-53,257	-89,966	-49,813
	Percent Change	*0.00%*	*-0.01%*	*-0.02%*	*-0.01%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-13,719	-47,919	-83,485	-52,443
	Percent Change	*0.00%*	*-0.01%*	*-0.03%*	*-0.02%*

[1]Dollars are fixed (2014) dollars.

A summary of all economic metrics for each retirement scenario is shown in Table 2 for Sherburne County. Most of the retirement and replacement scenarios place Sherburne County on a slightly slower economic growth trajectory between 2015 and 2040, though the change in growth is relatively small. From 2015 to 2040, under the various scenarios, the changes in total statewide employment ranges between 5 and -140 jobs as compared to the baseline; the changes in GDP range between -$4 million and -$19 million, and the changes in real disposable personal income range between -$2 million and -$11 million. In percentage terms, the change from the baseline scenario is less than 1%.

TABLE 2: SHERCO RETIREMENT IMPACTS ON SHERBURNE COUNTY, AVERAGE 2015–2040

		Average 2015–2040			
Metric	**Units**	**SHC1 2031/ SHC2 2025**	**SHC1 2025/ SHC2 2025**	**SHC1 2020/ SHC2 2020**	**SHC1 2023/ SHC2 2020**
Total Employment	Jobs	-31	-22	-140	5
	Percent Change	*-0.07%*	*-0.05%*	*-0.34%*	*0.01%*
Gross Domestic Product	Dollars (Thousands)[1]	-4,097	-6,863	-18,871	13,737
	Percent Change	*-0.11%*	*-0.18%*	*-0.48%*	*0.35%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,406	-2,920	-10,584	2,668
	Percent Change	*-0.05%*	*-0.06%*	*-0.22%*	*0.06%*

[1]Dollars are fixed (2014) dollars.

A summary of all economic metrics for each retirement scenario is shown in Table 3 for Dakota County. Most of the retirement and replacement scenarios place Dakota County on a slightly faster economic growth trajectory between 2015 and 2040, though the change in growth is relatively small. From 2015 to 2040, under the various scenarios, the changes in total statewide employment ranges between 18 and -12 jobs as compared to the baseline; the changes in GDP range between -$445,000 and -$6 million, and the changes in real disposable personal income range between -$714,000 and -$7 million. In percentage terms, the change from the baseline scenario is less than 1%.

TABLE 3: SHERCO RETIREMENT IMPACTS ON DAKOTA COUNTY, AVERAGE 2015–2040

		Average 2015–2040			
Metric	**Units**	**SHC1 2031/ SHC2 2025**	**SHC1 2025/ SHC2 2025**	**SHC1 2020/ SHC2 2020**	**SHC1 2023/ SHC2 2020**
Total Employment	Jobs	18	0	-12	7
	Percent Change	*0.01%*	*0.00%*	*0.00%*	*0.00%*
Gross Domestic Product	Dollars (Thousands)[1]	-445	-3,757	-5,751	-3,430
	Percent Change	*0.00%*	*-0.01%*	*-0.02%*	*-0.01%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-714	-4,508	-6,641	-5,182
	Percent Change	*0.00%*	*-0.02%*	*-0.02%*	*-0.02%*

[1]Dollars are fixed (2014) dollars.

STUDY METHODOLOGY

The Business Research Division at the University of Colorado Boulder was hired by Northern States Power to conduct economic impact analyses on retirement scenarios for the Sherco generating units in Sherburne County, Minnesota. This analysis examines the economic impacts of various early retirements of Sherco 1 and Sherco 2. Economic impact studies detail the direct spending that a company or activity has on the area of study, as well as the indirect impact, which is the ripple effect that direct spending has on other businesses in the community. This term is also referred to as the *multiplier effect*, wherein companies utilize the local supply chain. A multiplier is a numeric way of describing the full effects of money changing hands within an economy. For instance, when NSP purchases natural gas, this affects the mining and transportation industries. This is the indirect impact. Additionally, spending by employees has an inherent effect on local communities as they purchase groceries, clothes, and gas; pay rent or a mortgage; get haircuts, etc. This is understood as the induced impact.

The research team used the REMI model for the analysis. Appendix 1 provides an overview of the REMI model. The REMI model is a dynamic forecasting and policy analysis model that incorporates econometric, input-output, and computable general equilibrium techniques. The model was created by REMI specifically for the state of Minnesota using national and Minnesota economic and demographic data. The REMI model used for this analysis is the three region, PI+ model 1.6.8 for Sherburne County, Dakota County, and the rest of Minnesota, with 2012 data as the last historical year within the model.

NSP defined the scenarios to be examined in this study. These are described in detail in the Scenarios section. A baseline scenario was provided by NSP which included operating Sherco units 1 and 2 through 2031, followed by replacement with combined cycle generators. The research team developed economic scenarios that included spending and rate changes brought about by four different Sherco retirement and replacement scenarios. The result is a simulated forecast of the economy under scenarios where utility rates and spending on operating and capital expenditures change. Last, the report compares the simulations to the baseline scenario to quantify the economic impacts on the Minnesota economy and on Sherburne County and Dakota County.

The research team collected data on NSP estimates related to ongoing operating and maintenance expenditures, capital expenditures, and revenue requirements. The timing of operating and capital expenditures is specific to each scenario. The research team worked under the assumption that the company provided good-faith estimates for each scenario.

Data were provided in nominal dollars, quantified in the year of expected impact. The impacts are presented in fixed, 2014 dollars, and discounted by the model using industry price deflators.

Costs were entered into the REMI model based on total activity expenditures. The researchers deferred to the model for the local purchasing coefficients for each economic region modeled, which included Sherburne County, Dakota County and the rest of Minnesota. This reduces subjectivity and error associated with asking NSP the source and composition of labor, capital, and intermediate inputs to production by community. The local purchasing coefficients within REMI change over time based on changing demand.

ECONOMIC MODEL AND THE MINNESOTA ECONOMY

The REMI model used for this analysis is the three region, PI+ model 1.6.8 for Sherburne County, Dakota County, and the rest of Minnesota. The model used for this study excludes the government spending response to changes in GDP. The REMI model includes an input-output table, industry spending patterns, and local purchasing coefficients.

When working with statewide models, the research team calibrates demographics using state demography forecasts for age, gender, and race. However, given the detailed economic regions, which included Sherburne County, Dakota County, and rest of Minnesota, no further model calibration was applied given the detailed data available for these economic regions.

Sherburne County and Dakota County are part of the Minneapolis-St. Paul-Bloomington Metropolitan Statistical Area. Data from the Bureau of Labor Statistics' Quarterly Census of Employment and Wages show the area recorded 1.8 million total nonfarm covered employees in 2014; Sherburne County represented 1.4%, or 25,835 of the total, and Dakota County represented 10%, or 180,324 of the total. Data from the Bureau of Economic Analysis shows Minnesota GDP of $316 billion in 2014. Real GDP in the state grew at a rate of 1.4% year-over-year. Per capita personal income for the state in 2014 was $48,711. Per capita personal income in 2013, which is the most current data available, was $50,687 in Dakota County and $36,358 in Sherburne County.

The REMI standard regional control places Sherburne County, Dakota County, and the rest of Minnesota on a growth trajectory throughout the analysis horizon, with faster rates of growth in the short term and slowing growth over the entire study period (Figure 3). Similar to recent years, Sherburne County is projected to grow employment at a faster rate than Dakota County and the rest of the state.

FIGURE 3: EMPLOYMENT FORECAST, 2015–2040

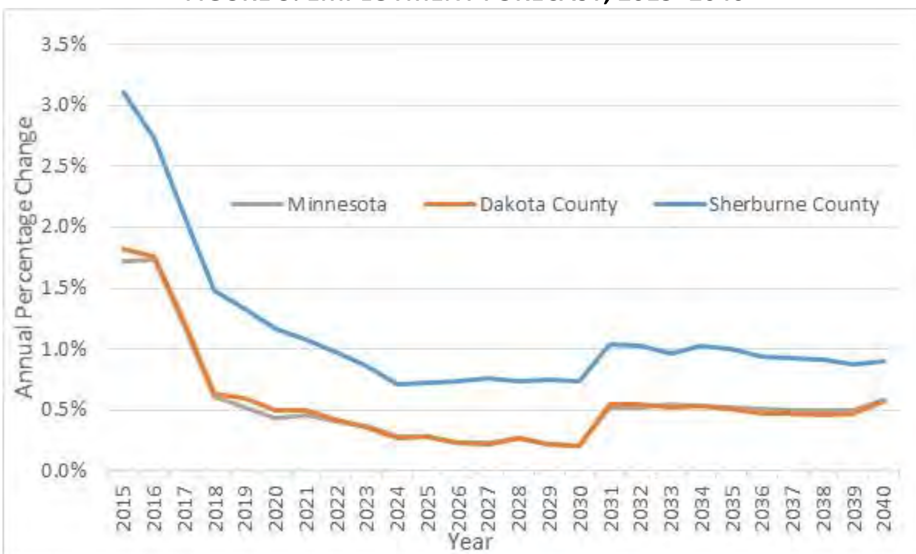
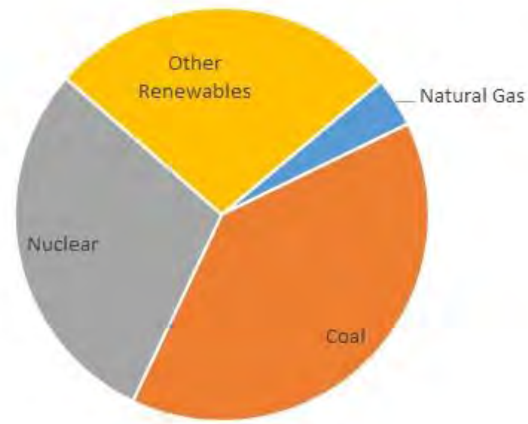


TABLE 4: PROJECTED COMPOUND ANNUAL GROWTH RATES, 2015–2040

COUNTY	EMPLOYMENT	GDP	PERSONAL INCOME
Sherburne County	1.1%	2.4%	3.0%
Dakota County	0.5%	2.1%	2.5%
Rest of Minnesota	0.5%	2.1%	2.3%

As a side point, Minnesota ranked 33rd in the nation in total energy production and 18th for total energy consumed per capita in 2012. As shown in Figure 4, approximately 46% of energy generated in the state came from coal-fired power plants, and an additional 21% was produced by nuclear power plants. Minnesota ranked 7th in wind-generated electricity and is also a top producer of ethanol, with more than 20 corn-based ethanol production plants.

FIGURE 4: MINNESOTA ELECTRICITY GENERATION, GIGAWATT HOURS, 2012



Source: Energy Information Administration.

SCENARIOS

Sherco Generating Units 1 and 2 were built in the 1970s, and a third unit was built in the 1980s. Since installation, these units have been operating for 38, 37, and 27 years, respectively, as of 2014. The 2,400 MW station burns an estimated 30,000 tons of Montana and Wyoming coal daily. In addition to normal operating maintenance, investments have been made to improve the ability of wet scrubbers in Units 1 and 2 to capture sulfur dioxide and ash, as well as in technology to reduce particulates. Modifications and upgrades have been completed to achieve over 90% reduction of sulfur dioxide (SO_2) to meet Best Achievable Retrofit Technology (BART) criteria.

The five scenarios include one baseline scenario where Sherco 1 and Sherco 2 are operated through the Xcel Energy 2016–2030 Upper Midwest Resource Planning period and four retirement scenarios. These scenarios correspond to the Preferred Plan and Preferred Plan Sherco retirement scenarios provided in the March 16, 2015 Supplement. The only change in these scenarios was to replace the first two combined cycle units represented by generic combined cycle units with location specific combined cycle units. This change was required to quantify the economic impacts of Sherco retirements on the local and the state economy.

Baseline

This is the “Preferred Plan” (Resource Plan Scenario 10, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 1 and Sherco 2 continue operation through the end of the Resource Planning period (2030). On-going capital replacement projects continue for both units to maintain reliable operations. The level of investment declines a few years before retirement. These units stop generating January 1, 2031 and remain in standby operating condition until they are retired June 1, 2031. This delay occurs in order to retain accreditation for the Midcontinent Independent System Operator (MISO) capacity year. No Selective Catalytic Reduction (SCR) technology is installed on Sherco 1 and Sherco 2. The replacement combined cycle generators are installed in 2031.

SHC1 2031 & SHC2 2025

This is the "Preferred Plan with Retire 1 Unit 2025" (Resource Plan Scenario 10B, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 2 will stop generating at the end of the year 2025. This unit will remain in standby operating condition until it is retired June 1, 2026. A replacement combined cycle generator will be constructed at the Black Dog site and begin operation upon the Sherco 2 retirement in 2026. No SCR will be added to Sherco 2. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

Sherco 1 will stop generating January 1, 2031, and remain in standby operating condition until it is retired June 1, 2031. No SCR will be added to Sherco 1. A replacement combined cycle generator will be constructed at the Sherco site and begin operation upon the retirement of Sherco 1 in 2031. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

SHC1 2025 & SHC2 2025

This is the "Preferred Plan with Retire 2 Units 2025" (Resource Plan Scenario 10G, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 2 will stop generating at the end of the year 2025. This unit will remain in standby operating condition until it is retired June 1, 2026. A replacement combined cycle generator will be constructed at the Black Dog site and begin operation upon the Sherco 2 retirement in 2026. No SCR will be added to Sherco 2. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

Sherco 1 will stop generating at the end of the year 2025. This unit will remain in standby operating condition until it is retired June 1, 2026. A replacement combined cycle generator will be constructed at the Sherco site and begin operation June 1, 2031. No SCR will be added to Sherco 1. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

SHC1 2020 & SHC2 2020

This is the “Preferred Plan with Retire 2 Units 2020” (Resource Plan Scenario 10E, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 1 and Sherco 2 will stop generating at the end of the year 2020. Both units will remain in standby operating condition until they are retired June 1, 2021. A replacement combined cycle generator will be constructed at the Black Dog site and begin operation June 1, 2026. An additional replacement combined cycle generator will be constructed at the Sherco site and begin operation June 1, 2031. No SCR will be added to Sherco 1 or to Sherco 2. On-going capital replacement projects continue for both units to maintain reliable operations. The level of investment declines a few years before retirement.

SHC1 2023 & SHC2 2020

This is the “Preferred Plan with Retire 1 Unit 2020, 1 Unit 2023” (Resource Plan Scenario 10F, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 2 will stop generating at the end of the year 2020. This unit will remain in standby operating condition until it is retired June 1, 2021. A replacement combined cycle generator will be constructed at the Black Dog site and begin operation June 1, 2024. No SCR will be added to Sherco 1. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

Sherco 1 will stop generating at the end of the year 2023. This unit will remain in operating status and be retired June 1, 2024. A replacement combined cycle generator will be constructed at the Sherco site and begin operation June 1, 2031. No SCR will be added to Sherco 2. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

DATA AND ASSUMPTIONS

NSP provided the research team with capital expenditures, operating expenditures, and revenue requirements for each scenario. The timing of operating and capital expenditures is specific to each scenario. The research team worked under the assumption that the company provided good-faith estimates for each scenario. For modeling purposes, cost assumptions were provided in nominal dollars. For comparison purposes, NSP converted inputs from nominal to real dollars using internal deflators. Costs in real dollars are presented in the following section.

Real costs were entered into the REMI model based on total activity expenditures. The researchers deferred to the model for the local purchasing coefficients for inputs given that three subregions are specified for this study. This reduces subjectivity and error associated with obtaining the source and composition of labor, capital, and intermediate inputs to production by community from NSP. The local purchasing coefficients within REMI change over time based on changing demand.

Capital Expenditures

The lowest capital cost scenario is the SHC1 2020 & SHC2 2020 in which NSP continues to operate Sherco units 1 and 2 until 2020 and then replaces them with combined cycle units at the Black Dog site and the Sherco site. This scenario, as shown in Table 5, has an estimated capital cost of $1.6 billion between 2015 and 2040, which includes on-going capital needs to repair and replace individual components to reliably continue operation of both units until 2020.

Alternatively, the baseline scenario is the highest capital cost scenario, estimated at nearly $1.9 billion as both Sherco units 1 and 2 in Sherburne County are retired in 2031 and are replaced with combined cycle generating units in Dakota County and Sherburne County (Table 5 and Table 6).

TABLE 5: CAPITAL EXPENDITURES (2014 DOLLARS), 2015–2040

Scenario	Total Spending (Millions)	Difference from Baseline (Millions)	Percentage Change
Baseline	$1,860.8	$0.0	0.0%
SHC1 2031 & SHC2 2025	$1,814.6	-$46.2	-2.5%
SHC1 2025 & SHC2 2025	$1,812.7	-$48.1	-2.6%
SHC1 2020 & SHC2 2020	$1,631.1	-$229.7	-12.3%
SHC1 2023 & SHC2 2020	$1,689.7	-$171.1	-9.2%

TABLE 6: CHANGE IN CAPITAL EXPENDITURES BY LOCATION (2014 DOLLARS), 2015–2040

Scenario	Difference in Sherburne County (Millions)	Difference in Dakota County (Millions)	Difference from Baseline (Millions)
Baseline	$0.0	$0.0	$0.0
SHC1 2031 & SHC2 2025	-$63.0	$16.8	-$46.2
SHC1 2025 & SHC2 2025	-$65.0	$16.8	-$48.1
SHC1 2020 & SHC2 2020	-$246.5	$16.8	-$229.7
SHC1 2023 & SHC2 2020	-$194.6	$23.5	-171.1

Operating and Maintenance

In addition to the consideration of capital expenditures, fixed and variable operating and maintenance costs vary by scenario. At $982 million, the baseline scenario has the highest operating and maintenance costs—3.5% to 25.8% higher than the alternative scenarios (Table 7). The various retirement and replacement scenarios reduce total fixed and variable operating costs.

TABLE 7: OPERATING EXPENDITURES (2014 DOLLARS), 2015–2040

Scenario	Total Fixed Operating and Maintenance (Millions)	Total Variable Operating and Maintenance (Millions)	Total Spending (Millions)	Difference from Baseline (Millions)	Percentage Change
Baseline	$923.0	$59.1	$982.0	$0.0	0.0%
SHC1 2031 & SHC2 2025	$897.6	$49.9	$947.5	-$34.5	-3.5%
SHC1 2025 & SHC2 2025	$855.3	$39.3	$894.6	-$87.4	-8.9%
SHC1 2020 & SHC2 2020	$663.1	$65.2	$728.3	-$253.7	-25.8%
SHC1 2023 & SHC2 2020	$715.2	$43.7	$758.9	-$223.1	-22.7%

Total fixed and variable operating costs would increase in Dakota County under the alternative scenarios, while costs would decrease in Sherburne County (Table 8).

TABLE 8: CHANGE IN OPERATING EXPENDITURES (2014 DOLLARS), 2015–2040

Scenario	Difference in Sherburne County (Millions)	Difference in Dakota County (Millions)	Difference from Baseline (Millions)
Baseline	$0.0	$0.0	$0.0
SHC1 2031 & SHC2 2025	-$64.5	$30.0	-$34.5
SHC1 2025 & SHC2 2025	-$117.1	$29.7	-$87.4
SHC1 2020 & SHC2 2020	-$310.5	$56.8	-$253.7
SHC1 2023 & SHC2 2020	-$264.8	$41.6	-$223.1

Property Taxes

Property taxes were a separate consideration given the location of the alternative scenarios. While other taxes, such as income taxes and sales taxes, are important considerations, property taxes are particularly important because of the localized impact of the revenue stream. The tax impact was not explicitly modeled in this study. However, a reduction in activity at Sherco would result in a reduction in property taxes in Sherburne County, and an increase in activity at Black Dog would result in an increase in property taxes in Dakota County.

Revenue Requirements

Based on the level of operation and capital expenditures detailed in this report, NSP estimated the increase in revenue requirements included in electricity rates for electric customers for the four early retirement scenarios compared to the baseline scenario. This effectively isolates the revenue requirements and the electricity rate impact for the alternative scenarios and holds economic growth and electricity demand constant.[2] Revenue requirements are not equal to the sum of operation and capital expenditures because capital expenditures are recovered over the life of the asset. Therefore, revenue requirements occur over the life of the asset and include both a return of and return on capital. The revenue requirements estimate the additional electric revenues that would be recovered from customers for each scenario, despite the location of the supply chain for operating and capital purchases. At $1.1 billion, the change in revenue requirements is largest for the SHC1 2020 & SHC2 2020 Scenario between 2015 and 2040 (Table 9). Changes in revenue requirements were applied to residential, commercial, and industrial customers in Minnesota.

TABLE 9: CHANGE IN REVENUE REQUIREMENTS FOR MINNESOTA CUSTOMERS (NOMINAL), 2015–2040

Scenario	Dollar Change (Millions)	Percentage Change
Baseline	$0.0	0.0%
SHC1 2031 & SHC2 2025	$146.6	0.1%
SHC1 2025 & SHC2 2025	$806.4	0.7%
SHC1 2020 & SHC2 2020	$1,111.9	0.9%
SHC1 2023 & SHC2 2020	$826.9	0.7%

RESULTS

Continued operation of and investments in Sherco units 1 and 2 will have an ongoing positive economic contribution to the Minnesota economy. Scenarios involving early retirement and replacement of one or both of the units would also have near-term economic benefits, but the economic benefits of the baseline scenario are comparatively larger than the early retirement scenarios. The extent of the economic impacts is affected by factors that include the retirement costs of existing generating units,

[2]Electricity costs were entered as fuel cost variables: “Electricity (Commercial Sectors) Fuel Cost (amount)” for nonresidential sectors, and “Consumer Price (amount) for the residential sector.”

the sources of inputs for capital investments, the ongoing operating costs, the sources of fuels, and the revenue requirements assigned to the customer base.

The retirement and replacement scenarios have varying degrees of impact on the Dakota County and Sherburne County economies. Retiring Sherco units in Sherburne County generates positive economic activity during the decommissioning phase but instills a negative economic cost during the other years due to lost operating and maintenance activity and to higher revenue requirements placed on residential and business utility customers. The construction and new operating activity at the Black Dog site in Dakota County would be a boost to the county economy, effectively outweighing the economic costs associated with higher revenue requirements. While these benefits accrue to Dakota County, it essentially shifts economic benefits from Sherburne County to Dakota County, and the overall impact on the Minnesota economy is marginally negative compared to the baseline scenario. The economic impacts of the retirement and replacement scenarios may appear large in absolute values, but the percentage change of the impacts is relatively small compared to the magnitude of the overall Minnesota economy. Accordingly, the impacts are not recessionary—the economy continues on a trajectory of growth, albeit slightly slower growth.

To quantify the economic contribution of the baseline scenario, the projected capital expenditures and operating expenditures from 2015 through 2040 were removed from the Minnesota economy. The resulting decrease in economic activity is the economic contribution of projected operations. This analysis excludes the revenue requirements associated with current operations of Sherco 1 and 2 since those revenue requirements are imbedded in the overall system revenue requirements for the company. The alternative scenarios were modeled using the changes in spending compared to baseline scenario on capital expenditures, operating expenditures, taxes, and revenue requirements. The revenue requirements for the alternative scenarios were supplied for the overall system, and it was possible to model the impact of *change* in revenue requirements for the retirement scenarios because the only system changes between the baseline scenario and the retirement scenarios include the retirement and replacement effects. Everything else in the system was left unchanged.

The following is a net analysis, examining the benefits as well as the costs. The growing demand for energy and plant energy output is controlled by comparing the economic impacts of the retirement scenarios to the baseline scenario. This section reports the impacts in fixed (2014) dollars and the following paragraphs summarize the economic impacts by scenario.

Baseline Scenario Economic Contribution

In terms of economic contributions to the state of Minnesota, the baseline scenario, which includes continued long-term operation of Sherco units 1 and 2 until retirement and replacement in 2031, yields 980 jobs on average over the 26-year time horizon (Table 10). The baseline scenario would yield a contribution to total GDP of $2.8 billion in fixed 2014 dollars over the forecast horizon from 2015–2040, excluding the revenue requirements to customers.[3,4] Despite the Sherburne County location of Sherco units 1 and 2, the economic benefits of capital and operating expenditures extend beyond Sherburne County as direct and indirect goods and services are purchased from vendors throughout the state and as employee disposable income is spent in the larger Minnesota economy. Detailed results are available in Appendices 2,3, and 4.

TABLE 10: ECONOMIC CONTRIBUTION OF SHERCO 1 AND 2, AVERAGE 2015–2040

Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs[1]	527	228	224	980
	Percent Change	*1.3%*	*0.1%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	465	215	205	885
	Percent Change	*1.3%*	*0.1%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	65,815	25,391	16,065	107,273
	Percent Change	*1.7%*	*0.1%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	40,606	15,168	14,369	70,141
	Percent Change	*0.9%*	*0.1%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars. Note: The baseline scenario is the total economic impact (excluding rate impact); other scenarios are in comparison to the baseline scenario.

SHC1 2031 & SHC2 2025 Economic Impacts

This scenario includes the retirement of Sherco 2 in 2025 and its replacement with a combined cycle generator at Black Dog, and the retirement of Sherco 1 in 2031 and its replacement with a combined cycle generator at Sherco. This early retirement scenario has the second-highest capital expenditures and operating costs, and the second-lowest revenue requirements. This scenario records mixed economic impacts on the Minnesota economy and on Sherburne and Dakota counties. Economic benefits are recorded during the intensive decommissioning and construction phases, while economic costs are generally recorded during the nonconstruction phases. This is due to the rate burden on

[3] Revenue requirements for each scenario are calculated for the entire NSP system rather than just for Sherco 1 and 2.

[4] Total contributions to GDP are summed over the entire period while averages are shown in Table 10 (26 years times $107,273K equals $2.8 billion).

consumers (both residential and commercial/industrial) as the higher revenue requirements overshadow the benefits associated with construction activity and lower operating costs. The higher revenue requirements are levied on all customers, while the economic benefit from construction is diluted due to leakage—some goods and services are sourced from outside the state.

The costs and benefits are not shared equally by location in Minnesota—Dakota County is a net beneficiary while Sherburne County and the rest of Minnesota incur higher costs. These deviations are relatively small compared to the overall Minnesota economy, while they are slightly larger in Sherburne County and Dakota County. The magnitude and periodic variation in economic impacts is apparent in the private employment figures. Compared to the baseline scenario, over the 26-year horizon, Sherburne County employment is lower by an average of 31 jobs per year, Dakota County is higher by an average of 18 jobs per year, and the rest of Minnesota is lower by an average of 62 jobs per year, as shown in Table 11.

TABLE 11: SHC1 2031 & SHC2 2025 ECONOMIC IMPACTS COMPARED TO BASELINE, AVERAGE 2015–2040

Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs[1]	-31	18	-62	-75
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	-27	16	-46	-57
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	-4,097	-445	-11,479	-16,021
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,406	-714	-10,602	-13,719
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars.

Since this scenario involves generator retirement and replacement sooner than the baseline scenario, the spike and dip in economic activity is largely due to timing—specifically the timing of activity compared to the baseline scenario. Retiring Sherco 2 in 2025 instead of 2031 increases economic activity in the 2020s, but decreases economic activity in the 2030s—hence, the spike in employment followed by the decrease. (See Figure 5.)

As shown in Figure 5, Dakota County records the greatest employment impact. This is due to the new construction and operations within Dakota County. Sherburne County records only a modest dip in employment, buoyed by activity during the Sherco unit shutdown and decommissioning phase.

FIGURE 5: SHC1 2031 & SHC2 2025 IMPACT ON PRIVATE EMPLOYMENT

Total capital spending and operating and maintenance costs for this early retirement scenario are less than those for the baseline scenario. Revenue requirements are greater than in the baseline scenario, and this increase is greater than the decrease in total operating costs. The economic impacts are tempered, however, due the size of these impacts relative to the large local economy. The Minnesota economy ranked 17th nationally in 2014 in terms of state GDP at $316 billion and 17th in terms of employment at 2.8 million. As shown in Table 11, slower growth in GDP of $16 million and 75 fewer jobs represent less than one-tenth of a percent change in economic growth statewide. The impacts are greater for Sherburne County and Dakota County given they are the locations incurring the greatest operating changes.

SHC1 2025 & SHC2 2025 Economic Impacts

This scenario includes the retirement of Sherco units 1 and 2 in 2025, replaced with combined cycle generators at Sherco and Black Dog. This scenario has the third-highest fixed capital costs, operating costs, and revenue requirements, and records mixed economic impacts on the Minnesota economy and on Sherburne and Dakota counties. Economic benefits are recorded during the intensive decommissioning and construction phases, while economic costs are generally recorded during the nonconstruction phases. This is due to the rate burden on residential and business consumers as the higher revenue requirements overshadow the benefits associated with construction activity and lower operating costs. The higher revenue requirements are levied on all customers, while the economic benefit from construction is diluted due to leakage—some goods and services are sourced from outside the state.

The costs and benefits are not shared equally by location in Minnesota—Dakota County is a net beneficiary while Sherburne County and the rest of Minnesota incur higher costs. These deviations are relatively small compared to the overall Minnesota economy, although slightly larger relative impacts are recorded in Sherburne County and Dakota County. The magnitude and periodic variation in economic impacts is apparent in the private employment figures. As shown in Table 12, over the 26-year horizon, Sherburne County employment is lower by an average of 22 jobs, Dakota County is flat, and the rest of Minnesota is lower by 237 jobs compared to the baseline scenario.

TABLE 12: SHC1 2025 & SHC2 2025 ECONOMIC IMPACTS COMPARED TO BASELINE, AVE. 2015–2040

Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs[1]	-22	0.2	-237	-258
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	-22	0	-187	-209
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	-6,863	-3,757	-42,640	-53,257
	Percent Change	*-0.2%*	*0.0%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,920	-4,508	-40,494	-47,919
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars.

Since this scenario involves generator retirement and replacement sooner than the baseline scenario, the spike and dip in economic activity is largely due to timing. Retiring Sherco 1 and Sherco 2 in 2025 instead of 2031 increases economic activity in the 2020s, but decreases economic activity in the 2030s—hence, the spike in employment followed by the decrease. (See Figure 6.)

Visible in Figure 6, Dakota County records the greatest employment impact. This is due to the new construction and operations within Dakota County. Sherburne County only records a modest dip in employment, buoyed by activity during the decommissioning phase and the reconstruction of Sherco 1.

FIGURE 6: SHC1 2025 & SHC2 2025 IMPACT ON PRIVATE EMPLOYMENT

Despite the decrease in total capital spending and decrease in operating and maintenance costs for this early retirement scenario, the economic impacts are dampened by the project horizon, the higher revenue requirements, and the relatively large local economy. The Minnesota economy ranked 17th nationally in 2014 in terms of state GDP at $316 billion and 17th in terms of employment at 2.8 million. Slower growth in GDP of $53 million and 258 fewer jobs represent less than one-tenth of a percent change in economic growth statewide (Table 12). The impacts are greater for Sherburne County and Dakota County given they are the locations incurring the greatest operating changes.

SHC1 2020 & SHC2 2020 Economic Impacts

This scenario includes placing Sherco 1 and 2 in standby mode in 2020, replaced with new combined cycle generators at Black Dog in 2026 and at Sherco in 2031. This scenario has the lowest fixed capital costs and operating costs and the highest revenue requirements, and records mixed economic impacts on the Minnesota economy and on Sherburne and Dakota counties. Economic benefits are recorded during the intensive decommissioning and construction phases, while economic costs are generally recorded during the nonconstruction phases. This is due to the rate burden on residential and business consumers as the higher revenue requirements overshadow the benefits associated with construction activity and lower operating costs. The higher revenue requirements are levied on all customers, while the economic benefit from construction is diluted due to leakage—some goods and services are sourced from outside the state.

The costs and benefits are not shared equally by location in Minnesota—Dakota County averages modest employment losses despite gaining a generating facility—mostly due to the delayed replacement facility in Dakota County. Sherburne County loses some operating activity and the rest of Minnesota incurs higher utility costs. These deviations are relatively small compared to the overall Minnesota economy, although slightly larger relative impacts are incurred in Sherburne County and Dakota County. The magnitude and periodic variation in economic impacts is apparent in the private employment figures. As shown in Table 13, over the 26-year horizon, Sherburne County employment is lower by an average of 140 jobs, Dakota County is lower by an average of 12 jobs, and the rest of Minnesota is lower by 418 jobs compared to the baseline scenario.

TABLE 13: SHC1 2020 & SHC2 2020 ECONOMIC IMPACTS COMPARED TO BASELINE, AVERAGE 2015–2040

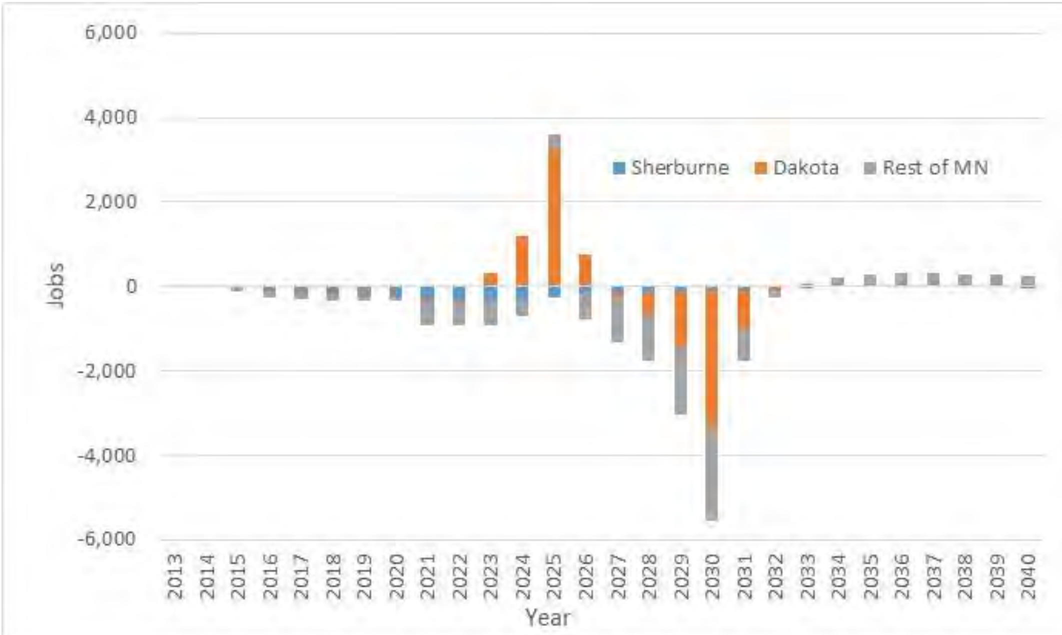
Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs	-140	-12	-418	-570
	Percent Change	*-0.3%*	*0.0%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	-121	-10	-334	-465
	Percent Change	*-0.3%*	*0.0%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	-18,871	-5,751	-65,339	-89,966
	Percent Change	*-0.5%*	*0.0%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-10,584	-6,641	-66,262	-83,485
	Percent Change	*-0.2%*	*0.0%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars.

Since this scenario involves generator retirement and replacement sooner than the baseline scenario, the spike and dip in economic activity is largely due to timing. Retiring Sherco 1 and Sherco 2 in 2020 instead of 2031 increases economic activity in the 2020s, but decreases economic activity in the 2030s—hence, the spike in employment followed by the decrease. (See Figure 7.)

As Figure 7 shows, Dakota County records the greatest employment impact. This is due to the new construction and operations within the county. Sherburne County only records a modest dip in employment, buoyed by activity during the decommissioning phase and the construction of a natural gas combined cycle unit at the Sherco site.

FIGURE 7: SHC1 2020 & SHC2 2020 IMPACT ON PRIVATE EMPLOYMENT



Despite the decrease in total capital spending operating and maintenance costs for this early retirement scenario, the economic impacts are dampened by the project horizon, the higher revenue requirements, and the relatively large local economy. The Minnesota economy ranked 17th nationally in 2014 in terms of state GDP at $316 billion and 17th in term of employment at 2.8 million. Slower growth in GDP of $90 million and 570 fewer total jobs represent less than one-tenth of a percent change in economic growth statewide. The impacts are greater for Sherburne County and Dakota County given they are the locations incurring the greatest operating changes.

SHC1 2023 & SHC2 2020 Economic Impacts

This scenario includes the retirement of Sherco 2 in 2020, replaced with a combined cycle generator at Black Dog, and the retirement of Sherco 1 in 2023, replaced with a combined cycle generator at Sherco. This alternative scenario has the second-lowest fixed capital costs and operating costs, and the second-highest revenue requirements, and records mixed economic impacts on the Minnesota economy and on Sherburne and Dakota Counties. Economic benefits are recorded during the intensive decommissioning and construction phases, while economic costs are generally recorded during the nonconstruction phases. This is due to the rate burden on residential and business consumers as the higher revenue requirements overshadow the benefits associated with construction activity and lower operating costs.

The higher revenue requirements are levied on all customers, while the economic benefit from construction is diluted due to leakage—some goods and services are sourced from outside the state.

The costs and benefits are not shared equally by location in Minnesota—Dakota County and Sherburne County record a net increase in economic activity, while the rest of Minnesota incurs higher utility costs. However, these deviations are relatively small compared to the overall Minnesota economy. The magnitude and periodic variation in economic impacts is apparent in the private employment figures. As shown in Table 14, over the 26-year horizon, Sherburne County employment is higher by an average of 5 jobs, Dakota County is higher by an average of 7 jobs, and the rest of Minnesota is lower by 313 jobs compared to the baseline projection.

TABLE 14: SHC1 2020 & SHC2 2023 ECONOMIC IMPACTS COMPARED TO BASELINE, AVERAGE 2015–2040

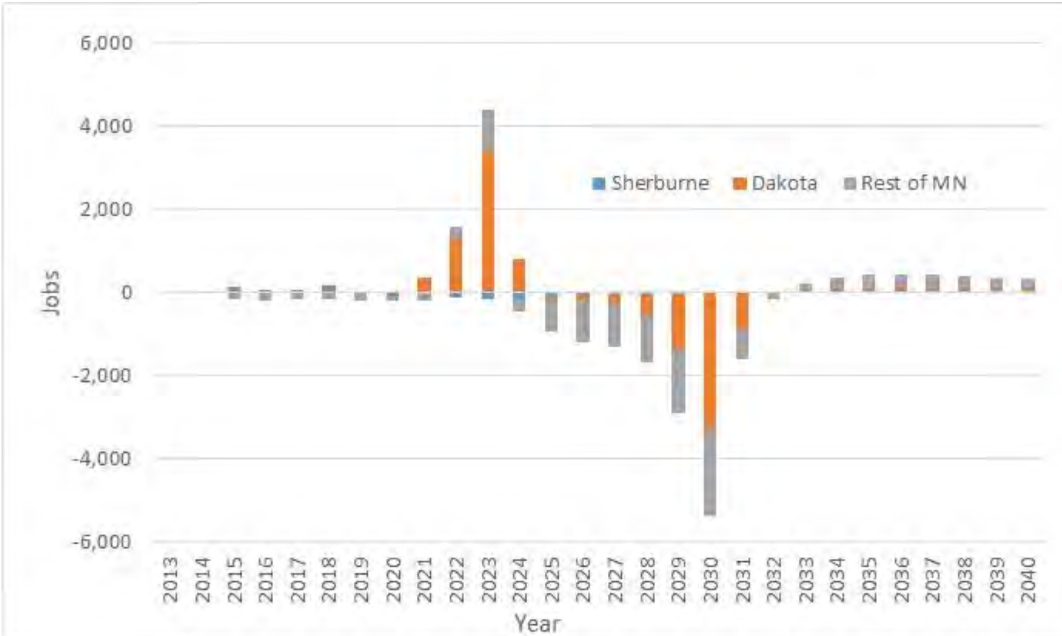
Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs[1]	5	7	-313	-300
	Percent Change	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	2	8	-248	-239
	Percent Change	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	13,737	-3,430	-60,123	-49,813
	Percent Change	*0.4%*	*0.0%*	*0.0%*	*0.0%*
Personal Income	Dollars (Thousands)[1]	2,668	-5,182	-49,930	-52,443
	Percent Change	*0.1%*	*0.0%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	5	7	-313	-300
	Percent Change	*0.0%*	*0.0%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars.

Since this scenario involves generator retirement and replacement sooner than the baseline scenario, the spikes and dips in economic activity are largely due to timing. Retiring Sherco 1 in 2023 instead of 2031, and retiring Sherco 2 in 2020 instead of 2031 increases economic activity in the 2020s, but decreases economic activity in the 2030s—hence, the spike in employment followed by the decrease. (See Figure 8.)

As Figure 8 indicates, Dakota County records the greatest employment impact. This is due to the new construction and operations within Dakota County. Sherburne County records only a modest dip in employment, buoyed by activity during the decommissioning phase and the construction of a natural gas combined cycle unit at the Sherco site.

FIGURE 8: SHC1 2023 & SHC2 2020 IMPACT ON PRIVATE EMPLOYMENT



Despite the decrease in total capital spending and operating and maintenance costs for this early retirement scenario, the economic impacts are dampened by the project horizon, the higher revenue requirements, and the relatively large local economy. The Minnesota economy ranked 17th nationally in 2014 in terms of state GDP at $316 billion and 17th in term of employment at 2.8 million. Slower growth in GDP of $50 million and 300 fewer total jobs represent less than one-tenth of a percent change in economic growth statewide. The impacts are greater for Sherburne County and Dakota County given they are the locations incurring the greatest operating changes.

CONCLUSION

This paper provides an analysis of the economic impact of early retirement and replacement of the coal-fired Sherco 1 and Sherco 2 units with an equivalent MW amount of combined cycle gas-fired generation capacity. This report finds the costs associated with an increase in revenue requirements to pay for early retirement and replacement are modestly greater than the economic benefits associated with the change in capital investments and operating costs.

This analysis uses data on operations, maintenance, capital expenditures, and revenue requirements provided by NSP on the current Sherco 1 and 2 units and on four retirement scenarios.

Overall, the study found the following:

- Current Sherco operations have an impact that extends beyond Sherburne County as NSP purchases goods and services from vendors throughout Minnesota and as income earners spend disposable personal income throughout the state.
- Some of the construction and operating benefits do not impact the Minnesota economy as goods and services are sourced from out of state while the increase in revenue requirements (costs) are placed on all Minnesota NSP customers (residential, commercial, and industrial).
- The lack of indigenous fossil resources in Minnesota limits potential gains in fuel switching. Since Minnesota does not have indigenous coal or natural gas resources, it necessitates importing fuel from other states and requiring gas pipeline upgrades.
- The baseline scenario and each early retirement scenario require additional investments in gas pipelines and transmission totaling about 10% of total capital expenditures.
- All early Sherco retirement scenarios will result in higher revenue requirements of $147 million–$1.7 billion, or 0.1%–0.9% for NSP's Minnesota electricity customers, partially due to fuel costs. This negative economic impact is greater than the economic benefits associated with the construction of replacement generation and changes in operations.
- Continued operation of and investments in Sherco units 1 and 2 through 2031 will have the greatest ongoing positive impact to the Minnesota economy.
- Compared to the baseline scenario, all early Sherco retirement scenarios result in comparatively slower growth within the Minnesota economy in terms of:
    - Employment (-75 to -570 jobs on average)
    - GDP (-$16 million to -$90 million on average), and

    - Real disposable personal income (-$14 million to -$83 million).

  Note: These changes represent a relatively small percentage of the overall Minnesota economy, Sherburne County economy, and Dakota County economy, and none of the scenarios are recessionary.

- The statewide economic losses compared to the baseline scenario increase as the retirement of Sherco units are moved to earlier dates because of the need for earlier capital expenditures and increased costs to rate payers.
    - Scenario SHC1 2020 & SHC2 2020 results in the greatest statewide decrease in GDP compared to the baseline scenario.
    - The SHC1 2031 & SHC2 2025 retirement scenario results in the smallest economic loss compared to the baseline scenario.
- As a percentage of local economic activity, Sherburne County experiences the greatest negative impact under most retirement scenarios due to the reduction in local operating activity, while Dakota County records the largest positive impacts due to the construction of replacement generation at the Black Dog site. The study period impacts are generally a decrease in employment in Sherburne County, as well as a shift of employment from Sherburne County to Dakota County. Construction of replacement generation on the Sherco site buffers some of the negative economic impacts associated with lost generation.

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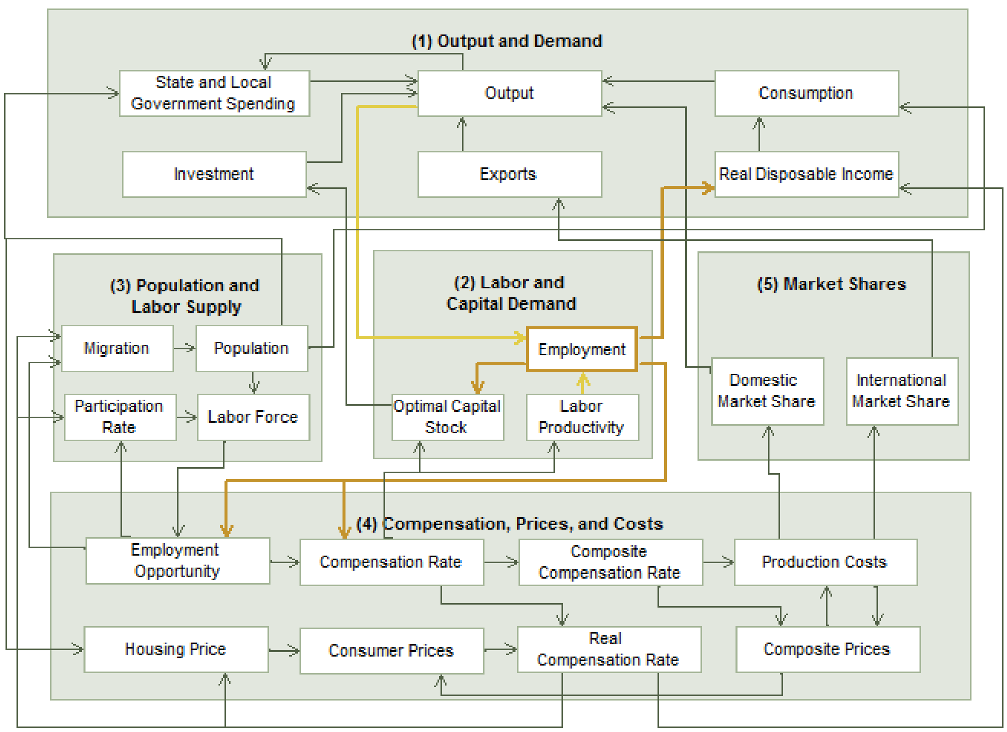
APPENDIX 1: OVERVIEW OF REMI POLICY INSIGHT

This summary was provided by REMI, Inc.

Policy Insight is a structural economic forecasting and policy analysis model. It integrates input-output, computable general equilibrium, econometric, and economic geography methodologies. The model is dynamic, with forecasts and simulations generated on an annual basis and behavioral responses to wage, price, and other economic factors.

The REMI model consists of thousands of simultaneous equations with a structure that is relatively straightforward. The exact number of equations used varies depending on the extent of industry, demographic, demand, and other detail in the model. The overall structure of the model can be summarized in five major blocks: (1) Output and Demand, (2) Labor and Capital Demand, (3) Population and Labor Supply, (4) Wages, Prices and Costs, and (5) Market Shares.



Block 1. Output and Demand

This block includes output, demand, consumption, investment, government spending, import, product access, and export concepts. For each industry, demand is determined by the amount of output, consumption, investment and capital demand on that industry. Consumption depends on real disposable income per capita, relative prices, differential income elasticities and population. Input productivity depends on access to inputs because the larger the choice set of inputs, the more likely that the input with the specific characteristics required for the job will be formed. In the capital stock adjustment process, investment occurs to fill the difference between optimal and actual capital stock for residential, non-residential, and equipment investment. Government spending changes are determined by changes in the population.

Block 2. Labor and Capital Demand

The Labor and Capital Demand block includes the determination of labor productivity, labor intensity and the optimal capital stocks. Industry-specific labor productivity depends on the availability of workers with differentiated skills for the occupations used in each industry. The occupational labor supply and commuting costs determine firms' access to a specialized labor force.

Labor intensity is determined by the cost of labor relative to the other factor inputs, capital and fuel. Demand for capital is driven by the optimal capital stock equation for both non-residential capital and equipment. Optimal capital stock for each industry depends on the relative cost of labor and capital, and the employment weighted by capital use for each industry. Employment in private industries is determined by the value added and employment per unit of value added in each industry.

Block 3. Population and Labor Supply

The Population and Labor Supply block includes detailed demographic information about the region. Population data is given for age and gender, with birth and survival rates for each group. The size and labor force participation rate of each group determines the labor supply. These participation rates respond to changes in employment relative to the potential labor force and to changes in the real after tax compensation rate. Migration includes retirement, military, international and economic migration. Economic migration is determined by the relative real after tax compensation rate, relative employment opportunity and consumer access to variety.

Block 4. Wages, Prices, and Costs

This block includes delivered prices, production costs, equipment cost, the consumption deflator, consumer prices, the price of housing, and the wage equation. Economic geography concepts account for the productivity and price effects of access to specialized labor, goods and services.
These prices measure the price of the industry output, taking into account the access to production locations. This access is important due to the specialization of production that takes place within each industry, and because transportation and transaction costs of distance are significant. Composite prices for each industry are then calculated based on the production costs of supplying regions, the effective

distance to these regions, and the index of access to the variety of output in the industry relative to the access by other uses of the product.

The cost of production for each industry is determined by cost of labor, capital, fuel and intermediate inputs. Labor costs reflect a productivity adjustment to account for access to specialized labor, as well as underlying compensation rates. Capital costs include costs of non- residential structures and equipment, while fuel costs incorporate electricity, natural gas and residual fuels.

The consumption deflator converts industry prices to prices for consumption commodities. For potential migrants, the consumer price is additionally calculated to include housing prices. Housing price changes from their initial level depend on changes in income and population density.

Compensation changes are due to changes in labor demand and supply conditions and changes in the national compensation rate. Changes in employment opportunities relative to the labor force and occupational demand change determine compensation rates by industry.

Block 5. Market Shares

The Market Shares equations measure the proportion of local and export markets that are captured by each industry. These depend on relative production costs, the estimated price elasticity of demand, and effective distance between the home region and each of the other regions. The change in share of a specific area in any region depends on changes in its delivered price and the quantity it produces compared with the same factors for competitors in that market. The share of local and external markets then drives the exports from and imports to the home economy.

The Labor and Capital Demand block includes labor intensity and productivity as well as demand for labor and capital. Labor force participation rate and migration equations are in the Population and Labor Supply block. The Wages, Prices, and Costs block includes composite prices, determinants of production costs, the consumption price deflator, housing prices, and the wage equations. The proportion of local, inter-regional and export markets captured by each region is included in the Market Shares block.

APPENDIX 2: DETAILED ECONOMIC IMPACTS OF SCENARIOS ON THE MINNESOTA ECONOMY

The following tables exhibit the economic impacts of the baseline scenario on the Minnesota economy, as well as the economic impacts of the alternative scenarios compared to the baseline scenario.

TABLE 15: ECONOMIC CONTRIBUTION OF BASELINE SCENARIO ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	545	511	631	3,115	241	980
Private Non-Farm Employment	Jobs	515	454	567	2,920	112	885
Gross Domestic Product	Dollars (Thousands)[1]	58,758	56,019	73,325	345,997	18,944	107,273
Real Disposable Personal Income	Dollars (Thousands)[1]	29,475	33,754	45,510	207,539	40,525	70,141

[1]Dollars are fixed (2014) dollars. Note: Scenario 1 is the total economic impact (excluding rate impact); other scenarios are in comparison to Scenario 1.

TABLE 16: ECONOMIC CONTRIBUTION OF SHC1 2031 & SHC2 2025 ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-23	349	286	-1,286	246	-75
Private Non-Farm Employment	Jobs	-21	348	262	-1,192	269	-57
Gross Domestic Product	Dollars (Thousands)[1]	-2,656	36,698	6,624	-161,786	32,256	-16,021
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,813	17,126	-32,173	-83,661	25,542	-13,719

[1]Dollars are fixed (2014) dollars. Note: The decrease in economic activity from 2016-2020 and the increase in economic activity from 2021-2025 is due to timing of expenditures in this scenario compared to the alternative scenario.

TABLE 17: ECONOMIC CONTRIBUTION OF SHC1 2025 & SHC2 2025 ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-50	895	395	-2,874	245	-258
Private Non-Farm Employment	Jobs	-46	884	332	-2,650	339	-209
Gross Domestic Product	Dollars (Thousands)[1]	-5,747	85,523	-16,608	-360,954	17,216	-53,257
Real Disposable Personal Income	Dollars (Thousands)[1]	-6,365	40,301	-89,229	-211,488	14,438	-47,919

[1]Dollars are fixed (2014) dollars. Note: The decrease in economic activity from 2016-2020 and the increase in economic activity from 2021-2025 is due to timing of expenditures in this scenario compared to the alternative scenario.

TABLE 18: ECONOMIC CONTRIBUTION OF SHC1 2020 & SHC2 2020 ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-293	-545	-681	-1,687	207	-570
Private Non-Farm Employment	Jobs	-276	-472	-554	-1,463	300	-465
Gross Domestic Product	Dollars (Thousands)[1]	-28,154	-72,538	-135,514	-239,782	6,515	-89,966
Real Disposable Personal Income	Dollars (Thousands)[1]	-23,050	-93,037	-171,610	-151,162	4,032	-83,485

[1]Dollars are fixed (2014) dollars. Note: The decrease in economic activity from 2016-2020 and the increase in economic activity from 2021-2025 is due to timing of expenditures in this scenario compared to the alternative scenario.

TABLE 19: ECONOMIC CONTRIBUTION OF SHC1 2023 & SHC2 2020 ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-71	1,252	-1,683	-1,481	361	-300
Private Non-Farm Employment	Jobs	-70	1,231	-1,597	-1,294	423	-239
Gross Domestic Product	Dollars (Thousands)[1]	3,270	128,358	-229,536	-202,810	35,226	-49,813
Real Disposable Personal Income	Dollars (Thousands)[1]	-8,685	42,906	-218,317	-123,437	29,645	-52,443

[1]Dollars are fixed (2014) dollars. Note: The decrease in economic activity from 2016-2020 and the increase in economic activity from 2021-2025 is due to timing of expenditures in this scenario compared to the alternative scenario.

APPENDIX 3: DETAILED ECONOMIC IMPACTS OF SCENARIOS ON SHERBURNE COUNTY

The following tables exhibit the economic impacts of the baseline scenario on the Sherburne County economy, as well as the economic impacts of the alternative scenarios compared to the baseline scenario.

TABLE 20: CONTRIBUTION OF BASELINE SCENARIO ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	490	430	422	1,242	136	527
Private Non-Farm Employment	Jobs	461	378	367	1,135	63	465
Gross Domestic Product	Dollars (Thousands)[1]	66,831	58,796	62,471	132,322	18,373	65,815
Real Disposable Personal Income	Dollars (Thousands)[1]	26,949	30,386	32,658	85,887	30,426	40,606

[1]Dollars are fixed (2014) dollars. Note: Scenario 1 is the total economic impact (excluding rate impact); other scenarios are in comparison to Scenario 1.

TABLE 21: CONTRIBUTION OF SHC1 2031 & SHC2 2025 ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	0	-55	-79	-26	-1	-31
Private Non-Farm Employment	Jobs	0	-54	-72	-18	3	-27
Gross Domestic Product	Dollars (Thousands)[1]	-25	-3,045	-14,301	-4,458	455	-4,097
Real Disposable Personal Income	Dollars (Thousands)[1]	7	-2,180	-5,664	-3,457	-1,052	-2,406

[1]Dollars are fixed (2014) dollars.

TABLE 22: CONTRIBUTION OF SHC1 2025 & SHC2 2025 ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	0	392	422	-911	-17	-22
Private Non-Farm Employment	Jobs	0	383	357	-870	12	-22
Gross Domestic Product	Dollars (Thousands)[1]	-58	34,907	22,691	-93,905	324	-6,863
Real Disposable Personal Income	Dollars (Thousands)[1]	-8	18,054	31,922	-54,491	-9,707	-2,920

[1]Dollars are fixed (2014) dollars.

TABLE 23: CONTRIBUTION OF SHC1 2020 & SHC2 2020 ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-129	-325	-204	-62	-5	-140
Private Non-Farm Employment	Jobs	-124	-302	-172	-38	6	-121
Gross Domestic Product	Dollars (Thousands)[1]	-9,864	-39,616	-37,735	-12,002	981	-18,871
Real Disposable Personal Income	Dollars (Thousands)[1]	-5,567	-18,993	-17,643	-9,094	-3,171	-10,584

[1]Dollars are fixed (2014) dollars.

TABLE 24: CONTRIBUTION OF SHC1 2023 & SHC2 2020 ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	106	-92	-69	30	44	5
Private Non-Farm Employment	Jobs	95	-100	-67	31	41	2
Gross Domestic Product	Dollars (Thousands)[1]	35,663	7,779	-2,351	12,822	14,728	13,737
Real Disposable Personal Income	Dollars (Thousands)[1]	9,369	39	-3,123	2,171	4,463	2,668

[1]Dollars are fixed (2014) dollars.

APPENDIX 4: DETAILED ECONOMIC IMPACTS OF SCENARIOS ON DAKOTA COUNTY

The following tables exhibit the economic impacts of the baseline scenario on the Dakota County economy, as well as the economic impacts of the alternative scenarios compared to the baseline scenario.

TABLE 25: CONTRIBUTION OF BASELINE SCENARIO ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	1	1	78	1,065	36	228
Private Non-Farm Employment	Jobs	1	1	77	1,026	10	215
Gross Domestic Product	Dollars (Thousands)[1]	-535	-422	8,014	121,058	2,954	25,391
Real Disposable Personal Income	Dollars (Thousands)[1]	-84	-251	3,445	62,511	11,543	15,168

[1]Dollars are fixed (2014) dollars. Note: Scenario 1 is the total economic impact (excluding rate impact); other scenarios are in comparison to Scenario 1.

TABLE 26: CONTRIBUTION OF SHC1 2031 & SHC2 2025 ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-3	338	535	-820	39	18
Private Non-Farm Employment	Jobs	-3	333	495	-798	50	16
Gross Domestic Product	Dollars (Thousands)[1]	-286	33,672	51,237	-93,710	5,803	-445
Real Disposable Personal Income	Dollars (Thousands)[1]	-448	15,509	26,996	-44,887	-1,096	-714

[1]Dollars are fixed (2014) dollars.

TABLE 27: CONTRIBUTION OF SHC1 2025 & SHC2 2025 ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-6	341	489	-873	43	0
Private Non-Farm Employment	Jobs	-5	337	450	-845	56	0
Gross Domestic Product	Dollars (Thousands)[1]	-591	34,087	44,762	-102,846	4,291	-3,757
Real Disposable Personal Income	Dollars (Thousands)[1]	-873	15,510	16,888	-52,685	-2,282	-4,508

[1]Dollars are fixed (2014) dollars.

TABLE 28: CONTRIBUTION OF SHC1 2020 & SHC2 2020 ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-15	281	460	-845	47	-12
Private Non-Farm Employment	Jobs	-14	280	427	-816	60	-10
Gross Domestic Product	Dollars (Thousands)[1]	-1,592	26,952	40,202	-99,992	3,826	-5,751
Real Disposable Personal Income	Dollars (Thousands)[1]	-1,867	6,144	13,960	-50,546	-2,247	-6,641

[1]Dollars are fixed (2014) dollars.

TABLE 29: CONTRIBUTION OF SHC1 2023 & SHC2 2020 ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-17	1,208	-393	-828	60	7
Private Non-Farm Employment	Jobs	-16	1,182	-418	-794	75	8
Gross Domestic Product	Dollars (Thousands)[1]	-2,437	118,085	-48,109	-95,211	8,425	-3,430
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,127	53,008	-24,533	-51,351	-2,038	-5,182

[1]Dollars are fixed (2014) dollars.

Attachment H
Preliminary Assessment of CO_2 Markets under the Clean Power Plan

We present this preliminary assessment of potential revenues from carbon dioxide (CO_2) credits in future markets under the Clean Power Plan (CPP), in response to requests by the Department of Commerce and Commissioners during the December 3, 2015 Minnesota Public Utilities Commission hearing.

Although our Current Preferred Plan is not primarily driven by the CPP, we believe this plan will not only achieve, but likely exceed, the CO_2 reductions that could be required of the Company under Minnesota's CPP State Plan. As a result, the Current Preferred Plan may generate excess reductions in the form of CO_2 allowances (if Minnesota's plan is mass-based) or Emission Rate Credits (if the plan is rate-based), which under the CPP would be tradable to the owners of other CPP-regulated units within the state or in other states. As long as Minnesota's plan allows the Company to monetize the value of these reductions on behalf of our customers, this value could be used to help reduce the rate impact of transitioning our generation portfolio to a much lower-carbon system.

This Attachment estimates the value to our customers of excess CO_2 reductions under two State Plan scenarios. However, we emphasize the preliminary nature of this assessment: both the size and value of the allowances or ERCs we generate, beyond those used for our own compliance, are subject to uncertainty because they depend on State Plan decisions yet to be made and predictions about prices in CO_2 credit markets not yet in existence.

A. CPP Final Rule, State Plans and CO_2 Credit Markets

The CPP final rule sets CO_2 targets, for 2022 and each year thereafter, for each of the states in our Upper Midwest System. The targets are provided in "rate-based" form (pounds of CO_2 per MWh, both specific to coal and gas units and for each state as a whole) and "mass-based" form (total tons of CO_2, by year, on aggregate for all the CPP-regulated units in a state). Only the Minnesota targets affect the Company directly, since we own and operate CPP-regulated units only in Minnesota; however, the costs and benefits of compliance will be shared among customers in all our five states.

The rule allows each state to develop a State Plan to achieve the targets, providing states considerable flexibility in how they do this. It allows EPA to impose a Federal

Plan on any state that fails to submit an approvable plan. Initial State Plan submittals are due in September 2016, with the option to seek an extension to September 2018 to submit a final plan. The Minnesota Pollution Control Agency (MPCA) is the lead agency with responsibility to develop Minnesota's State Plan, in consultation with other agencies and stakeholders. The Company has been an active participant in MPCA's stakeholder group, as well as similar processes in our other states and regional stakeholder processes, discussing State Plan design decisions. We have been working to identify areas of agreement among utilities and other stakeholders.

A key decision in State Plan design is whether to take a rate-based or mass-based approach. A rate-based approach would seek to achieve the pounds of CO_2 per MWh targets, either on a statewide level or using the subcategory rates specific to coal and natural gas combined cycle units, and would allow eligible activities – including renewable energy, energy efficiency, and nuclear uprates – to earn Emission Rate Credits (ERCs) that could be used by regulated units for compliance. A mass-based approach would seek to achieve the total tons of CO_2 targets, requiring all regulated units to surrender CO_2 allowances equivalent to their emissions in a compliance period.

One of the most important flexibility mechanisms in the CPP is the option for states to create CO_2 credit markets – i.e. allow the owners of CPP-regulated units in a state to transact CO_2 allowances or ERCs with other regulated units, or with other entities, within the state or in other states. This would enable regulated unit owners to purchase allowances or ERCs for compliance, if this is more cost-effective than reducing emissions on their own system, or sell allowances or ERCs, if a regulated unit owner is able cost-effectively to reduce emissions such that it holds more allowances or ERCs than it needs for compliance.

EPA views this compliance flexibility as key to containing costs, and appropriate for CO_2, since the climate benefits of reducing emissions are independent of location. EPA does not mandate that State Plans allow trading, but provides much of the necessary infrastructure, including presumptively approvable model trading rules, EPA-administered allowance and ERC tracking systems, accreditation of credit verifiers, etc. EPA also allows trading between State Plan states and states who accept a Federal Plan. However, EPA proposes that regulated units in mass-based states may only trade with those in other mass-based states, and units in rate-based states may only trade with those in other rate-based states.

Minnesota and the other states the Company serves in the Upper Midwest are all actively considering allowing CO_2 credit trading in their CPP State Plans. However, none of our states has yet determined whether their plan will be mass-based or rate-based, and because of EPA's proposed restriction on trading between rate and mass, the geographic scope and liquidity of future CO_2 credit markets is unknown.

B. Scenario Analysis: Potential Value of CO_2 Credits to Our Customers

The Current Preferred Plan includes actions – coal unit retirement, maintenance of nuclear units, renewable energy additions, and ongoing energy efficiency savings – that are projected to reduce CO_2 potentially beyond what the State Plan requires of the Company. These actions may put the Company in the position of being a net allowance or ERC seller, after the Company has surrendered sufficient allowances or ERCs to bring its own units into compliance. This section presents a preliminary analysis of the value to our customers of these actions, under different possible credit prices and State Plan designs.

Uncertainties affecting the size of the Company's allowance budget include whether Minnesota and other states in the region take mass-based or rate-based approaches to compliance, how the State Plan allocates allowances in a mass-based approach, and which actions are eligible for ERC issuance in a rate-based approach. Uncertainties affecting the price obtainable for any allowances or ERCs include whether states allow trading in their plans, how much EPA's proposed restriction on trading between rate and mass limits the geographic scope and liquidity of CO_2 credit markets, and the structure of CO_2 credit markets that may emerge.

1. *Credit Prices*

Estimating the market value of CO_2 reductions requires assuming a price for allowances or ERCs in markets not yet in existence. The Commission's current regulatory cost range under Minn. Stat. § 216H.06 – $9 to $34 per short ton of CO_2 emitted – represents one potential price range for allowances (not ERCs).[1] The Company applies the midpoint of this range, $21.50 per ton, as a base assumption in resource planning, and applies the two ends of the range as sensitivities. The MPCA and Minnesota Department of Commerce recently released a request for comments on

[1] April 28, 2014 Order. *In the Matter of Establishing an Updated Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06*. Docket No. E999/CI-07-1199.

the 2016 update of the regulatory cost range, making a preliminary recommendation to retain the range at $9 to $34 per ton.[2]

The Company agreed with the agencies that this range remains reasonable with the information currently available.[3] The Commission's regulatory cost range was first established in 2008, at a time when Congress was contemplating economy-wide, mass-based CO_2 "cap and trade" proposals, and reflected expert predictions of the CO_2 price that might emerge in such markets. While none of these proposals was signed into law, and today power sector CO_2 regulation is proceeding under section 111(d) of the Clean Air Act, as noted above, EPA has provided for market-based compliance mechanisms in both State and Federal Plans. Minnesota and other states in the region appear to be strongly considering this option, so a market-based regulatory cost appears to be a reasonable assumption.

We do not, however, know whether Minnesota's plan will involve allowance or ERC trading, what other states in the region might choose, or how broad or liquid CO_2 credit markets might be. Experience with existing CO_2 markets in the United States and internationally suggests that efficient market design and geographically broader markets lead to lower CO_2 prices, and prices in existing United States CO_2 markets have historically been in the lower end of the Commission's range.[4] However, with CPP State Plans still in such early stages, and actual CPP markets not yet in existence, it seems premature to conclude that prices will be lower than $9 (or higher than $34). For this analysis, we have used the same $9, $21.50, and $34 per ton that we use in Strategist modeling.

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[2] December 3, 2015 Request for Comments. *In the Matter of Establishing an Updated Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06*. Docket No. E999/CI-15-708, Docket No. E999/CI-07-1199. The Agencies recommended shifting the date utilities are required to begin applying the range to 2022, which reflects the first year utilities will face a cost to comply with the CPP.

[3] January 14, 2016 *Comments on Updating the Estimated Cost of Future Carbon Dioxide Regulation under Minn. Stat. § 216H.06*. Docket No. E999/CI-15-708.

[4] For example, $12.73 per metric ton ($11.55 per short ton) in the most recent allowance auction in California, and $7.50 per short ton in the most recent allowance auction in the northeastern states Regional Greenhouse Gas Initiative. Prices in prior auctions were lower. See http://www.arb.ca.gov/cc/capandtrade/auction/auction.htm and http://www.rggi.org/market/co2_auctions/results.

The Commission has no corresponding estimate that could be applied as a price per ERC, and there are no existing rate-based CO_2 markets from which to estimate a price of ERCs.[5]

2. *State Plan Decisions Affecting Company's Allowance Budget*

The size of the Company's allowance budget will depend on many decisions yet to be made in Minnesota's State Plan. Strategist modeling provides a forecast of CO_2 emissions from our CPP-regulated units; however, whether and by how much the allowance budget allocated to the Company (under a mass-based plan) exceeds those emissions will depend on how the plan allocates allowances. Similarly, our overall ERC position (under a rate-based plan) will depend on the activities eligible for ERC crediting.

We here provide analysis of a mass-based plan simply because the Commission's regulatory cost range under Minn. Stat. § 216H.06 provides an allowance price in dollars per ton of CO_2, and we have no comparable basis for predicting a price per ERC. We note that the Company has not yet concluded whether a mass- or rate-based plan is better for our customers.

To estimate our allowance position, we compare projected emissions from CPP-regulated units to the allowance budget that would be allocated to the Company under two hypothetical State Plan scenarios. Both begin with the statewide CO_2 budget for existing units from the CPP, and apply a set of allocation assumptions to derive the share of this budget allocated to the Company.

Scenario 1 assumptions:

- Plan covers existing units only, not new units;
- MPCA demonstrates to EPA that the risk of emission leakage[6] is low in Minnesota, and does not implement allowance set-asides to address leakage;

[5] There are existing markets providing prices for Renewable Energy Credits (RECs) of different types and vintages, and there is some overlap between the types of activities that can generate ERCs and those that can generate RECs. However the overlap is partial, and ERCs and RECs will be separate compliance instruments (ERCs for CPP compliance, RECs for compliance with state renewable energy mandates). Currently low REC prices reflect, among other factors, that relatively cost-effective renewable energy has put many utilities in the situation of having ample RECs for compliance with state renewable energy mandates. However, eventual prices for ERCs will be driven by supply and demand in new CPP markets, which will depend on how many states choose rate-based plans. We have not assumed REC prices provide a proxy for ERC prices.

[6] The CPP defines emission leakage as the incentive to shift generation from affected units regulated under section 111(d) of the Clean Air Act to non-affected units (e.g. new units regulated under section 111(b)).

- Plan includes the Clean Energy Incentive Program (CEIP) allowance set-aside to encourage pre-2022 renewable energy and low-income energy efficiency, and the corresponding matching allowances from EPA;
- Plan includes no other allowance set-asides;
- Plan allocates allowances to affected unit owners based on 2010-2012 generation;[7]
- Plan does not limit the years of allowance allocation to a retired unit;
- The Company earns some allowances back from the CEIP set-aside by implementing eligible activities (wind and solar installed, and low-income energy efficiency implemented, after September 2018).[8]

Scenario 2 assumptions:

- Plan covers existing units only, not new units;
- MPCA adopts EPA's proposed allowance set-asides to address leakage: a set-aside for renewable energy at five percent of the state's allowance budget, and an output-based set-aside for existing natural gas combined cycle units;
- Plan includes the CEIP allowance set-aside to encourage pre-2022 renewable energy and low-income energy efficiency, and the corresponding matching allowances from EPA;
- Plan includes other set-asides, for purposes yet to be determined, totaling an additional 20 percent of the statewide allowance budget;
- Plan allocates allowances to affected unit owners based on 2010-2012 generation;
- Plan allocates no allowances to a retired unit after two years, redirecting these allowances to the renewable energy set-aside;[9] and

[7] We here adopt the default allowance allocation method from EPA's proposed Federal Plan, while noting that EPA leaves the allowance allocation decision to states, and that discussion of the most appropriate allocation basis (generation or emissions, and whether any allowance set-asides are appropriate) is ongoing as of this filing.
[8] Xcel Energy, MPCA and others have urged EPA to shift the eligibility date for the CEIP earlier, making new wind and solar installed, and low-income energy efficiency implemented, after initial plan submittal in September 2016 (rather than after final plan submittal in September 2018) eligible for CEIP allowances or ERCs. Since EPA's decision on this issue is not yet known, this analysis assumes CEIP eligibility as currently proposed.
[9] As proposed by EPA in the proposed Federal Plan. Neither this nor any other allowance allocation provision is binding for an approvable State Plan.

- The Company earns some allowances back from the CEIP, renewable energy, and existing natural gas combined cycle allowance set-asides, but is not assumed to earn any allowances back from other set-asides.

3. *Results*

The difference in the allowances available to monetize on behalf of our customers (after surrendering sufficient allowances to cover our CPP-regulated unit emissions) is significant between the two State Plan scenarios above.

Scenario 1, because it includes no allowance set-asides except the CEIP and does not limit the years of allowance allocation to retired units, results in a larger Company budget and therefore larger compliance buffer. Once the Company surrenders sufficient allowances to cover its CPP-regulated unit emissions each year, there is a remainder of between 1 and 4 million tons per year, totaling about 25 million tons cumulatively over 2022-2030. These allowances are assumed available for sale to the owners of CPP-regulated units in any state that adopts a mass-based plan. At $21.50 per ton, the undiscounted value over 2022-2030 is $540 million ($258 million in net present value terms).

Scenario 2 has significantly more allowance set-asides: for renewable energy (5 percent of the state budget), for existing natural gas combined cycle units, and for other purposes (20 percent of the state budget); in all, set-asides amount to 29-33 percent of the state budget, before accounting for additional allowances redirected from retired units to the renewable energy set-aside. Scenario 2 also discontinues allowance allocation to a retired unit two years after retirement, which significantly reduces the Company's budget. The Company earns some allowances back from the CEIP, renewable energy, and existing NGCC set-asides by implementing those actions, but is assumed to receive no allowances from the other set-asides, which simply redirect allowance value to other entities and purposes. Once the Company surrenders sufficient allowances to cover its CPP-regulated unit emissions each year, there is a deficit in some years and a small remainder in others, and over 2022-2030 a much smaller remainder of 3.5 million tons cumulatively. These allowances are assumed available for sale to the owners of CPP-regulated units in any state that adopts a mass-based plan. At $21.50 per ton, the undiscounted value over 2022-30 is $75 million ($33 million in net present value terms).

At $21.50 per ton, the difference between State Plan scenarios 1 and 2 is an undiscounted value of $465 million over 2022-2030 ($225 million in net present value terms). The value at three different CO_2 allowance prices, corresponding to the Commission's low, midpoint, and high regulatory cost values, is shown below:

Table 1: Value of allowances, in excess of compliance needs, under two State Plan scenarios (hundreds of million dollars, undiscounted, over 2022 to 2030)

Allowance Price	Scenario 1	Scenario 2	Difference
$9/ton	$226	$31	$194
$21.50/ton	$540	$75	$465
$34/ton	$853	$119	$735

The "difference" column in this table essentially represents the value transferred from the Company's customers to other parties, in or out of state, by shifting to a State Plan that sets aside significantly more allowances, and discounts the value of retiring coal units by allocating allowances for only a short time post-retirement.

Since all allowance value is assumed to accrue to the Company's customers, a state plan similar to Scenario 1 would provide around $540 million to help mitigate the rate impacts of transitioning to a lower-carbon energy system. A state plan similar to Scenario 2 would provide $465 million less to mitigate customer cost impacts, and would shift much of this value from our customers to other parties.

4. Rate-Based Compliance

The actions in our Current Preferred Plan would also generate a large number of ERCs if Minnesota adopts a rate-based State Plan. Actions eligible for ERC issuance ultimately depend on the State Plan, but the eligible actions under the CPP include:

- *Renewable energy*: generation starting January 1, 2022 from new facilities placed in service after January 1, 2013. The Company's new wind and solar placed in service after 2012, including projects earlier approved by the Commission, and projects proposed in the Current Preferred Plan, are eligible;
- *Energy efficiency*: electricity savings starting January 1, 2022, from measures placed in service after January 1, 2013, are eligible;
- *Nuclear uprates*: the 71 MW uprate at our Monticello nuclear generating station is eligible, since it was placed in service after 2012;
- *New Canadian hydro*: if the Company executes a new power purchase agreement with a new or uprated hydro facility in Canada, this would be eligible;

- *Affected units*: ERCs generated by natural gas combined cycle units operating below the subcategory rate specified for that year, as well as combined cycle units generating gas-shift ERCs, are eligible;[10]
- *CEIP*: generation and savings in 2020-21 from renewable energy projects that commence construction, and low-income energy efficiency measures placed in service, after final state plan submittal in 2018, including ERCs from the EPA match of 1:1 for renewable energy and 2:1 for low-income energy efficiency.[11]

Greater uncertainty surrounds the ERC eligibility of actions such as distributed generation, repowering on-site of an existing renewable energy facility built before 2012, combined heat and power, etc.

Based on preliminary estimates of the ERCs generated from our proposed actions, we expect the Company would generate more ERCs than needed to bring our regulated units into compliance. These ERCs are assumed available for sale to the owners of CPP-regulated units in any state that adopts a rate-based plan. We have not attempted to estimate a value of excess ERCs, since we have no basis for predicting an ERC price comparable to the available methods for CO_2 allowance prices; however, as with allowances, the value of any excess ERCs accrues to our customers and could be used to reduce the electricity rate impacts of transitioning the Company's generation portfolio to a lower-carbon system.

C. State Plan Positions

The Company has not yet taken a position whether a rate-based or mass-based State Plan is best for our customers, since that decision is dependent on the specifics of each plan. A mass-based plan has advantages in terms of simplicity of administration and compliance, but – as indicated by the two Scenarios above – poses risks of allowance allocation decisions that could significantly increase costs to our customers. A rate-based plan has lower allocation risks, but is significantly more complex to administer as proposed by EPA. We are currently in the process of identifying, in discussion with the MPCA, other utilities, and other stakeholders, areas of agreement for each plan type.

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[10] Gas-shift ERCs are a special type of ERCs awarded to combined cycle units that operate above their unit-specific 2012 baseline level of operation. Gas-shift ERCs may only be used for compliance by coal units.
[11] As mentioned above, we are not assuming for this analysis that EPA moves the CEIP eligibility dates earlier, nor that MPCA submits its State Plan earlier than the September 2018 deadline.

If MPCA selects a mass-based plan, we believe this plan should:

- Enable interstate trading through a "trading-ready" approach;
- Cover existing affected coal and natural gas combined cycle units only, not new units;[12]
- Demonstrate to EPA that the risk of emission leakage is low in Minnesota, using state Renewable Energy Standard and Conservation Improvement Program mandates, integrated resource plans, etc.;
- Allocate allowances to the owners of affected units on behalf of their customers. Allowance auctions serve no policy objective in a fully regulated state like Minnesota, merely increasing costs to customers without achieving additional CO_2 reductions;
- Allocate allowances to an affected unit that retires after 2012 for the duration of the CPP program. The analysis above illustrates the significant amount of value transferred from our customers to other parties, in and out of state, by redirecting these allowances;
- Not assign a "shelf life" to previously issued allowances;
- Allocate allowances among affected unit owners based on 2010-12 operations;[13]
- Minimize allowance set-asides, which utilities agree are likely to increase costs, except for the Clean Energy Incentive Program (CEIP) set-aside;[14]
- Require that the state allowance budget be used only for purposes of compliance, and that allowances may not be retired for other purposes;
- Include, but explore the ability to improve, the CEIP.

If the State Plan significantly deviates from the above principles, a rate-based plan may be better for our customers. If MPCA selects a rate-based plan, we believe this plan should:

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[12] The Clean Air Act defines existing units as those constructed prior to, and new units as those constructed subsequent to, January 8, 2014 – the date of EPA's release of the proposed New Source Performance Standard under Clean Air Act section 111(b).

[13] For example, allowances could be allocated based on 2010-12 generation (as proposed by EPA in the proposed Federal Plan), 2010-12 emissions, or another basis. EPA leaves the allocation method to states' discretion. The most appropriate method (both whether based on generation or emissions, and whether any allowance set-asides are appropriate) remains under discussion as of this filing. Whatever the method, the plan should incorporate EPA's correction in the final CPP for Sherburne County Unit 3, replacing 2012 data with typical-year generation or emissions.

[14] Whether any targeted set-asides are appropriate likewise remains under discussion as of this filing. In general, utilities agree allowance set-asides should be minimal and used with caution, since each set-aside reduces the budget allocated to utility customers and thus increases their costs.

- Enable interstate trading through a "trading-ready" approach;
- Use the subcategory-specific emission performance rates for fossil fuel-fired steam generating units and stationary combustion turbines;
- Leverage Minnesota's robust renewable energy and energy efficiency policies to streamline EPA's evaluation, monitoring and verification requirements for ERC crediting;
- Make the broadest possible set of zero-carbon actions eligible to earn ERCs, including but not limited to:
  - renewable energy (all types defined as renewable in state statute),
  - renewable energy uprates and repowering,
  - distributed generation,
  - end-use energy efficiency,
  - demand response and demand-side management,
  - nuclear uprates,
  - Canadian hydro,
  - existing natural gas combined cycle operating below the applicable subcategory rate or generating gas-shift ERCs, and
  - transmission and distribution efficiency improvements;
- Not assign a "shelf life" to ERCs;
- Award ERCs to existing (pre-2012) renewable energy facilities that are significantly repowered on the same site after 2012;
- Include, but explore the ability to improve, the CEIP.

Certificate of Service

I, SaGonna Thompson, 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 electronic filing.

Docket No. E002/RP-15-21

Dated this 29th day of January 2016

/s/

SaGonna Thompson
Regulatory Administrator

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_Official
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_15-21_Official
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_Official
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_Official
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_Official
James J.	Bertrand	james.bertrand@stinson.com	Stinson Leonard Street LLP	150 South Fifth Street, Suite 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
Michael J.	Bull	mbull@mncee.org	Center for Energy and Environment	212 Third Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_Official
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_Official
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_Official
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_15-21_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Leigh	Currie	lcurrie@mncenter.org	Minnesota Center for Environmental Advocacy	26 E. Exchange St., Suite 206 St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_15-21_Official
Jeffrey A.	Daugherty	jeffrey.daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
Dustin	Denison	dustin@appliedenergyinnovations.org	Applied Energy Innovations	4000 Minnehaha Ave S Minneapolis, MN 55406	Electronic Service	No	OFF_SL_15-21_Official
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_Official
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_Official
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	1313 5th St SE #303 Minneapolis, MN 55414	Electronic Service	No	OFF_SL_15-21_Official
Emma	Fazio	emma.fazio@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
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_Official
Mike	Fiterman	mikefiterman@libertydiversified.com	Liberty Diversified International	5600 N Highway 169 Minneapolis, MN 55428-3096	Electronic Service	No	OFF_SL_15-21_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
John	Flumerfelt	jflumerfelt@calpine.com	CalpineCorporation	500 Delaware Ave. Wilmington, DE 19801	Electronic Service	No	OFF_SL_15-21_Official
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_Official
J Drake	Hamilton	hamilton@fresh-energy.org	Fresh Energy	408 St Peter St Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_Official
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_15-21_Official
Patrick	Hentges		City Of Mankato	P.O. Box 3368 Mankato, MN 560023368	Paper Service	No	OFF_SL_15-21_Official
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_Official
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	OFF_SL_15-21_Official
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_Official
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_15-21_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Mark J.	Kaufman	mkaufman@ibewlocal949.org	IBEW Local Union 949	12908 Nicollet Avenue South Burnsville, MN 55337	Electronic Service	No	OFF_SL_15-21_Official
Jerome	Kleis	N/A		12060 Sherburne Ave Becker City Hall Becker, MN 55308-4694	Paper Service	No	OFF_SL_15-21_Official
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_Official
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_15-21_Official
Mara	Koeller	mara.n.koeller@xcelenergy.com	Xcel Energy	414 Nicollet Mall 5th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_15-21_Official
Frank	Kohlasch	frank.kohlasch@state.mn.us	MN Pollution Control Agency	520 Lafayette Rd N. St. Paul, MN 55155	Electronic Service	No	OFF_SL_15-21_Official
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_Official
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_15-21_Official
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_Official
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_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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_Official
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	Yes	OFF_SL_15-21_Official
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_15-21_Official
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_Official
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_Official
Brian	Meloy	brian.meloy@stinson.com	Stinson,Leonard, Street LLP	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
Erin	Mittag	emittag@mncenter.org	Minnesota Center for Environmental Advocacy	26 E Exchange Street, Suite 206 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_15-21_Official
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_15-21_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Alan	Muller	alan@greendel.org	Energy & Environmental Consulting	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_15-21_Official
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_Official
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_Official
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_15-21_Official
Gayle	Prest	gayle.prest@minneapolismn.gov	City of Mpls Sustainability	350 South 5th St, #315 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_15-21_Official
Greg	Pruszinske	gpruszinske@ci.becker.mn.us	City of Becker	Box 250 12060 Sherburne Ave Becker, Minnesota 55308	Electronic Service	No	OFF_SL_15-21_Official
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	Yes	OFF_SL_15-21_Official
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_Official
Larry L.	Schedin	Larry@LLSResources.com	LLS Resources, LLC	12 S 6th St Ste 1137 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_15-21_Official
Inga	Schuchard	ischuchard@larkinhoffman.com	Larkin Hoffman	8300 Norman Center Drive Suite 1000 Minneapolis, MN 55437	Electronic Service	No	OFF_SL_15-21_Official

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_Official
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_Official
Joshua	Smith	joshua.smith@sierraclub.org		85 Second St FL 2 San Francisco, California 94105	Electronic Service	Yes	OFF_SL_15-21_Official
Beth H.	Soholt	bsoholt@windonthewires.org	Wind on the Wires	570 Asbury Street Suite 201 St. Paul, MN 55104	Electronic Service	Yes	OFF_SL_15-21_Official
Anna	Sommer	anna@sommerenergy.com	Sommer Energy LLC	PO Box 766 Grand Canyon, AZ 86023	Electronic Service	Yes	OFF_SL_15-21_Official
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_Official
Mark	Spurr	mspurr@fvbenergy.com	International District Energy Association	222 South Ninth St., Suite 825 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_15-21_Official
Byron E.	Starns	byron.starns@stinson.com	Stinson Leonard Street LLP	150 South 5th Street Suite 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
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_Official
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_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
SaGonna	Thompson	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_15-21_Official
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_Official
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_Official
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_Official
Cam	Winton	cwinton@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_15-21_Official
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_Official
Jonathan G.	Zierdt	N/A	Greater Mankato Growth	1961 Premier Dr Ste 100 Mankato, MN 56001	Paper Service	No	OFF_SL_15-21_Official
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_Official

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
SOUTH DAKOTA ELECTRIC RATE BOOK - SDPUC NO. 2

PRELIMINARY STATEMENT

Section No.	3
1st Revised Sheet No.	1
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SUBDIVISION 1 INDEX OF COMPANY'S SERVICE AREA

Northern States Power Company supplies electric service at retail in the State of South Dakota in the incorporated municipalities, unincorporated named communities and hamlets, townships and counties listed below.

COMMUNITIES	
Alexandria	
Artesian	
Baltic	
Benton Township	N
Brandon	N
Brandon Township	N
Bridgewater	
Bridgewater Township	N
Canistota	
Canova	
Canton	
Canton Township	N
Carthage	
Centerville	
Centerville Township	N
Chancellor	
Crooks	
Delapre Township	N
Dell Rapids	
Dell Rapids Township	N
Dolton	
Dolton Township	N
Ellis	
Emery	
Fedora (U)	

COMMUNITIES	
Forestburg (U)	
Fulton	
Garretson	
Germantown Township	N
Grant Township	N
Hanson County	
Harrisburg	
Howard Township	ND
La Valley Township	N
Lake County	
Lennox	
Lincoln County	
Logan Township	N
Lyons Township	N
Mapleton Township	N
Marion	
McCook County	
Miner County	
Minnehaha County	
Monroe	
Monroe Township	N
Moody County	
Palisade Township	N
Perry Township	N

COMMUNITIES	
Ramona	
Renner (U)	
Roswell	D
Salem	
Sanborn County	
Sherman	
Sioux Falls	
Sioux Falls Township	N
Split Rock Township	N
Spring Valley Township	N
Springdale Township	N
Sverdrup Township	N
Tea	
Turner County	
Union Township	ND
Valley Springs Township	N
Vilas	
Wall Lake Township	N
Wayne Township	N
Wellington Township	N
Winfred (U)	
Worthing	

(U) Denotes unincorporated community

(Continued on Sheet No. 3-2)