Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

May 1, 2023

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: PETITION
2024 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES
DOCKET NO. E002/AA-23-153

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Petition for approval of our Annual Fuel Forecast in support of proposed monthly fuel cost charges for the months of January-December 2024.

Please note that portions of our Petition and attachments are marked as "Not Public." Certain data is considered to be "not public data" pursuant to Minn. Stat. §13.02, Subd.9, and is "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as this data derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service lists. Please contact Rebecca Eilers at 612-330-5570 or rebecca.d.eilers@xcelenergy.com or me at 612-330-7681 or lisa.r.peterson@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

LISA R. PETERSON
DIRECTOR, REGULATORY PRICING & ANALYSIS

Enclosures
cc: Service Lists

REQUIRED INFORMATION

I. SUMMARY OF FILING

A one-paragraph summary is attached to this filing pursuant to Minn. R. 7829.1300, subp. 1.

II. SERVICE ON OTHER PARTIES

Pursuant to to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission. Pursuant to Minn. R. 7829.1300, subp. 2, the Company has served a copy of this filing on the Department of Commerce and the Office of the Attorney General. Pursuant to Minn. R. 7825.2840, we have provided notice of the availability of the report to all intervenors in the Company's two previous general rate cases.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, Xcel Energy provides the following information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company, doing business as
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Ian Dobson
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401-8th Floor
Minneapolis, MN 55401
(612) 370-3578

C. Date of Filing and Proposed Effective Date of Rates

The date of this filing is May 1, 2023. The Company's Petition proposes different monthly fuel cost charges for each month of the year 2024, and we propose to implement the monthly rate changes on the first day of each month for the 12 months beginning January 1, 2024. In order to provide customers 30 days' notice of the January 1, 2024 rate, we request that an Order be issued in this docket by November 30, 2023 as established in Appendix A of the June 12, 2019 Order in Docket No. E999/CI-03-802.

D. Statutes Controlling Schedule for Processing the Filing

The schedule for this filing is controlled by Commission Order rather than a particular statute or rule. The Commission's June 12, 2019 Order in Docket No. E999/CI-03-802 approved a procedural schedule for the initial filing, review, and approval of the Annual Fuel Forecast. Under this schedule, Comments are due on June 30, 2023, Reply Comments are due on July 30, 2023 and Response Comments are due on August 30, 2023. A Commission Order is expected by November 30, 2023. The Company plans to update inputs with more current information in its Reply Comments.

E. Utility Employee Responsible for Filing

Lisa Peterson
Director, Regulatory Pricing & Analysis
Xcel Energy
414 Nicollet Mall, 401-7th Floor
Minneapolis, MN 55401
612-330-7681

IV. MISCELLANEOUS INFORMATION

Pursuant to Minn. R. 7829.0700, Xcel Energy requests that the following persons be placed on the Commission's official service list for this matter:

Ian Dobson
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401-8th Floor
Minneapolis, MN 55401
ian.m.dobson@xcelenergy.com

Christine Schwartz
Regulatory Administrator
Xcel Energy
414 Nicollet Mall, 401-7th Floor
Minneapolis, MN 55401
regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to Ms. Schwartz at the Regulatory Records email address above.

PUBLIC DOCUMENT
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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2024 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-23-153

PETITION

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Petition requesting approval of the 2024 Annual Fuel Forecast and resulting proposed monthly fuel cost charges for the months of January-December 2024. This Petition is submitted in compliance with the various Orders issued in Docket No. E999/CI-03-802 which implemented Fuel Clause Reform[1] and with the Commission's November 14, 2019 Order in our 2020 Fuel Forecast proceeding in Docket No. E002/AA-19-293.

We request recovery of approximately $1,030 million in total Fuel Clause costs for the Minnesota jurisdiction in 2024, or approximately $38.38/MWh. This is a decrease of approximately $39.0 million compared to Fuel Clause costs authorized by the Commission for 2023. We discuss the primary drivers for these costs later in this Petition.

This is the Company's fifth forecast filing in connection with the Fuel Clause Reform pilot process.[2] We note that the Commission approved this process as a three-year pilot program. As specified in the December 12, 2018 Order in Docket No. E999/CI-03-802, we will meet with other parties to discuss what should be included in the required lessons learned report and make a filing in 2023. We look forward to

[1] Orders dated December 17, 2017, December 12, 2018, and June 12, 2019.
[2] The most recent forecast, the 2023 Fuel Forecast, was approved by the Commission's December 5, 2023 Order in Docket No. E002/AA-22-179.

providing constructive feedback regarding potential improvements to this process that can assist us in providing customers with timely price signals.

As discussed below, this Petition requests approval to implement specific fuel clause rates by month and customer class throughout 2024. These rates are based on forecasts developed by the Company using the PLEXOS software, which models the Company's system load and generating unit characteristics, along with fuel commodity prices and electric market prices. The forecast is summarized in Part A, Attachments 1 through 4, and the detailed output of the model is provided as Part F, Workpaper 2. We then take the monthly forecasts developed by this modeling and use the results to create the monthly Fuel Clause rates by customer class for which we seek approval. Part A, Attachment 1 presents the rate calculations by month and by class as we propose to implement them.

The data and calculations presented in connection with this Petition are necessarily complex in order to provide accurate pricing. We are available to meet with the Department to walk through our data and calculations in detail, and we are prepared to meet with other stakeholders to answer questions other parties may have about our process and the information in this filing.

As set out in the compliance matrix included with this Petition as Part C, Attachment 1, this Petition and its attachments include all required information from the December 17, 2017, and December 12, 2018, and June 12, 2019 Orders in Docket No. E999/CI-03-802, as well as the November 14, 2019 Order in Docket No. E002/AA-19-293. The remainder of this Petition discusses our process for forecasting fuel costs and Fuel Clause rates in 2024. Specifically, we discuss the following:

- The background leading to the Fuel Clause reform process, our proposed fuel cost charges for 2024, and proposed tariff revision reflecting the monthly fuel cost charges;
- The inputs and drivers in the Company's forecasts underlying our proposed fuel cost charges;
- The calculation of the specific monthly fuel cost charges based on the Company's forecast; and
- The efforts the Company is undertaking to manage price volatility and risk in our fuel and purchased power costs.

A Table of Contents outlining the attachments and workpapers we are providing in support of our request is included as an addendum to this Petition.

I. DESCRIPTION AND PURPOSE OF FILING

A. Background

On December 19, 2017, the Commission issued its ORDER APPROVING NEW ANNUAL FUEL CLAUSE ADJUSTMENT REQUIREMENTS AND SETTING FILING REQUIREMENTS in Docket No. E999/CI-03-802 (December 19 Order) which requires a utility's fuel rates to be set in a rate case or an annual fuel clause adjustment filing unless a utility can show a significant unforeseen impact. The Order specifies that these filings should include complete documentation supporting the proposed fuel rates, including information on Power Purchase Agreements (PPAs), estimates of costs for each type of fuel, and the proportion of each type of fuel, along with a complete description of any model used to develop the proposed $/MWh fuel rates, including but not limited to the identification and justification of the inputs and formulas used for all fuel types, and fully documented sales forecasts.

The Commission's December 12, 2018 Order in the same docket (December 12 Order) established January 1, 2020 as the implementation date for Fuel Clause Reform and also ordered that the forecast year be a calendar year. Each utility is required to file its Annual Fuel Forecast Petition in a separate docket.

In the June 12, 2019 Order, the Commission approved the disposition of reporting items from the Annual Automatic Adjustment of Charges reports (AAA) under the fuel clause mechanism in place at the time and set a procedural schedule for the initial filing, review and approval of the Annual Fuel Forecast process, which was agreed upon by the parties to the docket. Under this agreed upon schedule, Comments are due on June 30, 2023, Reply Comments are due on July 30, 2023, and Response Comments are due on August 30, 2023. A Commission Order is expected by November 30, 2023 to allow utilities to provide customers notice of the new rates 30 days before the first rate is implemented.

B. Summary of Proposed Rates and Customer Notification

Tables 1 and 2 below show the specific rates we request be implemented by month and by customer class as determined by our fuel forecast for 2024.

Table 1: Proposed 2024 Monthly Fuel Clause Rates by Customer Class ($/kWh)

Month	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
January	$0.03388	$0.03430	$0.03324	$0.04154	$0.02721	$0.02658
February	$0.03637	$0.03683	$0.03568	$0.04460	$0.02920	$0.02852
March	$0.03937	$0.03987	$0.03863	$0.04829	$0.03161	$0.03088
April	$0.04222	$0.04275	$0.04142	$0.05178	$0.03390	$0.03311
May	$0.04512	$0.04569	$0.04427	$0.05533	$0.03623	$0.03539
June	$0.04233	$0.04287	$0.04153	$0.05192	$0.03399	$0.03320
July	$0.04253	$0.04307	$0.04172	$0.05218	$0.03412	$0.03333
August	$0.04218	$0.04271	$0.04138	$0.05175	$0.03385	$0.03307
September	$0.03899	$0.03948	$0.03825	$0.04782	$0.03129	$0.03057
October	$0.03806	$0.03854	$0.03734	$0.04668	$0.03055	$0.02984
November	$0.03505	$0.03549	$0.03438	$0.04299	$0.02813	$0.02748
December	$0.03249	$0.03290	$0.03188	$0.03985	$0.02609	$0.02548

Table 2: Proposed 2024 Monthly Fuel Clause Rates for C&I General Time of Use Service Pilot ($/kWh)

Month	Commercial & Industrial General TOU Service Pilot		
	Demand		
	Peak	Base	Off-Peak
January	$0.04197	$0.03564	$0.01863
February	$0.04507	$0.03826	$0.01998
March	$0.04879	$0.04142	$0.02162
April	$0.05232	$0.04442	$0.02319
May	$0.05591	$0.04747	$0.02480
June	$0.05246	$0.04454	$0.02325
July	$0.05273	$0.04475	$0.02331
August	$0.05229	$0.04438	$0.02314
September	$0.04832	$0.04102	$0.02140
October	$0.04717	$0.04004	$0.02090
November	$0.04344	$0.03687	$0.01924
December	$0.04027	$0.03419	$0.01785

We will update the Company web site with the full year of monthly fuel cost charges by December 1, 2023, or upon approval by the Commission if approval is not received prior to December 1. The rates will be presented at the following link: https://www.xcelenergy.com/company/rates_and_regulations/rates/rate_riders. We do not propose any additional customer notice.

C. Revised Tariff Sheet

We provide as Part A, Attachment 5 redline and clean revisions to the Fuel Clause Rider tariff, Sheet No. 5-91.1, reflecting the monthly fuel cost charges we propose to implement. We will update the tariff sheet to reflect the actual monthly fuel cost charges to be implemented based on the Commission's decisions in this proceeding and will provide an updated final tariff sheet in a compliance filing within 10 days after the Order is received.

II. 2024 FORECAST FUEL AND PURCHASED ENERGY COSTS

The Company uses the PLEXOS software to model the NSP power supply system and forecast costs for fuel and purchased energy. As discussed below, the resultant forecast forms the basis of the rates projected for 2024 shown in Tables 1 and 2 above. PLEXOS has been used by the Company since 2015 to forecast fuel and purchased energy costs for all Xcel Energy operating companies.

PLEXOS uses mathematical programming and optimization techniques for power generation modeling and simulation. For forecast purposes, the unit commitment and economic dispatch logic of PLEXOS commits and dispatches NSP System generation resources, contractual assets, and electric markets to balance system energy demand and meet reserve requirements, while enforcing all generating resource and operation constraints at the least system cost. The PLEXOS simulation inputs include variables such as the NSP System load forecast, generating unit characteristics and operating parameters for owned resources as well as generating resources under PPAs, fuel commodity prices and electric market prices. The PLEXOS simulation is an hourly simulation such that several key inputs, such as NSP System load and wind patterns, are input with hourly profiles. Key input assumptions used to develop the PLEXOS forecast are discussed below, and key inputs are shown in Part F, Workpaper 1. Additionally, we discuss the drivers of the changes in costs for the 2024 test year and how we used the forecast to determine the rates shown above in Tables 1 and 2. More detail about the PLEXOS software modeling is described in Part B, Attachment 1.

A. 2024 Forecast Key Inputs

i. NSP System Load

The objective of the PLEXOS simulation is to commit and dispatch resources to meet the hourly load requirement at the lowest cost. The PLEXOS simulation determines the hourly load requirement based on the most recent forecast of monthly energy and monthly peak demands at the source developed by the Company's Sales Energy & Demand Forecasting group. Part B, Attachment 13 describes the forecasting process in detail. A summary of the monthly sales forecast is shown in Part G, Workpaper 1. The monthly load forecast is then converted into an hourly forecast by PLEXOS based on a typical hourly shape for the NSP system load.

ii. Company-Owned Hydro Generation

Inputs for NSP-owned hydro generation in the PLEXOS model are based on a 30-year annual historical average of hydro generation results for NSP System plants. PLEXOS then creates an hourly generation forecast, which converts the annual historical average to an hourly generation profile based on historic hourly capacity factors. There is no fuel price input for hydro generation in the model because hydro generation does not require any fuel purchases. See Part G, Workpapers 2.

iii. Company-Owned Wind Generation

NSP-owned wind generation inputs to the PLEXOS model use individual hourly profiles for each NSP-owned project. Profiles of hourly renewable generation for individual Midcontinent Independent System Operator (MISO) Commercial Pricing Nodes (CP Nodes) are developed based on historic weather data and exclude any prior historical curtailments. For new projects that do not yet have an annual generation profile, the profiles are based on turbine technology, plant design, and localized weather data. New projects are further adjusted to reflect warranty, preventative maintenance, daily faults, and other issues common with new wind farms in their first years of operation. Company-owned projects are modeled as curtailable projects since they can be curtailed by MISO. Curtailment of owned wind projects is forecast by the PLEXOS simulation. A white paper describing the wind profile forecast process in detail is provided with this filing as Part B, Attachment 10. There is no fuel price input for wind generation in the model because wind generation does not require any fuel purchases.

iv. Company-Owned Coal Generation

Each NSP-owned coal unit is modeled in the PLEXOS simulation. Key modeling parameters such as operating capacity and heat rate are provided by the Company's Energy Supply business unit based on capabilities of the individual plants. Planned maintenance is input to the model based on the current overhaul schedule, which is included with the filing as Part B, Attachment 5. Forced outage rates are input for each unit and determined based on historical Generation Availability Data System (GADS) data and expected conditions of the units going forward, including managed decline as plants near retirement. Supporting calculations for forced outage rates are summarized in Part B, Attachment 6 and shown in detail in Part G, Workpaper 10.

Estimated replacement power costs for planned and forced outages are summarized in Part B, Attachment 7.

Coal prices are forecast based on coal purchases under contract and rail contracts in effect at the time of filing. Any coal requirements that are not under contract are forecast based on market prices. Supporting coal and rail pricing is provided with the filing as Part F, Workpaper 3. More detail on contracts, fuel procurement, and fuel supply is available in Part D, Attachments 1, 3, 4, 6 and 8. See also Part B, Attachments 2 and 3 for detailed information on fossil fuel costs and coal burn expenses.

Seasonal operations are not assumed in this initial filing following suspension of the practice due to feedback from the MISO market monitor in 2022. Therefore all coal units, with the exception of Sherco 2 which is planned to retire in 2023, are assumed available to operate year-round for 2024. In addition, the 2024 filing assumes that the EPA will publish its proposed "good neighbor" rule to limit NOx emissions for NSP plants during the ozone season in 2023 which runs from May 1, 2023 through September 30, 2023. The proposal, if enacted for 2024, may require NSP to either purchase NOx allowances to allow generation and emissions beyond proposed limits or to limit operation at NSP coal plants to remain within emission limits in the proposal. We plan to monitor both of these developments and update our modeling assumptions with the best available information in our July Reply Comments.

v. Company-Owned Wood/RDF Generation

Each NSP-owned wood/refuse derived fuel (RDF) unit is modeled in the PLEXOS simulation. Key modeling parameters such as operating capacity and heat rate are provided by the Company's Energy Supply business unit based on capabilities of the individual plants. Planned maintenance is input to the model based on the current overhaul schedule, which is included with the filing as Part B, Attachment 5. Forced outage rates are input for each plant and determined based on historical performance of the plants. Wood and RDF prices are forecast based on existing contracts as shown in Part D, Attachment 5. More detail on fuel procurement and costs is available in Part D, Attachments 1 and 6.

vi. Company-Owned Natural Gas Generation

Each NSP-owned natural gas unit is modeled in the PLEXOS simulation. Key modeling parameters such as operating capacity and heat rate are provided by the Company's Energy Supply business unit based on capabilities of the individual plants. Planned maintenance is input to the model based on the current overhaul schedule, which is included with the filing as Part B, Attachment 5. Forced outage rates are input for each unit and determined based on historical GADS data and expected conditions of the units going forward. For peaking plants, the model uses the MISO calculation of each unit's Equivalent Forced Outage Rate – Demand (eFORd) based on three years of history. Supporting calculations for forced outage rates are summarized in Part B, Attachment 6 and shown in detail in Part G, Workpaper 9. Estimated costs for planned and forced outages are summarized in Part B, Attachment 7. Natural gas fuel prices are based on New York Mercantile Exchange (NYMEX) futures prices for natural gas at the Ventura hub. Costs for transport of natural gas to each specific plant are based on the Company's transport and delivery contracts in place at the time of filing. Monthly Ventura prices assumed in the filing as well as transport rates and supporting detail on the gas transport contracts for each plant are provided with the filing as Part F, Workpaper 4.

vii. Company-Owned Nuclear Generation

Each NSP-owned nuclear unit is modeled in the PLEXOS simulation. Modeling parameters include monthly operating capacity based on the capability of each individual unit. Planned maintenance is input to the model based on the current overhaul schedule, which is included with the filing as Part B, Attachment 5. Forced outage rates are input for each unit and determined based on historical GADS data and expected conditions of the units going forward. Supporting calculations for forced outage rates are summarized in Part B, Attachment 6 and shown in detail in Part G, Workpaper 9. Estimated costs for planned and forced outages are summarized in Part B, Attachment 7. Nuclear fuel price is based on the Company's existing nuclear fuel contracts. Supporting nuclear fuel pricing is provided with the filing as Part B, Attachment 4 and Part D, Attachment 2. More detail on fuel supply is available in Part D, Attachment 8.

viii. Purchased Natural Gas Generation

Each natural gas PPA is modeled in the PLEXOS simulation. Key modeling parameters such as operating capacity and heat rate are determined based on capabilities of the individual plants or according to terms specified in the PPA. Planned maintenance is input to the model based on the overhaul schedule provided by the PPA counterparty. Forced outage rates are input for each unit and based on the MISO calculation of each unit's eFORd based on three years of history. Natural gas fuel prices are forecast based on NYMEX futures prices for natural gas at the Ventura hub. Costs for transport of natural gas to each specific plant are based on transport and delivery contracts in place at the time of filing. Monthly Ventura prices assumed in the filing as well as transport rates and supporting detail on the gas transport contracts for each plant are provided with the filing as Part F, Workpaper 4.

ix. Purchased Solar Generation

Each solar PPA is modeled in the PLEXOS simulation with hourly profiles for each project. These profiles are based on historical results from projects with operational data. A white paper describing the solar profile forecast process in detail is provided with this filing as Part B, Attachment 10. The price for each solar PPA is based on the terms of each contract.

The Solar*Rewards Community program is modeled in the PLEXOS simulation and includes expectations of future growth based on current applications for gardens seeking to participate in the program.[3] To forecast 2024 capacity for community solar projects, we identify current projects to anticipate in-service dates and estimate project completion (in capacity) by month and year. We also forecast additional applications based on a historical average. This helps account for our future pipeline of projects. Capacity assumptions are then modeled in PLEXOS to determine MWh and average dollars per kWh. The program is modeled as one entity within PLEXOS rather than individually by garden in consideration of simulation run times. The assumed price for the program is a weighted rate based on an escalation of the historical Applicable Retail Rate (ARR) and the rates of different vintages of Value of Solar (VOS). Projected prices for future projects are calculated based on VOS vintage and anticipated completion date. The market cost of energy from the solar gardens generation is determined based on the assumed hourly Locational Marginal Price (LMP) in the simulation. This cost is shared with all jurisdictions in the NSP system. The cost of the program above market is direct assigned to Minnesota customers. Supporting documentation for solar gardens assumptions are included with this filing as Part B, Attachment 12 and Part G, Workpapers 6 and 7.

x. Purchased Wind Generation

Purchased wind modeled in the PLEXOS simulation use hourly profiles for each individual project. Profiles of hourly renewable generation for individual MISO CP Nodes are developed based on historic weather data and exclude any prior historical curtailments. For new projects that do not yet have an annual generation profile, the profiles are based on turbine technology, plant design, and localized weather data. A white paper describing the wind profile forecast process in detail is provided with this filing as Part B, Attachment 10. Projects that MISO is allowed to curtail are modeled

[3] Recovery was approved by Commission Order on September 17, 2014 in Docket No. E002/M-13-867.

as curtailable projects. Projects for which curtailment is not allowed are modeled as non-curtailable projects. The price for each wind PPA is based on the terms of each contract. PPA pricing as modeled in the forecast is contained in Part B, Attachment 11. Curtailment cost supporting calculations have been included with the filing in Part G, Attachment 8.

xi. Purchased Generation - Other

PPAs that do not fit within one of the prior three categories (primarily small hydro PPAs, the remaining biomass PPA, and the PPA with Manitoba Hydro) are modeled based on historical generation (for the small hydro PPAs) or according to their contract terms (for the biomass and Manitoba Hydro PPAs). Price is determined based on contract terms or based on historical prices with assumed escalation. Where applicable, supporting calculations have been included with the filing in Part G, Workpapers 3 and 4.

xii. Market Purchases and Sales

When solving to meet NSP System load, the PLEXOS simulation can purchase energy from a simulated MISO market if that source of supply results in lower cost than utilization of one of the NSP system dispatchable resources. The simulation can make this decision hourly within the constraints of the modeled system. In addition, the PLEXOS model forecasts monthly intersystem sales opportunities of excess generation after system native requirements are fulfilled. This is done through an hourly dispatch simulation based on projected hourly market prices representing LMP for the NSP system. The forecasted sales revenue generated from the asset-based sales results in a reduction to system fuel costs, and is shown in Part A, Attachment 1. Forecast asset-based margins for 2024 are **[PROTECTED DATA BEGINS** *$102 million* **PROTECTED DATA ENDS]** and are reflected in the Net System Costs shown at line 35 of Part A, Attachment 1, page 1 of 3. Asset-based margins are the difference between asset-based Sales Revenues shown at line 29 less the underlying generation fuel costs incurred to make the asset-based sales which are part of the total fuel costs shown at line 27. A white paper that describes how the hourly prices are developed is included with the filing as Part B, Attachment 8.

xiii. Other FCA Costs

There are other costs that flow through the fuel clause adjustment (FCA) that are not part of the PLEXOS simulation. These cost categories generally do not impact the PLEXOS commit and dispatch algorithm and therefore can be included outside the simulation. This section lists these costs with a brief description of what they represent.

- Biomass PPA termination costs are included in the filing according to the terms of the termination agreements. Supporting documentation for the costs is included in Part G, Workpapers 5.
    - Benson Power LLC – Early termination of agreement covering the purchase of generation from poultry litter and wood fueled biomass facility.[4] Per the Commission's November 14, 2019 Order in Docket No. E002/AA-19-293, we have applied a 9.06 percent ROE to the Benson termination cost calculation.
- Certain MISO market charges and revenues are not modeled in PLEXOS. This includes costs/revenues associated with transmission congestion, financial transmission rights (FTRs), incremental transmission losses, revenue sufficiency guarantee (RSG), revenue neutrality uplift (RNU) and ancillary services. The cost included in the filing is based on historical actual costs and revenues observed for these MISO charge types. A summary of MISO charges included in the 2024 forecast is provided as Part B, Attachment 9, and a spreadsheet detailing the historical data and the calculation of the forecast is included as Part F, Workpaper 5. The net MISO Day 2 and Day 3 costs and revenues for the 2024 forecast are **[PROTECTED DATA BEGINS**
PROTECTED DATA ENDS] as shown on Part B, Attachment 9.
- Gas demand and storage costs are costs associated with reserving gas delivery capacity and gas storage. The costs are based on contract terms for the capacity and storage contracts. Supporting detail for the contract terms and resultant costs are included in the filing in Part F, Workpaper 4.
- Rail car lease and maintenance costs include estimated lease, maintenance and tax costs associated with coal delivery to the King plant. The costs are based on historical amounts per "ton mile" (round trip from King to the source) multiplied by the forecast coal offtake (in tons). See Part F, Workpaper 3.

xiv. FCA Exclusions

PPAs that serve the Renewable*Connect program are included in the PLEXOS model.[5] The Renewable*Connect program uses a pool of resources that includes

[4] Recovery was approved by Commission Order on January 23, 2018 in Docket No. E002/M-17-530.
[5] Recovery of the Renewable*Connect Pilot Program was approved by Commission Order on February 27, 2017 in Docket No. E002/M-15-985. Recovery of the Renewable*Connect expansion was approved by Commission Order on August 12, 2019 in Docket No. E002/M-19-33.

projects that have been serving Windsource, in addition to several new projects. Because costs for these programs are covered by specific fees paid by subscribers to the programs, an adjustment is made to remove the PPA costs related to those programs from the PLEXOS model. Relatedly, sales to these program participants are removed from Minnesota retail sales used in determining the FCA rate for Minnesota customers. Based on the current forecast, we have not shown separate data for Windsource resources and subscribers because we expect the Windsource program to close and be transitioned to Renewable*Connect during 2023.[6] Support for the Renewable*Connect forecast is found in Part G, Workpaper 10.

xv. Future Model Updates

As noted in Table 1 of the March 1, 2019 Joint Comments filed in Docket No. E999/CI-03-802 which outlines the Procedural Schedule Dates for Fuel Clause Reform implementation, utilities will update their forecast inputs in July Reply Comments. The Company anticipates updating the following items, but will also update additional inputs if there are substantive changes:

- Natural Gas Prices,
- LMP,
- Fuel Oil,
- Gas transport costs,
- Coal prices (including diesel, rail, spot and contracts),
- MISO costs,
- Company-owned resource inputs,
- other PPA changes and approvals, and
- other inputs, as necessary, that materially impact costs.

B. Test Year Drivers

Total FCA costs for the Minnesota jurisdiction are forecast to decrease by $39 million from FCA costs authorized by the Commission for 2023. Table 3 compares costs for several key categories at the NSP system level and the total impact to the Minnesota jurisdiction. Costs authorized for 2023 are shown in column A and costs forecast for the initial 2024 filing are shown in column B.

[6] The transition of Windsource customers to Renewable*Connect will begin upon Commission approval of final program pricing filed in Docket No. E002/M-21-222 on December 22, 2022. Comment periods have concluded and the matter is pending a Commission hearing.

Table 3: Fuel and Purchased Power Cost Comparisons ($000)

	A		B		B - A
	2023		2024		2024
	Authorized(1)		Filing		Change
	[PROTECTED DATA BEGINS				
Congestion					
Coal					
Gas					
Purchased Solar					
Purchased Wind					
Other					
Total NSP System Costs					
Asset-Based Sales Revenues					
Solar Gardens – Above Market					
Renewable Connect					
Net NSP System Costs					
			PROTECTED DATA ENDS]		
MN Jurisdiction Costs	$858,246		$774,267		($83,979)
Solar Gardens – Above Market	$188,579		$247,045		$58,466
Biomass Buyout Costs	$22,421		$8,942		($13,479)
Total MN Costs	$1,069,246		$1,030,253		($38,992)
Total MN Sales (MWh)	27,443		26,842		(601)
MN FCA Rate (cent/kWh)	3.896		3.838		(0.058)

(1) Forecast included in Reply Comments filed July 29, 2022. Approved in December 5, 2022 Commission Order.

The forecast cost decrease for 2024 is driven by lower congestion costs, lower costs for natural gas and coal generation, and lower biomass buyout costs, and is offset by higher forecast costs for purchases from the Solar*Rewards Community program, lower revenues from asset-based sales into the MISO market, and higher purchased wind costs. Each of these drivers will be discussed in the remainder of this section.

i. Congestion Costs

Congestion costs **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for 2024 as compared to authorized costs for 2023. The forecast of congestion costs is based on actual data which has **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** as shown in Figure 1. Congestion costs, which have been high since 2021, are primarily driven by large additions of renewable energy in the MISO footprint without sufficient addition of transmission to deliver energy from generators to load centers within the MISO footprint. The Company monitors congestion costs regularly, and if future actual costs show another step change or significant trend, we plan to update accordingly in our July Reply Comments. Part B, Attachment 9 shows MISO costs by category and Part F, Workpaper 5 provides further details on the calculation of forecast costs for 2023.

Figure 1: Congestion Costs

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

ii. Natural Gas Generation Costs

Costs for natural gas-fired generation are forecast to decrease by **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for 2024 as compared to costs authorized for 2023. Natural gas prices as reflected by NYMEX futures for 2024 are 29 percent lower than natural gas prices authorized for 2023. Due to low natural gas prices, and due to lower forecast coal generation, the volume of natural gas-fired generation is forecast to increase for 2024. However, the gas price decrease offsets the increase in volume of generation resulting in a net decrease in costs as shown in Table 3. Forward LMP prices in MISO forecast continued high gas generation for 2024 for system needs as well as for asset-based sales into the MISO market due to the efficient combined-cycle generation in the NSP portfolio.

iii. Coal Generation Costs

Coal generation costs are forecast to decrease by **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for 2024 relative to authorized costs for 2023 as shown in Table 3. The decrease is driven by lower forecast volume of coal generation, primarily due to the retirement of Sherco Unit 2 which is assumed to occur in 2023. Unit costs for coal and rail delivery are forecast to decline slightly, 1 percent, for 2024. Coal generation volumes are also impacted by the EPA "good neighbor" rule assumed to be in effect by the ozone season for 2024.

iv. Biomass Buyout Costs

Costs to terminate biomass purchased power contracts are forecast to decrease by **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for 2024 relative to authorized costs for 2023 as shown in Table 3. The decrease is driven by the final payment for the Laurentian purchase power agreement which occurs in 2023. The remaining biomass buyout costs relate to the Benson purchase power agreement.

v. Purchased Solar Costs

The 2024 test year includes projected increases in the Solar*Rewards Community program. This program is forecast to contribute $42 million of additional cost in 2024 with $58 million direct assigned to the Minnesota jurisdiction in above market costs as shown in Table 3. Above market costs increase for the 2024 forecast because LMP prices for 2024 are projected to be 30 percent lower than those authorized in 2023. This results in less of the program costs being assigned to the NSP jurisdictions as market-cost based energy and more being direct assigned to Minnesota as above market costs. The Solar*Rewards Community program results in an annual FCA rate for Minnesota customers that is $9.20/MWh or 24 percent higher than the rate would be without this program.

vi. Asset-Based Sales Revenues

Forward LMP for the 2024 test year are projected to be 30 percent lower than prices authorized for 2023. The average of the 2024 hourly LMP assumed in the forecast is **[PROTECTED DATA BEGINS**
PROTECTED DATA ENDS] that was authorized for 2023. LMP has fallen in response to factors that are driving natural gas prices lower in 2024. Lower LMPs for 2024 are resulting in forecast asset-based sales revenues that are **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** than revenues authorized for 2023, as shown in Table 3. Despite the decrease, revenue from off-system sales is still providing a significant offset to costs forecast for 2024.

vii. Purchased Wind Costs

Purchased wind costs for the 2024 test year also increase by **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** as shown in Table 3. The increase is driven by extension of the PPA with MinnDakota which occurred in 2023, in addition to updated wind patterns for wind PPAs which show increased production primarily for the newest wind PPAs on the NSP system.

C. Customer Class Rate Calculation

The Company proposes to allocate fuel clause costs to Minnesota using the FERC-approved Interchange Agreement tariff, which governs cost allocation between our NSP-Minnesota and NSP-Wisconsin operating companies. The Interchange Agreement is a formula rate which assigns charges between these two operating companies for costs related to the integrated electric system, including the fuel and purchased power costs that are recovered through the fuel clause. Previously we have used a sales allocator to assign costs to the Minnesota jurisdiction for the fuel clause calculation, which can produce a different level of costs assigned to Minnesota than the Interchange Agreement actually assigns under the tariff. In this filing, we have assigned costs to the NSP-Minnesota operating company through the application of the Interchange Agreement energy allocator. We then allocated the NSP-Minnesota fuel costs to the Minnesota jurisdiction using the sales allocator. This allows customers and the Company to remain whole on prudently incurred fuel cost recovery, as Minnesota customers would pay for their allocation of the fuel costs assigned to the NSPM operating company.

To determine the proposed monthly fuel cost by customer class, we take the 2024 NSP system forecasted costs, and add in the forecasted recovery of the Minnesota jurisdiction biomass PPA termination costs and the above market Community Solar Gardens costs which are direct-assigned to the Minnesota jurisdiction. The sum of the Minnesota jurisdiction costs divided by the forecasted Minnesota jurisdiction MWh sales subject to the FCA (excluding Renewable*Connect program MWh) yields the Minnesota jurisdiction per unit cost. This per unit cost multiplied by the Fuel Adjustment Factor (FAF), including the Class Ratio Adjustment, determines the proposed monthly class fuel cost charge (FCC) factors. Finally, a Class Ratio Adjustment is applied in order to match forecasted recovery with forecasted expense. Part A, Attachment 1, page 3 shows the development of the adjustment and class rates, as well as the resulting total fuel revenues which equal total forecasted fuel expense. Part A, Attachment 1, page 2 summarizes the rates by month and by customer class using the Class Ratio Adjustment.

D. Assumptions Regarding Pending Commission Proceedings

Commission action on the following proceedings could impact our 2024 actual fuel costs:

- Renewable*Connect (Docket No. E002/M-21-222) – limited program modifications and updated pricing

If the Commission acts on this proceeding in the coming months, we will adjust our fuel forecast in our Reply Comments as necessary.

III. MANAGING PRICE RISK VOLATILITY

The Company addresses fuel and purchased power price risk through an integrated analysis of its future costs. The Company manages risk associated with planned outages by scheduling maintenance for its generating facilities during periods when energy demand, and prices, is expected to be relatively low. These periods typically occur in the fall and spring when weather conditions are more moderate. The Company submits outage information to MISO for approval.

In a separate analysis, the Company analyzes its FTR position in the MISO market to ensure that the Company is hedged to the extent possible against congestion cost risk. The Company operates in the MISO wholesale energy and ancillary services market, which uses security constrained regional dispatch with LMP and FTRs to provide a partial hedge against congestion risk. The Company periodically reviews its FTR portfolio to ensure that it is properly hedged, given the limitations of the FTR auction process, against congestion cost risk in the MISO day-ahead market (there is no FTR protection in the real-time market). The Company analyzes key congestion risks between our generation and purchase power nodes and our load nodes to determine the optimal FTR portfolio. The Company can adjust this portfolio annually through the MISO FTR allocation process and monthly through the FTR auction process. **[PROTECTED DATA BEGINS**
PROTECTED DATA ENDS]

Finally, the Company reviews its exposure to fuel price risk. Historically, this has been a long-term issue for the NSP System due to the predominance of coal and nuclear energy in our generation fleet, but the increase in natural gas-fired generation and purchased power in the resource portfolio helps mitigate this risk.

Xcel Energy's current coal acquisition strategy **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. Implementation of this strategy **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] Xcel Energy's strategy is **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] Xcel Energy's coal acquisition strategy also **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

The Company contracts for natural gas storage with Northern Natural Gas (NNG) and ANR Pipeline to provide operational flexibility and to ensure availability of fuel for power plant operations. Storage gas also provides price stability and certainty throughout the year as previously stored gas can be withdrawn to displace daily spot purchases if and when market prices spike. Gas stored with ANR Pipeline is purchased during the summer and used as a source of supply during the winter months. The Company's storage service with NNG is provided under a service requested by NSP specifically for electric generation customers effective June 1, 2018. Through this service, NSP-has more flexibility to inject and withdraw throughout the year to manage daily swings in demand for gas fired generation. Unlike traditional storage services, which must be filled during the summer months for use during the winter, the new Electric Generation service on NNG allows for withdrawals, and hence protection, against price volatility year-round, including the summer months when electric demand peaks. With the potential variability in generating units being dispatched, a significant portion of system requirements may be covered through use of storage, therefore the Company does not use financial instruments to hedge natural gas.

IV. COMPLIANCE ITEMS

A. MISO Day 2 Reporting

In compliance with the Commission's December 21, 2005 ORDER ESTABLISHING SECOND INTERIM ACCOUNTING FOR MISO DAY 2 COSTS, PROVIDING FOR REFUNDS, AND INITIATING INVESTIGATION in Docket No. E002/M-04-1970 *et al.*, this section provides information related to MISO Day 2 accounting and activity. Specifically, we provide the following information in compliance with the Order:

5. Each petitioner shall limit its level of activity in the real-time market to five percent of total purchases for retail customers, or make real-time market activities subject to prudence review on an annual basis in the annual automatic adjustment of charges docket arising pursuant to Minnesota Rules part 7825.2810.

The Company's real-time market strategy currently is **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. The Company believes that this strategy meets the intent of the Commission's Order in Docket No. E002/M-04-1970 **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS].

Other compliance with this Order will be addressed as needed in the March 1 True-Up filing.

B. Rule Variances

The Commission's July 21, 2017 Order in Docket No. E999/AA-15-611 requires electric utilities to identify all dockets in which the Commission has granted rule variances to a utility's FCA (such as those authorizing true-up provisions, those allowing costs of purchased power adjustments to flow through the FCA, and those allowing MISO costs and revenues to be included in the FCA). Please see Part C, Attachment 2 for a list of relevant dockets.

The Commission's December 12, 2018 Order varied Minn. R. 7825.2600, subp. 3 and June 12, 2019 Order varied Minn. R. 7825.2800, .2810, .2820, .2830, and .2840 to accommodate the new fuel cost adjustment method and process.[7]

We note that prior to Fuel Clause Reform, the Commission had approved regular variances to the Fuel Clause Rules allowing the Company to implement forecasted rates on a monthly basis. In compliance with the Commission's December 1, 2017 Order in Docket No. E002/M-17-445, the Fuel Clause Reform process has superseded this rule variance approval.

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[7] Docket No. E999/CI-03-802

V. REPORTING IN COMPLIANCE WITH MINNESOTA RULES

This filing contains information provided in response to the annual reporting requirements specified in the following rule sections:

7825.2800 Policies and Actions
7825.2810 Annual Report of Automatic Adjustment Charges
7825.2830 Annual Five-Year Projection
7825.2840 Annual Notice of Reports Availability

A. 7825.2800 Annual Reports: Policies and Actions

Part D, Attachments 1-10 include information and supporting data in compliance with the following topics listed in Minn. Rule 7825.2800:

- Procurement Policies
- Dispatching Policies and Procedures
- Fuel Supply
- Conservation and Load Management Policy
- Other Actions

This information was also filed in the March 1, 2023 Annual Fuel Forecast True-Up Report, which included compliance items required to be filed in the Company's Annual Automatic Adjustment of Charges Report for the January-December 2022 period (Docket No. E999/AA-21-295). We will update Part D in our March 1, 2024 True-Up filing as necessary to reflect any changes between the 2023 forecast and actuals.

B. 7825.2810 Annual Report: Automatic Adjustment of Charges

Minn. Rule 7825.2810 requires the following information:

- Base Cost of Fuel
- Billing Adjustment Amounts Charged Customers for Each Month
- Total Cost of Fuel Delivered to Customers
- Revenue Collected from Customers for Energy Delivered
- Monthly Fuel Cost Charge

At this time, we are able to provide information about the Base Cost of Fuel below, and we have specified the Monthly Fuel Cost Charges as proposed in this filing. We will provide the remainder of these requirements in our March 1, 2023 True-Up Filing.

1. Base Cost of Energy

On November 2, 2015, the Company filed a Petition to increase electric rates (Docket No. E002/GR-15-826). A new Base Cost of Energy of $0.02680 per kWh was approved in the associated docket, and went into effect January 1, 2016.[8] The Commission issued its Order approving the rate case on June 12, 2017. Final rates were implemented on October 1, 2017. The approved FAF Ratios and Base Cost of Energy by the Service Category currently in effect are shown in Part A, Attachment 1.

The Commission's November 5, 2019 Order in Docket No. E999/CI-03-802 approved the Company's proposal to use fuel costs from the Company's latest "Annual Fuel Forecast" in some elements of future electric rate cases, and eliminate the base cost of energy rate from our Fuel Clause Rider tariff. The Company updated its tariff language in accordance with the Commission's Order.

2. Monthly Fuel Cost Charges

See Tables 1 and 2 and Part A, Attachment 1, page 2 of this Petition for the monthly fuel cost charges we propose to implement in 2024.

C. 7825.2830 Annual Five-Year Projection

The fuel cost forecast summarized per unit, cost and energy for the 2024 test year is provided in Part A, Attachments 1 through 3. The monthly projection of fuel cost by energy source for the 2024 test year is provided as Part B, Attachments 2 through 4.

The fuel cost forecast summarized per unit, cost and energy for the four years beyond the 2024 test year is provided in Part E, Attachments 1 through 3. The monthly projection of fuel cost by energy source for the four years beyond the 2024 test year is provided as Part E, Attachments 4 through 6.

D. 7825.2840 Annual Notice of Reports Availability

Minn. Rule 7825.2840 requires utilities to provide notice of the availability of the reports defined in parts 7825.2800 to 7825.2830 to all intervenors in the utility's two previous general rate cases. In compliance with this Rule, the Company is providing

[8] Docket No. E002/MR-15-827

notice to all intervenors in our 2015 and 2021 electric rate cases who have requested to remain on the docket service lists.

CONCLUSION

Xcel Energy respectfully requests the Commission approve our 2024 Annual Fuel Forecast, resulting proposed monthly fuel cost charges for the months of January-December 2024, and corresponding proposed tariff revision reflecting the monthly fuel cost charges.

Dated: May 1, 2023

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissione
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2024 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-23-153

PETITION

SUMMARY

Please take notice that on May 1, 2023 Northern States Power Company, doing business as Xcel Energy, submitted to the Minnesota Public Utilities Commission a Petition for approval of our 2024 Annual Fuel Forecast and resulting proposed monthly fuel cost charges for the months of January-December 2024 in compliance with the Commission's December 17, 2017, December 12, 2018, and June 12, 2019 Orders in Docket No. E999/CI-03-802. This Petition also complies with Minn. Rule 7825.2830.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2024 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-23-153

NOTICE OF REPORT AVAILABILITY

On May 1, 2023, Northern States Power Company, doing business as Xcel Energy, filed a Petition with the Minnesota Public Utilities Commission which provided information in compliance with the following MPUC Rules:

7825.2800 Annual Reports; Policies & Actions
7825.2810 Annual Report; Automatic Adjustment Charges
7825.2830 Annual Five-Year Projection
7825.2840 Annual Notice of Reports Availability

The Petition primarily addresses the Company's fuel forecast and resulting monthly fuel rates for the 2024 calendar year, but also complies with additional fuel clause related reporting requirements under various Commission Orders.

The aforementioned report is available for public inspection at the MPUC offices, 121 East 7th Place, Suite 350 St. Paul, MN 55101-2147, on the Minnesota Department of Commerce edockets website (https://www.edockets.state.mn.us/EFiling) and upon written request to the following:

Xcel Energy
Regulatory Administration
414 Nicollet Mall – 401 7th Floor
Minneapolis, MN 55401

TRADE SECRET JUSTIFICATION:

Under Minnesota Stat. § 13.37, trade secret information is defined as including a compilation of government data that 1) was supplied by the affected individual or organization, 2) is subject of efforts by the individual or organization that are reasonable under the circumstances to maintain its secrecy, and 3) derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

The fuel supply, fuel cost, fuel cost forecast and wind curtailment information designated as Trade Secret in this Petition meets this definition for the following reasons:

1. This information meets the first criterion as it is submitted by Xcel Energy, which is an affected organization.

2. The information meets the second criterion in the statute because Xcel Energy makes extensive efforts to maintain the secrecy of this information. The information is not available outside of the Company except to (i) other parties to applicable contracts subject to the confidentiality and non-disclosure provisions contained in such contracts, and (ii) regulatory agencies under the confidentiality provisions of state or federal law.

3. The information meets the third criterion in the statute because the information has economic value to Xcel Energy, its customers, suppliers, and competitors. First, if suppliers knew the terms of Xcel Energy's electric and fuel supply and transportation contracts, they may be able to use this knowledge to fashion bids to Xcel Energy. While their bids may be competitive with existing contracts, they could be at a price higher than the best price the supplier can offer or the current market price. Second, suppliers will be reluctant to offer special favorable terms to Xcel Energy if they know other competitors or customers will gain knowledge of the terms and demand similar terms in the future. Third, competitors of Xcel Energy also purchase these services. These competitors may be able to leverage knowledge of Xcel Energy's costs to gain similar terms or may negotiate slightly better prices from the supplier. Any of these results would harm Xcel Energy and its customers. Because Xcel Energy competes for purchased energy, fuel and transportation services in a competitive marketplace, disclosure would directly harm Xcel Energy by making its delivered supply costs less competitive. The forecast of

future fuel costs includes assumptions of future market prices for fuel not yet procured under contract. This information would give future potential suppliers knowledge of Xcel Energy's forecast of fuel prices that may not be the actual market price when procurement bids are requested. This knowledge may directly affect the prices submitted under bid or renegotiated during contract renewal.

Contract confidentiality clauses in existing fuel supply and other applicable contracts require suppliers' authorization prior to the release of any information pertaining to contract terms and conditions. Suppliers limit the public disclosure of this information to maintain their competitive position in the marketplace. Fuel and transportation services are not purchased in an open, commoditized marketplace. Prices are the result of closed bidding or direct negotiations and are not publicly available.

Xcel Energy requests Trade Secret protection of this information to maintain the Company's competitive position in the marketplace. If our competitors knew our pricing information, they could use it to possibly extract advantageous terms from Xcel Energy or other suppliers, which would result in financial harm to Xcel Energy and its customers.

Part F and G Workpapers Trade Secret in Their Entirety

Part F, Workpapers 1 through 5 and Part G, Workpapers 3, 4, 5, 6, 7, 8, 9 and 10 provided with the Not Public version of this filing contain data classified as trade secret pursuant to Minn. Stat. §13.37, subd. 1(b) and are marked as "Not Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: The workpapers contain Confidential and Proprietary forecast modeling inputs from PLEXOS, including contract terms and forecasted market pricing.
2. **Authors:** The data is output from PLEXOS and prepared under the direction of Dave Horneck.
3. **Importance:** The workpapers contain competitively sensitive data related to modeling inputs and has economic value to Xcel Energy, its customers, suppliers, and competitors. The knowledge of such information could adversely impact future contract negotiations, potentially increasing costs for these services for our customers.
4. **Date the Information was Prepared**: The information was prepared in April 2023.

TABLE OF CONTENTS

Part E: 5-Year Forecast – MN Rule 7825.2830

Part F: Modeling and Market Workpapers and Supporting Data

Part G: Fuel Forecast Workpapers and Supporting Data

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2024 - Dec 2024

Protected Data is shaded.

Line #	*Costs in $1,000's*	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024	2024 Total
1														
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens (CSG)	$14,599	$21,710	$29,260	$33,691	$39,318	$34,634	$40,978	$39,184	$27,579	$21,727	$14,741	$11,842	$329,263
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	MISO Market Charges													
25	Subtotal													
26														
27	**Total NSP System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**	($9,071)	($13,744)	($24,016)	($27,215)	($32,232)	($26,744)	($28,587)	($27,890)	($20,805)	($16,566)	($11,293)	($8,881)	($247,045)
31	**Less Renewable*Connect Pilot**													
32	**Less Renewable*Connect MTM**													
33	**Less Renewable*Connect LT**													
34														
35	**NSP Net System Costs Excluded CSG Above Market**													
36	**& Renewable*Connect Costs**													
37														
38	**Interchange Agreement Energy Req Allocator**													
39														
40	**NSPM System Costs Excluded CSG Above Market**													
41	**& Renewable*Connect Costs**													
42														
43	**NSPM System Calendar Month MWh Sales**													
44														
45	**Less Renewable*Connect Pilot MWh Sales**													
46	**Less Renewable*Connect MTM MWh Sales**													
47	**Less Renewable*Connect LT MWh Sales**													
48														
49	**Net NSPM System Calendar Month MWh Sales**													31,199,824
50														
51	**NSPM System Cost in cents/kWh**													
52														
53	**Minnesota Jurisdiction MWh Sales**													
54														
55	**Less Renewable*Connect Pilot MWh Sales**													
56	**Less Renewable*Connect MTM MWh Sales**													
57	**Less Renewable*Connect LT MWh Sales**													
58														
59	**Net MN MWh Sales**													26,842,355
60														
61	**MN Fuel Cost**													
62	**Solar Gardens - Above Market Cost**	$9,071	$13,744	$24,016	$27,215	$32,232	$26,744	$28,587	$27,890	$20,805	$16,566	$11,293	$8,881	$247,045
63	**Laurentian Buyout costs**													
64	**Pine Bend Buyout Cost**													
65	**Benson Buyout Cost**													
66														
67	**Forecast MN FCA Costs**													$1,030,253
68														
69														
70	**Forecast MN FCA Cost in cents/kWh**													**3.838**
71														
72														
73	**Forecast MN FCA Cost in $/MWh**													$38.38

PROTECTED DATA ENDS]

Proposed 2024 Monthly Fuel Clause Charges ($/KWh)

	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
January	$0.03388	$0.03430	$0.03324	$0.04154	$0.02721	$0.02658
February	$0.03637	$0.03683	$0.03568	$0.04460	$0.02920	$0.02852
March	$0.03937	$0.03987	$0.03863	$0.04829	$0.03161	$0.03088
April	$0.04222	$0.04275	$0.04142	$0.05178	$0.03390	$0.03311
May	$0.04512	$0.04569	$0.04427	$0.05533	$0.03623	$0.03539
June	$0.04233	$0.04287	$0.04153	$0.05192	$0.03399	$0.03320
July	$0.04253	$0.04307	$0.04172	$0.05218	$0.03412	$0.03333
August	$0.04218	$0.04271	$0.04138	$0.05175	$0.03385	$0.03307
September	$0.03899	$0.03948	$0.03825	$0.04782	$0.03129	$0.03057
October	$0.03806	$0.03854	$0.03734	$0.04668	$0.03055	$0.02984
November	$0.03505	$0.03549	$0.03438	$0.04299	$0.02813	$0.02748
December	$0.03249	$0.03290	$0.03188	$0.03985	$0.02609	$0.02548

Proposed 2024 Monthly Fuel Clause Charges ($/KWh)

	Commercial & Industrial General TOUService Pilot		
	Demand		
	Peak	Base	Off-Peak
January	$0.04197	$0.03564	$0.01863
February	$0.04507	$0.03826	$0.01998
March	$0.04879	$0.04142	$0.02162
April	$0.05232	$0.04442	$0.02319
May	$0.05591	$0.04747	$0.02480
June	$0.05246	$0.04454	$0.02325
July	$0.05273	$0.04475	$0.02331
August	$0.05229	$0.04438	$0.02314
September	$0.04832	$0.04102	$0.02140
October	$0.04717	$0.04004	$0.02090
November	$0.04344	$0.03687	$0.01924
December	$0.04027	$0.03419	$0.01785

Northern States Power Company
Electric Utility - State of Minnesota
Monthly Fuel Clause Charge January 2024 - December 2024

Docket No. E002/AA-23-153
Petition
Part A, Attachment 1

Protected Data is shaded.

Month Fuel Cost Charges Applied to Customer Billing	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	12 Months
FORECASTED COST OF FUEL													
	[PROTECTED DATA BEGINS												
[1] Forecasted MN Cost in $1,000's													**$1,030,253**
[2] Forecasted Minn. Retail Sales Subject to FCC *													26,842,355
[3] Forecasted MN Cost in cents/kWh [1]/[2]*100													**3.838¢**
												PROTECTED DATA ENDS]	
Class FAF Ratio													
[4] Residential FAF Ratio	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177
[5] C&I Non-Demand FAF Ratio	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305
[6] C & I Demand Non-TOD FAF Ratio	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984
[7] C & I Demand TOD On-Peak FAF Ratio	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486
[8] C & I Demand TOD Off-Peak FAF Ratio	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166
[9] Outdoor Lighting FAF Ratio	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976
2023 Monthly Fuel Cost Charges	**[PROTECTED DATA BEGINS**												
[10] Residential [3]*[4]													
[11] C & I Non-Demand [3]*[5]													
[12] C & I Demand Non-TOD [3]*[6]													
[13] C & I Demand TOD On-Peak [3]*[7]													
[14] C & I Demand TOD Off-Peak [3]*[8]													
[15] Outdoor Lighting [3]*[9]													
MN Retail MWh Subject to FCA *													
[16] Residential													
[17] C & I Non-Demand													
[18] C & I Demand Non-TOD													
[19] C & I Demand TOD On-Peak													
[20] C & I Demand TOD Off-Peak													
[21] Outdoor Lighting													
[22] Total													26,842,355
2024 Class Fuel Cost Revenues in $1,000's													
[23] Residential [10]*[16]/100													
[24] C & I Non-Demand [11]*[17]/100													
[25] C & I Demand Non-TOD [12]*[18]/100													
[26] C & I Demand TOD On-Peak [13]*[19]/100													
[27] C & I Demand TOD Off-Peak [14]*[20]/100													
[28] Outdoor Lighting [15]*[21]/100													
[29] Total [23]+[24]+[25}+[26]+[27]+[28]													$1,028,391
[30] **2024 Cost vs Revenue Diff in $1,000's** [1]-[29]													
[31] **2024 Cost vs Revenue Diff in $1,000's** [30]													
[32] **MN Retail MWh Subject to FCA *** [22]													
[33] **Monthly Class Ratio Adjustment** [31]/[32]*100													
													PROTECTED DATA ENDS]
2024 Proposed Monthly Fuel Cost Charges in $/kWh													
[34] **Residential** [10]/100+[33]/100	**$0.03388**	**$0.03637**	**$0.03937**	**$0.04222**	**$0.04512**	**$0.04233**	**$0.04253**	**$0.04218**	**$0.03899**	**$0.03806**	**$0.03505**	**$0.03249**	
[35] **C & I Non-Demand** [11]/100+[33]/100	**$0.03430**	**$0.03683**	**$0.03987**	**$0.04275**	**$0.04569**	**$0.04287**	**$0.04307**	**$0.04271**	**$0.03948**	**$0.03854**	**$0.03549**	**$0.03290**	
[36] **C & I Demand Non-TOD** [12]/100+[33]/100	**$0.03324**	**$0.03568**	**$0.03863**	**$0.04142**	**$0.04427**	**$0.04153**	**$0.04172**	**$0.04138**	**$0.03825**	**$0.03734**	**$0.03438**	**$0.03188**	
[37] **C & I Demand TOD On-Peak** [13]/100+[33]/100	**$0.04154**	**$0.04460**	**$0.04829**	**$0.05178**	**$0.05533**	**$0.05192**	**$0.05218**	**$0.05175**	**$0.04782**	**$0.04668**	**$0.04299**	**$0.03985**	
[38] **C & I Demand TOD Off-Peak** [14]/100+[33]/100	**$0.02721**	**$0.02920**	**$0.03161**	**$0.03390**	**$0.03623**	**$0.03399**	**$0.03412**	**$0.03385**	**$0.03129**	**$0.03055**	**$0.02813**	**$0.02609**	
[39] **Outdoor Lighting** [15]/100+[33]/100	**$0.02658**	**$0.02852**	**$0.03088**	**$0.03311**	**$0.03539**	**$0.03320**	**$0.03333**	**$0.03307**	**$0.03057**	**$0.02984**	**$0.02748**	**$0.02548**	

* Excluded Renewable*Connect MWh

2024 Proposed Costs verses Revenues													
2023 Class Fuel Cost Revenues in $1,000's	**[PROTECTED DATA BEGINS**												
[40] Residential [34]*[16]													
[41] C & I Non-Demand [35]*[17]													
[42] C & I Demand Non-TOD [36]*[18]													
[43] C & I Demand TOD On-Peak [37]*[19]													
[44] C & I Demand TOD Off-Peak [38]*[20]													
[45] Outdoor Lighting [39]*[21]													
[46] Total [40]+[41]+[42}+[43]+[44]+[45]													$1,030,241
[47] Total Forecasted MN Costs [1]													$1,030,253
[48] **2023 Cost vs Revenue Diff in $1,000's** [47]-[46]													$12
													PROTECTED DATA ENDS]

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NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Monthly Fuel Clause Charge January 2024 - December 2024
C&I General Time of Use Service Pilot Program

Protected Data is shaded.

	Monthly Fuel Cost Charges Applied to Customer Billing	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	12 Months
	Forecasted Cost of Fuel													
		[PROTECTED DATA BEGINS												
[1]	Forecasted MN Cost in $1,000's													**$1,030,253**
[2]	Forecasted Minn. Retail Sales Subject to FCC *													26,842,355
[3]	**Forecasted MN Cost in cents/kWh** [1]/[2]*100													**3.838¢**
													PROTECTED DATA ENDS]	
	Class FAF Ratio													
[4]	C&I Demand General TOU Peak Ratio	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617
[5]	C&I Demand General TOU Base Ratio	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708
[6]	C&I Demand General TOU Off-Peak Ratio	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579
	2024 Monthly Fuel Cost Charges	**[PROTECTED DATA BEGINS**												
[7]	**C&I Demand General TOU Peak** [3]*[4]													
[8]	**C&I Demand General TOU Base** [3]*[5]													
[9]	**C&I Demand General TOU Off-Peak** [3]*[6]													
[10]	**Monthly Class Ratio Adjustment**													
														PROTECTED DATA ENDS]
	2024 Proposed Monthly Fuel Cost Charges in $/kWh													
[11]	**C&I Demand Generl TOU Peak** [7]+[10]	**$0.04197**	**$0.04507**	**$0.04879**	**$0.05232**	**$0.05591**	**$0.05246**	**$0.05273**	**$0.05229**	**$0.04832**	**$0.04717**	**$0.04344**	**$0.04027**	
[12]	**C&I Demand General TOU Base** [8]+[12]	**$0.03564**	**$0.03826**	**$0.04142**	**$0.04442**	**$0.04747**	**$0.04454**	**$0.04475**	**$0.04438**	**$0.04102**	**$0.04004**	**$0.03687**	**$0.03419**	
[13]	**C&I Demand General TOU Off-Peak** [9]+[13]	**$0.01863**	**$0.01998**	**$0.02162**	**$0.02319**	**$0.02480**	**$0.02325**	**$0.02331**	**$0.02314**	**$0.02140**	**$0.02090**	**$0.01924**	**$0.01785**	

* Excluded Renewable*Connect MWh

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2024 - Dec 2024

Protected Data is shaded.

Line #														
1	*Energy in GWhs*	**1/1/2024**	**2/1/2024**	**3/1/2024**	**4/1/2024**	**5/1/2024**	**6/1/2024**	**7/1/2024**	**8/1/2024**	**9/1/2024**	**10/1/2024**	**11/1/2024**	**12/1/2024**	**2024 Total**
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	102.5	152.4	205.5	236.6	276.1	243.2	287.7	275.1	193.6	152.6	103.5	83.1	2,311.9
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System GWh**													
27														
28	**Less Sales GWh**													
29	**Less Renewable*Connect Pilot GWh**													
30	**Less Renewable* Connect MTM GWh**													
31	**Less Renewable* Connect LT GWh**													
32														
33	**Net System GWh**													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2024 - Dec 2024

Protected Data is shaded.

Line #														
1	*$/MWh*	**1/1/2024**	**2/1/2024**	**3/1/2024**	**4/1/2024**	**5/1/2024**	**6/1/2024**	**7/1/2024**	**8/1/2024**	**9/1/2024**	**10/1/2024**	**11/1/2024**	**12/1/2024**	**2024 Total**
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System $/MWh**													
27														
28	**Less Sales**													
29	**Less Solar Gardens - Above Market Cost**	$88.49	$90.16	$116.89	$115.05	$116.75	$109.98	$99.36	$101.37	$107.44	$108.59	$109.11	$106.81	$106.86
30	**Less Renewable*Connect Pilot**													
31	**Less Renewable* Connect MTM**													
32	**Less Renewable*Connect LT**													
33														
34	**Net System $/MWh**													$25.90

PROTECTED DATA ENDS]

2024 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,460	3,801,376	79.10%
February	6,049	3,398,442	80.72%
March	5,816	3,541,854	81.85%
April	5,331	3,136,433	81.71%
May	6,948	3,356,735	64.94%
June	8,476	3,798,984	62.25%
July	9,147	4,330,174	63.63%
August	8,764	4,134,064	63.40%
September	7,722	3,473,390	62.47%
October	5,758	3,325,068	77.61%
November	5,812	3,313,002	79.18%
December	6,197	3,684,863	79.93%
Annual	**9,147**	**43,294,386**	**53.88%**

Redline

FUEL COST FACTORS (202~~3~~4)

Month	Residential	Commercial & Industrial Non-Demand	Commercial & Industrial Non-TOD	Commercial & Industrial Demand On-Peak	Commercial & Industrial Off-Peak	Outdoor Lighting	
January	$0.03~~316~~388	$0.03~~358~~430	$0.03~~254~~324	$0.04~~066~~154	$0.02~~663~~721	$0.026~~01~~58	R
February	$0.036~~15~~37	$0.036~~61~~83	$0.035~~46~~68	$0.044~~35~~60	$0.029~~01~~20	$0.028~~33~~52	
March	$0.0~~4273~~3937	$0.0~~4327~~3987	$0.0~~4193~~3863	$0.0~~5243~~4829	$0.03~~429~~161	$0.03~~349~~088	
April	$0.04~~761~~222	$0.04~~822~~275	$0.04~~671~~142	$0.05~~839~~178	$0.03~~823~~390	$0.03~~734~~311	
May	$0.04~~881~~512	$0.04~~942~~569	$0.04~~788~~427	$0.05~~986~~533	$0.03~~919~~623	$0.03~~827~~539	
June	$0.0~~5107~~4233	$0.0~~5172~~4287	$0.0~~5011~~4153	$0.0~~6266~~5192	$0.0~~4100~~3399	$0.0~~4004~~3320	
July	$0.04~~561~~253	$0.04~~618~~307	$0.04~~474~~172	$0.05~~595~~218	$0.03~~659~~412	$0.03~~574~~333	
August	$0.04~~547~~218	$0.04~~604~~271	$0.04~~461~~138	$0.05~~580~~175	$0.03~~648~~385	$0.03~~563~~307	
September	$0.0~~4175~~3899	$0.0~~4227~~3948	$0.0~~4095~~3825	$0.0~~5121~~4782	$0.03~~351~~129	$0.03~~273~~057	
October	$0.038~~81~~06	$0.03~~930~~854	$0.03~~808~~734	$0.04~~761~~668	$0.03~~115~~055	$0.0~~3043~~2984	
November	$0.035~~80~~05	$0.03~~625~~549	$0.03~~512~~438	$0.04~~392~~299	$0.028~~73~~13	$0.02~~806~~748	
December	$0.03~~303~~249	$0.03~~345~~290	$0.03~~241~~188	$0.0~~4051~~3985	$0.026~~52~~09	$0.025~~91~~48	R

Commercial & Industrial General TOU Service Pilot Program ~~N~~R

Month	Peak	Base	Off-Peak	
January	$0.041~~09~~97	$0.03~~489~~564	$0.018~~23~~63	
February	$0.04~~482~~507	$0.038~~03~~26	$0.019~~82~~98	
March	$0.0~~5298~~4879	$0.04~~497~~142	$0.02~~343~~162	
April	$0.05~~901~~232	$0.0~~5010~~4442	$0.02~~616~~319	
May	$0.0~~6048~~5591	$0.0~~5135~~4747	$0.02~~681~~480	
June	$0.0~~6331~~5246	$0.0~~5374~~4454	$0.02~~803~~325	
July	$0.05~~653~~273	$0.04~~798~~475	$0.02~~501~~331	
August	$0.05~~638~~229	$0.04~~785~~438	$0.02~~491~~314	
September	$0.0~~5174~~4832	$0.04~~392~~102	$0.02~~291~~140	
October	$0.04~~811~~717	$0.04~~084~~004	$0.02~~129~~090	
November	$0.04~~438~~344	$0.03~~767~~687	$0.019~~63~~24	
December	$0.040~~93~~27	$0.034~~75~~19	$0.01~~815~~785	~~N~~R

CURRENT PERIOD COST OF ENERGY
The Current Period Cost of Energy per kWh is defined as the qualifying costs, forecasted to be incurred during the calendar month, divided by the kWh sales forecasted for the same month. Qualifying kWh sales are all kWh

(Continued on Sheet No. 5-91.2)

sales excluding intersystem, Renewable*Connect, Renewable*Connect Government and Windsource® Program kWh sales. Qualifying costs are the sum of the following:

~~M~~

~~M~~

(Continued on Sheet No. 5-91.2)

Clean

FUEL COST FACTORS (2024)

Month	Residential	Commercial & Industrial Non-Demand	Demand Non-TOD	Demand On-Peak	Demand Off-Peak	Outdoor Lighting	
January	$0.03388	$0.03430	$0.03324	$0.04154	$0.02721	$0.02658	R
February	$0.03637	$0.03683	$0.03568	$0.04460	$0.02920	$0.02852	
March	$0.03937	$0.03987	$0.03863	$0.04829	$0.03161	$0.03088	
April	$0.04222	$0.04275	$0.04142	$0.05178	$0.03390	$0.03311	
May	$0.04512	$0.04569	$0.04427	$0.05533	$0.03623	$0.03539	
June	$0.04233	$0.04287	$0.04153	$0.05192	$0.03399	$0.03320	
July	$0.04253	$0.04307	$0.04172	$0.05218	$0.03412	$0.03333	
August	$0.04218	$0.04271	$0.04138	$0.05175	$0.03385	$0.03307	
September	$0.03899	$0.03948	$0.03825	$0.04782	$0.03129	$0.03057	
October	$0.03806	$0.03854	$0.03734	$0.04668	$0.03055	$0.02984	
November	$0.03505	$0.03549	$0.03438	$0.04299	$0.02813	$0.02748	
December	$0.03249	$0.03290	$0.03188	$0.03985	$0.02609	$0.02548	R

Commercial & Industrial General TOU Service Pilot Program

Month	Peak	Base	Off-Peak	
January	$0.04197	$0.03564	$0.01863	R
February	$0.04507	$0.03826	$0.01998	
March	$0.04879	$0.04142	$0.02162	
April	$0.05232	$0.04442	$0.02319	
May	$0.05591	$0.04747	$0.02480	
June	$0.05246	$0.04454	$0.02325	
July	$0.05273	$0.04475	$0.02331	
August	$0.05229	$0.04438	$0.02314	
September	$0.04832	$0.04102	$0.02140	
October	$0.04717	$0.04004	$0.02090	
November	$0.04344	$0.03687	$0.01924	
December	$0.04027	$0.03419	$0.01785	R

CURRENT PERIOD COST OF ENERGY
The Current Period Cost of Energy per kWh is defined as the qualifying costs, forecasted to be incurred during the calendar month, divided by the kWh sales forecasted for the same month. Qualifying kWh sales are all kWh sales excluding intersystem, Renewable*Connect, Renewable*Connect Government and Windsource® Program kWh sales. Qualifying costs are the sum of the following:

(Continued on Sheet No. 5-91.2)

Methodology

PLEXOS® is built on a mathematical programming foundation that supports all the popular third-party commercial solver tools (CPLEX, Gurobi, MOSEK, Xpress-MP and others). A unique and compelling feature of the software is the dynamic problem formulation engine. This builds the mathematical representation of the task at hand, whether it's long-term capacity planning or short-term UC/ED, from scratch at runtime, adjusting the formulation of each element based on defined data and user settings. This creates the most efficient formulation possible and allows users to control the mathematical task's complexity.

PLEXOS® uses a single, consistent user interface and database for all study types from long-term, medium to short term. In all cases the approach used is to formulate and solve one or more stochastic (or deterministic) mixed integer programming problems.

The specific methodology used for selected key features is described in the following table:

Feature	Method	Notes
Security-constrained Unit Commitment/Economic Dispatch	Mixed integer programming	Full co-optimization with ancillary services. Heuristic rounding methods and linear relaxation also available as options
Expansion Planning	Mixed integer programming	Simultaneous generation and transmission optimal expansion over 20+ year timeframe fully integrated with mid and short-term simulations.
Network and Optimal Power Flow	Linearized DC-OPF	State-of-the-art linearized DC-OPF including losses produces solutions very close to AC-OPF. AC-PF ex-post computation of voltage and reactive power flows in development.
Hydro	Stochastic or Deterministic with Decomposition from mid to short term	Hydro with storage optimized in two-stages from medium term stochastic optimization to short-term with optimized release policies based on state-of-the-art future cost function method.
Pumped Storage	Full intermittent co-optimization	True optimization of pumped storage operation with user-definable timeframe e.g. day or week.
Wind/Solar/Other Renewable	Detailed and stochastic	Wind and solar generation with forecast uncertainty modeled as stochastic processes.

Market-leading Features

Energy Exemplar® invests heavily in research and development, led by the original developer Dr. Glenn Drayton and his Adelaide, Australia based development team. As a result, PLEXOS® leads the field in scope and depth of features. The following table outlines features that set PLEXOS® software apart from other competing tools.

Feature	Applications
Sub-hourly simulation e.g. 5-minute dispatch	RES,LMP,STO,DSR
Mixed integer programming for unit commitment	RES,OPT,SYS
Co-optimization of energy and ancillary services	RES,STO,DSR
Nodal transmission model	RES,LMP
Co-optimization of generation and optimal power flow with losses	RES,POL,LMP
Pumped storage optimization	RES,STO
Decomposition of long-term constraints (emission, fuel, hydro, etc)	OPT,IRP
Co-optimization of hydro-thermal dispatch	RES,STO
Cascading hydro network model	HYD
Stochastic optimization of hydro storage	HYD
Stochastic unit commitment	SYS
Long-term capacity expansion planning	CEP,IRP
Long-term integrated with mid and short-term simulations	CEP,MA,IRP
Chronological long and mid-term simulations	CEP,IRP
Multi-commodity market arbitrage (electric, fuel, AS, emissions)	OPT,IRP
CCGT as GT and HRSG components	MA
CHP with Heat Storage	MA
Fuel Stockpiles	FUE
Integrated gas-electric co-optimization	GAS,MA
Models of competition (Bertrand, Cournot)	POL,MA
Generic (user-defined) constraints and decision variables	POL,LMP,DSR
Synthetic stochastic series	HYD,RES
Support for high-performance computing	ADQ,RES,PAR
Choice of mathematical programming solver	-
Published benchmarks against ISO/RTO market scheduling software solutions	-
Interleaved Day-ahead/Hour-ahead/ Real-time market sequential simulations	RES

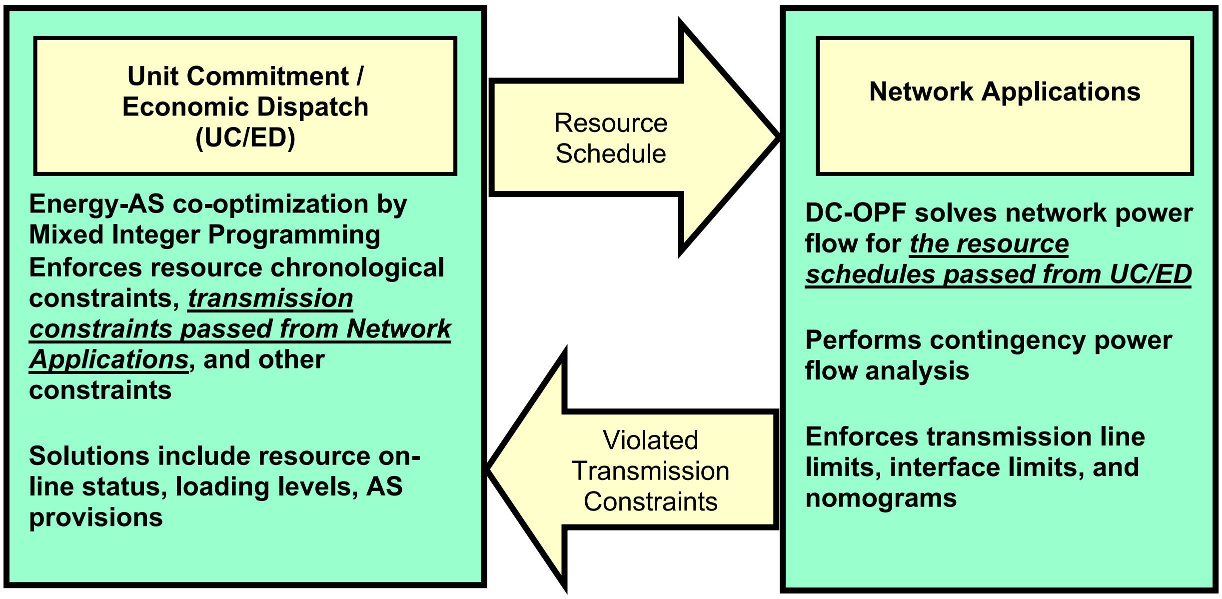
Key to Applications:

Acronym	Description
MA	Electric power market simulation and price forecasting
OPT	Asset portfolio optimization and valuation
CEP	Capacity expansion planning in electric and natural gas systems
LMP	Locational marginal price forecasting
GAS	Natural gas pipeline and storage simulation
RES	Renewable generation integration and flexible resource assessment
STO	Energy storage evaluation
DSR	Demand response valuation
POL	Public policy and interregional transmission planning
GAM	Market power analysis and competition indices
ADQ	Generation adequacy and system reliability calculations
IRP	Integrated resource planning
FUE	Fuel and emission planning
RSK	Risk analysis
HYD	Multi-stage stochastic hydro reservoir optimization
SYS	System operations and real time dispatch
SO	Deterministic, Monte Carlo, and stochastic optimization
DB	Common database for long and short-term simulations
PAR	Parallel and cluster computing

PLEXOS SCUC/ED algorithm

PLEXOS' security constrained unit commitment (SCUC) algorithm consists of two major logics: Unit Commitment using Mixed Integer Programming and Network Applications. The SCUC / ED simulation algorithm can be better described in the following figure. The same SCUC / ED algorithm is used by most ISO or RTO scheduling software (except that AC-OPF may be used by some ISO scheduling software).

Figure 0-1 PLEXOS Security-Constrained Unit Commitment and Economic Dispatch Algorithm



The unit commitment and economic dispatch (UC/ED) logic performs the Energy-AS co-optimization using Mixed Integer Programming enforcing all resource and operation constraints. The UC/ED logic commits and dispatch resources to balance the system energy demand and meet the system reserve requirements.

The resource schedules from the UC/ED are passed to the Network Applications logic. The Network Applications logic solves the DC-OPF to enforce the power flow limits and nomograms. The Network Applications logic also performs the contingency analysis if the contingencies are defined. If there are any transmission limit violations, these transmission limits are passed to the UC/ED logic for the re-run of UC/ED. The iteration continues until all transmission limit violations resolved. Thus the co-optimization solution of Energy-AS-DC-OPF is reached

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels

NOT-PUBLIC DOCUMENT - NOT FOR PUBLIC DISCLOSURE

[PROTECTED DATA BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2024 Total AVG
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Bay Front 5	Wood Coal Gas													
Bay Front 6	Wood Coal Gas													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	AVG COST													
CC LSPower	Gas													
CC MEC I	Gas													
CC MEC II	Gas													
MEC	AVG COST													
CT Invenergy 1	Gas													
CT Invenergy 2	Gas													
CT Invenergy	AVG COST													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
High Bridge 1x1	Gas													
High Bridge 2x1	Gas													
High Bridge	AVG COST													
Inver Hills 2	Gas													
Inver Hills 2	Oil													
Inver Hills 3	Gas													
Inver Hills 3	Oil													
Inver Hills 4	Gas													
Inver Hills 4	Oil													
Inver Hills 5	Gas													
Inver Hills 5	Oil													
Inver Hills 6	Gas													
Inver Hills 6	Oil													
Inver Hills	AVG COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	AVG COST													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal MT Sherburne County													
Sherburne 1	Coal WY Sherburne County													
Sherburne 1	Oil													
Sherburne 3	Coal MT Sherburne County													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Wheaton 1	Gas													
Wheaton 1	Oil													
Wheaton 2	Gas													
Wheaton 2	Oil													
Wheaton 3	Gas													
Wheaton 3	Oil													
Wheaton 4	Gas													
Wheaton 4	Oil													
Wheaton	AVG COST													
Willmarth 1	Gas													
Willmarth 1	RDF													
Willmarth 2	Gas													
Willmarth 2	RDF													
Wilmarth	AVG COST													
System MN	AVG COST													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2024

NOT-PUBLIC DOCUMENT - NOT FOR PUBLIC DISCLOSURE

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2024 Total AVG
		[PROTECTED DATA BEGINS												
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Sherburne 1	Coal MT Sherburne County													
Sherburne 1	Coal WY Sherburne County													
Sherburne 1	Oil													
Sherburne 3	Coal MT Sherburne County													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Coal	AVG COST													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Operations - State of Minnesota
Nuclear Fuel Expense (Units noted in row)

[PROTECTED DATA BEGINS

Item ID	Item Description (Q1-2023 02-13-23 10:50:02)
1	Prairie Island 1 - Heat Generation (1000 MBTU)
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)
3	Prairie Island 1 - Maximum Capacity (MWe-Net)
4	Prairie Island 1 - Current Capability (MWe-Net)
5	Prairie Island 1 - Thermal Capability (MWth)
6	Prairie Island 1 - Monthly Capacity Factor (%)
7	Prairie Island 1 - Monthly Minor Outage Rate (%)
8	Prairie Island 1 - Days Offline in Month for Refuelin
9	Prairie Island 1 - Refueling Outage Start Date
10	Prairie Island 1 - Refueling Outage Start Time (HH.MM
11	Prairie Island 1 - Refueling Outage End Date
12	Prairie Island 1 - Refueling Outage End Time (HH.MM)
13	Prairie Island 1 - Fuel Expense - Dollars
14	Prairie Island 1 - Fuel Expense - Cents/MBTU
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe
16	Prairie Island 2 - Heat Generation (1000 MBTU)
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)
18	Prairie Island 2 - Maximum Capacity (MWe-Net)
19	Prairie Island 2 - Current Capability (MWe-Net)
20	Prairie Island 2 - Thermal Capability (MWth)
21	Prairie Island 2 - Monthly Capacity Factor (%)
22	Prairie Island 2 - Monthly Minor Outage Rate (%)
23	Prairie Island 2 - Days Offline in Month for Refuelin
24	Prairie Island 2 - Refueling Outage Start Date
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM
26	Prairie Island 2 - Refueling Outage End Date
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)
28	Prairie Island 2 - Fuel Expense - Dollars
29	Prairie Island 2 - Fuel Expense - Cents/MBTU
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe
31	Monticello - Heat Generation (1000 MBTU)
32	Monticello - Net Electric Generation (MWHe-Net)
33	Monticello - Maximum Capacity (MWe-Net)
34	Monticello - Current Capability (MWe-Net)
35	Monticello - Thermal Capability (MWth)
36	Monticello - Monthly Capacity Factor (%)
37	Monticello - Monthly Minor Outage Rate (%)
38	Monticello - Days Offline in Month for Refuelin
39	Monticello - Refueling Outage Start Date
40	Monticello - Refueling Outage Start Time (HH.MM
41	Monticello - Refueling Outage End Date
42	Monticello - Refueling Outage End Time (HH.MM)
43	Monticello - Fuel Expense - Dollars
44	Monticello - Fuel Expense - Cents/MBTU
45	Monticello - Fuel Expense - Cents/Kwhe
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities
47	Prairie Island 1 - Cents/Kwhe - Fuel Services
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee
49	Prairie Island 1 - Cents/Kwhe - D&D Fee
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery
51	Prairie Island 1 - Cents/Kwhe - Ohter Global Costs
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities
54	Prairie Island 2 - Cents/Kwhe - Fuel Services
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee
56	Prairie Island 2 - Cents/Kwhe - D&D Fee
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery
58	Prairie Island 2 - Cents/Kwhe - Ohter Global Costs
59	Prairie Island 2 - Cents/Kwhe - AFUDC and A&G
60	Monticello - Cents/Kwhe - Fuel Commodities
61	Monticello - Cents/Kwhe - Fuel Services
62	Monticello - Cents/Kwhe - DOE Disposal Fee
63	Monticello - Cents/Kwhe - D&D Fee
64	Monticello - Cents/Kwhe - End of Life Recovery
65	Monticello - Cents/Kwhe - Ohter Global Costs
66	Monticello - Cents/Kwhe - AFUDC and A&G
67	Prairie Island 1 - EOL Recovery Expense - Dollars
68	Prairie Island 2 - EOL Recovery Expense - Dollars
69	Monticello - EOL Recovery Expense - Dollars

PROTECTED DATA ENDS]

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	Unit	Reason for Outage	Start Date	End Date	Duration (Days)
	[PROTECTED DATA BEGINS				
1					
2					
3					
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41					
42					
43					

PROTECTED DATA ENDS]

	2017	2018	2019	2020	2021	2022		5 Yr Average	ES Adder	Modeled
	[PROTECTED DATA BEGINS									
Monti										
PI1										
PI2										
SHC1										
SHC3										
King										
BD 5/2										
Highbridge										
Riverside										

PROTECTED DATA ENDS]

Unit			MISO Rate
			[PROTECTED DATA BEGINS
1	Angus Anson 2		
2	Angus Anson 3		
3	Angus Anson 4		
4	Black Dog 6		
5	Blue Lake 7		
6	Blue Lake 8		
7	Inver Hills 1		
8	Inver Hills 2		
9	Inver Hills 3		
10	Inver Hills 4		
11	Inver Hills 5		
12	Inver Hills 6		
13	Wheaton 1		
14	Wheaton 2		
15	Wheaton 3		
16	Wheaton 4		
17	Wheaton 6		

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Replacement Power Costs Estimate

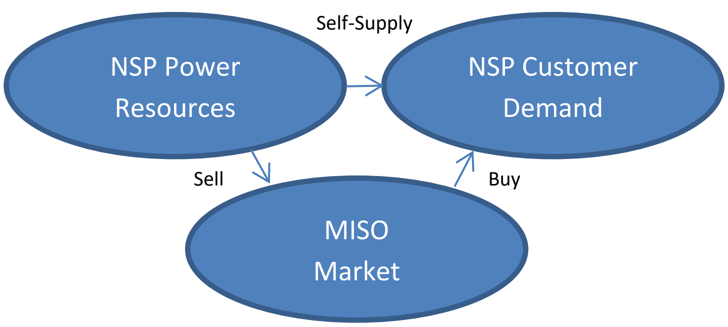
		Planned							Unplanned						
Unit	Type	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh
		[PROTECTED DATA BEGINS													
Black Dog 25	NSP CC														
High Bridge 1x1	NSP CC														
High Bridge 2x1	NSP CC														
Riverside 1x1	NSP CC														
Riverside 2x1	NSP CC														
Allen S King	NSP Coal														
Sherburne 1	NSP Coal														
Sherburne 2	NSP Coal														
Sherburne 3	NSP Coal														
Monticello	NSP Nuclear														
Prairie Island 1	NSP Nuclear														
Prairie Island 2	NSP Nuclear														
Total															
Combined															

PROTECTED DATA ENDS]

MISO Hourly LMP Forecasting in the NSP Production Cost Model

Northern States Power (NSP) buys and sells energy through the MISO market. The energy price is determined by system-wide economic dispatch of power resources to meet customer demand. NSP is a net buyer from the market when energy prices are lower than the cost to serve customers from native generation and a net seller to the market when energy prices are higher than the cost to serve from native generation. Ultimately, the choice between self-supply and buying from (or selling to) MISO is determined by the market energy price. This is a simple and effective construct for modeling purposes, and is reflected in Figure 1.

Figure 1 – Model of NSP Interaction with the MISO Market



The modeled MISO energy price is best represented by the MINN.HUB day-ahead energy price. The MINN.HUB price is a weighted average of price nodes in the northwest region of the MISO market, inclusive of the entire NSP service territory. The day-ahead energy price is used because the NSP production cost model is set-up to predict interaction with the MISO day-ahead market. Further, the day-ahead market clears the vast majority of all energy transacted in MISO making it the most important market to model.

Hourly MINN.HUB LMP Forecast

Four years of historical data are analyzed quarterly using the least square regression model detailed below in order to update the coefficients $a, b,$ and c^M. The regression quantifies the historical relationship between the MINN.HUB Locational Marginal Price (LMP) and load (D_t), wind (W_t), and natural gas (P_d^{NG}). An additional model relates each hour of the day to monthly variations in daily peaks and troughs. The MINN.HUB energy price, or dependent variable, is correlated to the aforementioned price drivers, or independent variables, and applied to forecast price drivers in order to derive an hourly forecast of MINN.HUB prices. The correlation formula is as follows:

$$MISO_t = P_d^{NG}[a(NL_t)^3 + b(NL_t)^{-2} + c^M S_{1..24}^M] \quad (1)$$

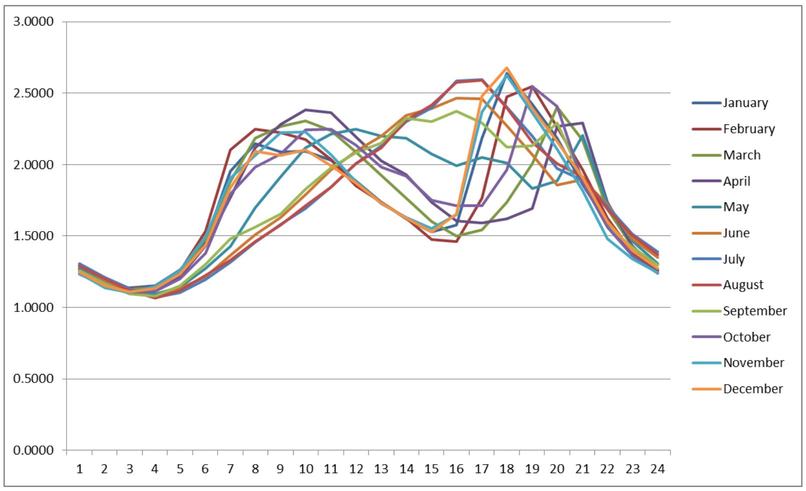
$$P_d^{NG} = Daily\ Natural\ Gas\ Price;\ NL_t = Hourly\ Net\ Load = D_t - W_t$$

$$D_t = Day\ Ahead\ Customer\ Demand;\ \ W_t = \sum_k Wind\ Energy\ DayAhead\ Award_t^k$$

$$S_{1..24}^M = Historic\ Daily\ Price\ Pattern\ by\ Month\ (M = 1,2, \dots ,12)$$

The historical daily price pattern ($S^{M}_{1..24}$) captures monthly changes to the daily price shape. For each month, average historical prices for each hour of the day are ranked from the highest average price hour to the lowest average price hour. An exponential relationship based on this rank is derived, creating a daily price pattern for each month. Example daily price patterns for each month are shown in Figure 2. For consistency, the historical daily price pattern is updated just prior to the least square regression analysis.

Figure 2 - Example Daily Price Pattern (12/31/2015 analysis)



Once the historical regression and daily price pattern analyses are complete, the hourly forecast of MINN.HUB LMPs can be updated using forecast hourly customer demand, hourly wind energy, and monthly natural gas prices. The load, wind, and natural gas price forecasts used in the PLEXOS modeling tool are used for the MINN.HUB energy price forecast such that the hourly LMP price forecast correlates to the modeled load, wind pattern, and gas price in any given database. The mathematical relationship established by the historical regression is applied to the forecast via the regression coefficients and historical daily price pattern by month.

Northern States Power Company Docket No. E002/AA-23-153
Electric Utility - State of Minnesota Petition
MISO Charges (in $1000s) Part B, Attachment 9

	Category	2024 Forecast	
	[PROTECTED DATA BEGINS		
1	Congestion		Part F, Workpaper 5
2	FTR		Part F, Workpaper 5
3	Incremental Transmission losses		Part F, Workpaper 5
4	RSG/RNU		Part F, Workpaper 5
5	ASM		Part F, Workpaper 5
6	**MISO Market Charges TOTAL**		line 24, Part A, Att 1, pg 1
7	MISO Market Purchases from PLEXOS		line 23, Part A, Att 1, pg 1
8	MISO Market Sales from PLEXOS		line 29, Part A, Att 1, pg 1
9	**Net MISO Day 2 and Day 3 costs and revenues**		Lines 6+7+8
	PROTECTED DATA ENDS]		

White Paper: Park Potential profiles for modeling wind and solar generation on the NSP System

Author: Drake Bartlett
January 2023

Introduction

This paper discusses the process used to create Park Potential (PP) profiles of wind and solar generation for Xcel Energy's upper Midwest region.

Annual Expected Park Potential

The Company combined monthly generation and curtailment data to derive the monthly Park Potential for each renewable generation Commercial Pricing Node (CP Node) from January 2018 through November 2022. The monthly Park Potentials were summed on a rolling 12-month basis to derive 48 annual Park Potential values. The Company averaged the 48 annual values to determine the annual expected Park Potential value for each CP Node. For renewable generation without sufficient historic data, the most recent Energy Production Estimate (EPE) from pre-construction developer software or the Annual Committed Energy from the Purchase Power Agreement was used as the annual PP value.

Monthly allocation of annual Park Potential

For new wind plants, the pre-construction developer software uses 30 years' worth of meteorological weather reanalysis data to determine the expected monthly generation expressed as a percentage of the annual EPE. The Company used the average of the monthly percentages from new wind plants to allocate the CP Node annual Park Potential values to each calendar month. For solar plants, the Company calculated the ratio of monthly Park Potential relative to annual Park Potential for each month from the years 2018-2022. Table 1 shows the monthly allocations for wind and solar plants expressed as a percentage of the annual expected Park Potential.

Table 1: Monthly percentage of annual wind and solar plant Park Potential

Month	Wind % Allocation	Solar % Allocation
January	9.1%	3.7%
February	8.2%	5.4%
March	9.1%	9.0%
April	9.4%	10.0%
May	9.1%	11.9%
June	7.7%	13.2%
July	6.3%	13.1%
August	6.1%	11.6%
September	7.7%	9.2%
October	9.1%	6.6%
November	9.2%	3.8%
December	9.0%	2.7%

Hourly allocation of monthly Park Potential

For most wind plants, the Company has wind speed data measured at the turbine anemometers.[1] The Company gathered hourly-averaged wind speed data from 2020 for each wind CP Node and used empirical power conversions specific to those CP Nodes to convert the hourly wind speed to hourly generation. The summed monthly generation for each CP Node was compared to the volume of generation derived from the monthly allocation of the annual Park Potential. A constant wind speed adjustment was made to each hour so that the sum of the hourly generation based on the hourly wind speed data matched the monthly allocation of the annual Park Potential.

For wind generation at CP Nodes without wind speed data, the Company generated a single empirical power conversion derived from the simple average of all wind speed data for each hour in 2021 and the paired sum-of-generation from all CP Nodes without wind speed data. For each of these CP Nodes, the Company calculated the pro rata ratio of the CP Node annual Park Potential relative to the sum of annual Park Potentials for all CP Nodes without wind speed data. A constant wind speed adjustment was applied to the system average wind speed profile for each month so that the resulting generation profile matched the monthly allocation of the sum of annual Park Potentials for all CP Nodes without wind speed data. Each CP Node without wind speed data was assigned their pro-rata share of this hourly generation profile for each month.

[1] The Company has turbine wind speed data for approximately 91 percent of Company-controlled wind generation capacity.

For solar generation, the Company used hourly irradiance and generation data from 2020 for each solar plant and used empirical power conversions to convert the hourly irradiance to hourly generation. The summed monthly generation for each plant was compared to the volume of generation derived from the monthly allocation of the annual PP. An irradiance adjustment was made to each hour in a given month so that the sum of the hourly generation based on the hourly irradiance data matched the monthly allocation of the annual PP.

For plants without historic irradiance or generation data, the Company used 2020 hourly irradiance data for each plant location sourced from the National Solar Radiation DataBase (NSRDB) maintained by the National Renewable Energy Laboratory (NREL). The same process was used to derive the hourly generation profiles for these solar plants as for the existing solar plants in the Company's portfolio of renewable generation.

<u>Wind Maintenance Adjustment</u>
For new and repowered wind farms, an adjustment factor is included to account for warranty, preventative maintenance, daily faults, and other issues common with new wind farms in their first years of operation. **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

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	Date Signed	COD	Termination	Term (yrs)	Counterparty	Hrs Available	MW	Energy Price	Capacity Price	Fuel Type	Not Firm?	Dispatchability	Price Escalation?	RPS/Renewable*Connect Assignment[1]
								[PROTECTED DATA BEGINS					[PROTECTED DATA BEGINS	
CC Calpine	3/11/2004	1/1/2006	7/31/2026	20	Mankato Energy Center LLC	All	375			Gas		Dispatchable		None
CC Calpine II	4/28/2015	6/1/2019	5/31/2039	20	Mankato Energy Center LLC	All	345			Gas		Dispatchable		None
CC LSPower	5/9/1994	10/1/1997	9/30/2027	30	LSP- Cottage Grove, L.P.	All	245.1			Gas		Dispatchable		None
CT Invenergy 1	4/1/2005	4/11/2008	4/10/2025	17	Invenergy Cannon Falls LLC	All	178.5			Oil/Gas		Dispatchable		None
CT Invenergy 2	4/1/2005	4/11/2008	4/10/2025	17	Invenergy Cannon Falls LLC	All	178.5			Oil/Gas		Dispatchable		None
DPC Flambeau	7/1/1963	7/1/1963	1/31/2037	Life of Project	Dairyland Flambeau	All	1.2			Hydro		Must Take		None
Eau Galle	7/31/1991	8/1/1991	7/31/2026	35	Eau Galle Renewable Energy Co. Inc.	All	0.300			Hydro		Must Take		None
Gundersen Lutheran Landfill	12/20/2019	1/11/2022	1/10/2026	4	Gundersen Lutheran	All	1.137			Landfill		Must Take		RPS
Hastings	9/10/1985	10/5/1987	6/30/2033	45	City of Hastings Hydro	All	4.0			Hydro		Must Take		None
HERC	8/1/1986	12/31/1989	12/30/2024	35	Hennepin Energy Resource Recovery (HERC)	All	33.7			Digester		Must Take		None
Part 3	5/1/2015	5/1/2015	4/30/2025	10	Manitoba Hydro Electric Board	6am-10pm, Mon-Fri	Summer: 375, Winter: 325 (Summer = May thru October)			Hydro		Must Take		None
Part 4	5/27/2010	5/1/2021	4/30/2025	5	Manitoba Hydro Electric Board	6am-10pm, Mon-Fri	125			Hydro		Must Take		None
SAF	1/9/2007	12/19/2011	12/18/2031	20	SAF Hydroelectric, LLC	All	9.2			Hydro		Must Take		RPS
Solar Aurora	2/12/2015	12/31/2016	12/30/2036	20	Aurora Distributed Solar	All	100			Solar		Must Take		RPS
Solar Best Power International PV	12/1/2009	5/28/2010	5/27/2030	20	St. John's Solar	All	0.5			Solar		Must Take		RPS
Solar Best Power International PV II	5/11/2015	10/12/2015	10/11/2030	15	School Sisters of Notre Dame Solar Park)	All	0.718			Solar		Must Take		RPS
Solar Dragonfly	6/6/2017	9/11/2018	9/10/2033	15	Dragonfly Solar, LLC	All	0.8			Solar		Must Take		RPS
Solar Marshall	3/3/2015	1/09/2017	5/31/2042	25.5	Marshall Solar, LLC	All	62.25			Solar		Must Take		RPS
Solar North Star	3/6/2015	12/21/2016	12/20/2041	25	North Star Solar PV	All	100			Solar		Must Take		RPS
Solar Slayton	11/3/2010	1/14/2013	1/13/2033	20	Slayton Solar, LLC	All	1.66			Solar		Must Take		RPS
Solar Fillmore County Solar Project (6)	12/5/2022	Target 12/15/2024	18.5 Yrs from COD	18.5	Fillmore County Solar Project, LLC	All	30			Solar		Must Take		Renewable*Connect
Solar Louise Solar Generation Facility (6)	12/5/2022	Target 12/15/2024	18.5 Yrs from COD	18.5	Louise Solar Generation Facility, LLC	All	50			Solar		Must Take		Renewable*Connect
Solar RC Replacement (7)	12/5/2022	Following PUC Approval of the PPAs	12/14/2024	1	Louise Solar Generation Facility & Fillmore County Solar Project	All	80			Solar		Must Take		Renewable*Connect
City of St. Cloud (New PPA)	6/12/2020	11/1/2021	5/31/2041	19.5	The City of St. Cloud	All	Summer: 8.1, Winter: 6.6 (Summer = May thru October)			Hydro		Must Take		None
StPaul CoGen (New PPA) (3)	7/26/2021	1/1/2023	12/31/2024	2	St. Paul Cogeneration	All	25			Biomass		Must Take		RPS
ReNew Hydro	10/31/2011	10/31/2011	5/17/2024	10	ReNew Hydro Power, LLC	All	0.205			Hydro		Must Take		RPS
Wind CBED Adams	10/27/2009	3/9/2011	3/8/2031	20	Adams Wind Generations, LLC	All	19.8			Wind		Must Take		RPS
Wind CBED Big Blue	6/1/2010	12/15/2012	12/14/2032	20	Big Blue Wind Farm, LLC	All	36			Wind		Must Take		RPS
Wind CBED Community Wind South	7/6/2011	12/26/2012	12/25/2032	20	Zephyr Wind, LLC	All	30.75			Wind		Must Take		RPS
Wind CBED Danielson	10/27/2009	3/11/2011	3/10/2031	20	Danielson Wind Farms, LLC	All	19.8			Wind		Must Take		RPS
Wind CBED Ewington (New Repower PPA) (4)	10/28/2020	6/30/2022	6/29/2047	25	Ewington Energy Systems, LLC	All	19.95			Wind		Must Take		RPS
Wind CBED Hilltop	12/12/2007	2/20/2009	2/19/2029	20	Hilltop Power	All	2			Wind		Must Take		RPS
Wind CBED Ridgewind	11/3/2008	1/13/2011	1/12/2031	20	Ridgewind Power Partners LLC	All	25.3			Wind		Must Take		RPS
Wind CBED Roseville	5/12/2009	8/9/2010	8/8/2030	20	Grant County Wind	All	20			Wind		Must Take		RPS
Wind CBED Uilk	11/26/2008	1/15/2010	1/14/2030	20	Uilk Wind Farm, LLC	All	4.5			Wind		Must Take		RPS
Wind CBED Valley View	9/26/2008	11/30/2011	11/29/2031	20	Valley View Transmission, LLC	All	10			Wind		Must Take		RPS
Wind CBED Winona	10/15/2009	10/27/2011	10/26/2031	20	Winona County Wind, LLC	All	1.5			Wind		Must Take		RPS
Wind CBED Woodstock	8/10/2009	6/24/2010	6/23/2030	20	Woodstock Municipal Wind, LLC	All	0.75			Wind		Must Take		RPS
Wind Eastridge	11/13/2003	5/1/2006	4/30/2026	20	Bendwind, LLC DeGreeff DP, LLC DeGreeffpa LLC Groen Wind LLC Hillcrest Wind LLC LarswindLLC Sierra Wind LLC TAIR Windfarm LLC	All	10			Wind		Must Take		RPS
Wind Fenton	9/30/2005	11/13/2007	11/12/2032	25	Fenton Power Partners I, LLC	All	205.5			Wind		Must Take		RPS
									PROTECTED DATA ENDS]				PROTECTED DATA ENDS]	

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

	Date Signed	COD	Termination	Term (yrs)	Counterparty	Hrs Available	MW	Energy Price	Capacity Price	Fuel Type	Not Firm?	Dispatchability	Price Escalation?	RPS/Renewable* Connect Assignment[1]
								[PROTECTED DATA BEGINS					[PROTECTED DATA BEGINS	
Wind Garwin McNeilus	Various	Various	Various	20-25	Bangladesh CS LLC, Brandon Wind LLC, BT Windfarm LLC, Burmese CS, LLC, GarMar Foundation I, LLC/ REAP I, Gar Mar Wind I, LLC, GM Windfarm LLC, Henslin Creek LLC, Indian CS, LLC, McNeilus Windfarm LLC, Salvadoran CS LLC, SG (JCKD) Windfarm LLC, Southeast Asian CS, LLC, Triton Wind LLC, Wasioja Wind LLC, Wilhelm Wind LLC	All	27.5			Wind		Must Take		RPS/Windsource (2)
Wind Geronimo Odell	7/2/2013	7/29/2016	7/28/2036	20	Odell Wind, LLC	All	200			Wind		Must Take		RPS
Wind Lakota	3/26/1997	5/1/2004	4/30/2034	30	Northern Alternative Energy Lakota Ridge LLC	All	11.25			Wind		Must Take		None
Wind Moraine II	11/7/2008	2/18/2009	2/17/2029	10	Moraine Wind II LLC	All	49.5			Wind		Must Take		Renewable*Connect
Wind Norgaard	12/26/2003	5/11/2006	5/10/2026	20	Roadrunner ,I LLC, Salty Dog-I LLC, Wallys Windfarm LLC, Windy Dog I LLC, Breezy Bucks-I & II LLC, Salty Dog II, LLC	All	8.75			Wind		Must Take		RPS
Wind North Shaokatan	2/15/1999	11/1/2003	10/31/2033	30	Autumn Hills LLC, Jack River LLC,Jessica Mills LLC, Julia Hills LLC, Sun River LLC, Tsar Nicholas, LLC	All	13.53			Wind		Must Take		RPS
Wind Phase 2	9/6/1996	12/14/1998	12/13/2028	30	Lake Benton Power Partners LLC (LBI)	All	104.25			Wind		Must Take		RPS
Wind Prairie Rose	6/7/2011	12/11/2012	12/10/2032	20	Prairie Rose Wind, LLC	All	200			Wind		Must Take		RPS
Wind Ruthton	2/15/1999	1/23/2001	1/22/2031	30	Ruthton Ridge LLC, Florence Hills LLC,Hadley Ridge LLC,Hope Creek LLC, Soliloquy Ridge LLC, Spartan Hills LLC,Twin Lake Hills LL, Winter's Spawn LLC	All	15.84			Wind		Must Take		None
Wind Shaokatan	3/26/1997	5/1/2004	4/30/2034	30	Northern Alternative Enrgy Shakotan Hills LLC	All	11.88			Wind		Must Take		RPS
Wind Source Cisco	9/29/2006	5/28/2008	5/27/2028	20	Cisco Wind Energy LLC	All	8			Wind		Must Take		Renewable*Connect
Wind Source Garwin McNeilus	5/1/2005	5/21/2003	4/30/2025	20	Ashland Windfarm LLC, Elsinore Wind LLC, Gar Mar Foundation II / REAP II, Grant Windfarm LLC, Zumbro Windfarm	All	9.25			Wind		Must Take		Renewable*Connect
Wind Source JJN	5/20/2002	12/17/2004	12/16/2029	25	JJN Windfarm, LLC	All	1.5			Wind		Must Take		Renewable*Connect
Wind Source West Ridge	1/31/2002	12/28/2003	12/27/2028	25	Westridge Windfarm LLC, Tofteland Windfarm LLC, TG Windfarm LLC, CG Windfarm LLC, , Fey Windfarm LLC,	All	9.5			Wind		Must Take		RPS/Windsource (2)
Wind Stahl	11/13/2003	1/1/2005	12/31/2024	20	Stahl Wind Energy LLC, Northern Lights Wind LLC, Lucky Wind LLC, Greenback Energy LLC Cartensen Wind LLC	All	8.25			Wind		Must Take		RPS
Wind Tholen	11/17/2003	8/28/2005	8/27/2025	20	Tholen Transmission Projects	All	13.2			Wind		Must Take		RPS
Wind University of Minnesota	4/24/2011	10/26/2011	Evergreen		UMORE Park, LLC	All	2.5			Wind		Must Take		None
Wind Various	Various	Various	Various	30	Agassiz Beach LLC, Metro Wind LLC, Shanes Wind Farm LLC, Carlton College LLC,Kas Brothers Wind LLC, Ed Olsen Wind LLC, Rock Ridge Windfarm LLC, Southridge Windfarm LLC, St.Olaf College, Windvest Windfarm LLC	All	16.34			Wind		Must Take		RPS
Wind Velva	5/10/2004	1/19/2006	1/18/2026	20	Velva Windfarm, LLC	All	11.88			Wind		Must Take		RPS
Wind Westridge	1/31/2002	12/28/2003	Various 2028	25	K-Brink Wind Farm, LLC Bisson Windfarm LLC, Boeve Windfarm LLC, Windcurrents Windfarm, LLC	All	7.6			Wind		Must Take		RPS
Wind Woodstock (5)	9/19/1997	5/1/2004	4/30/2033	30	Woodstock Wind Farm, LLC	All	9.2			Wind		Must Take		RPS
Wind Crown Ridge	3/7/2017	1/10/2020	1/9/2045	25	Crowned Ridge Wind, LLC	All	200			Wind		Must Take		RPS
Wind Clean Energy	3/13/2017	12/19/2019	12/18/2039	20	Glen Ullin Energy Center, LLC	All	106.8			Wind		Must Take		RPS
Wind Dakota Range III	10/29/2018	4/29/2021	4/28/2033	12	DAKOTA RANGE III, LLC	All	153.6			Wind		Must Take		RPS
Wind Deuel Harvest PPA	11/25/2019	10/1/2021	9/30/2036	15	Deuel Harvest Wind Energy, LLC	All	100			Wind		Must Take		Renewable*Connect
Wind Heartland Divide 2 PPA	7/21/2020	4/11/2022	4/10/2047	25	Heartland Divide Wind II, LLC	All	200			Wind		Must Take		Renewable*Connect
									PROTECTED DATA ENDS]				PROTECTED DATA ENDS]	

Notes:

(1) "RPS" indicates compliance with the Renewable Portfolio Standards/Objectives of Minnesota, Wisconsin, North Dakota, and/or South Dakota.
"Renewable*Connect" indicates resource is used for the NSP green pricing program
"None" indicates that the generator owner retains the RECs and the resource is not used for compliance with any Renewable Portfolio Standard/Objectives or green pricing program
(2) The generation from this resource is allocated to RPS compliance and to Windsource. None of the RECs are used for both purposes.
(3) The new St. Paul PPA (Project Skyline) went into effect on Jan 1, 2023 (original PPA terminated 12/31/22)
(4) This is the Ewington Energy Repower PPA. The original PPA terminated 10/4/21. Pricing is the same as original PPA
(5) Woodstock Wind Farm Repowered and Amendment 2 reduced the contracted capacity down from 10.2 MW.
(6) Elk Creek Solar, LLC PPA terminated 12/13/22 and two replacement PPAs were executed on 12/5/22.
(7) Replacement Products and Services from the market during the interim.

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
1	Le Sueur	9/9/2015	0.036	4
2	Lincoln	4/25/2016	0.204	16
3	Ramsey	5/12/2016	0.125	5
4	Hennepin	8/22/2016	0.036	17
5	Chisago	12/14/2016	5	41
6	Dakota	12/14/2016	5	85
7	Chisago	12/15/2016	4	40
8	Carver	12/15/2016	5	624
9	Scott	12/19/2016	3	223
10	Dakota	12/20/2016	5	29
11	Stearns	12/21/2016	5	55
12	Dakota	12/22/2016	5	28
13	Stearns	1/4/2017	3	21
14	Stearns	1/5/2017	3	274
15	Goodhue	1/12/2017	4.86	45
16	Dakota	1/13/2017	5	28
17	Chisago	1/13/2017	3.888	29
18	Dakota	2/13/2017	5	204
19	Goodhue	2/13/2017	4	307
20	Carver	2/28/2017	4.86	31
21	Washington	3/10/2017	0.036	6
22	Wabasha	3/13/2017	3	183
23	Blue Earth	5/31/2017	3	17
24	Redwood	5/31/2017	3	51
25	Winona	5/31/2017	0.25	28
26	Rice	6/30/2017	5	269
27	Dodge	7/18/2017	5	481
28	Washington	7/18/2017	5	200
29	Olmsted	7/19/2017	5	445
30	Kandiyohi	8/14/2017	2	10
31	Pipestone	8/18/2017	2	48
32	Chisago	8/22/2017	3	20
33	Stearns	8/24/2017	2	26
34	Chippewa	8/29/2017	2	15
35	Dakota	8/31/2017	5	44
36	Pope	9/13/2017	5	46
37	Stearns	9/13/2017	2.188	25
38	Stearns	9/13/2017	4.86	45
39	Lincoln	9/14/2017	0.2	20

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
40	Sherburne	9/22/2017	5	177
41	Dodge	9/27/2017	4	34
42	Benton	9/29/2017	2	27
43	McLeod	10/25/2017	3	44
44	Chippewa	10/25/2017	3	56
45	Hennepin	10/25/2017	5	26
46	McLeod	10/26/2017	5	145
47	Pipestone	10/30/2017	5	60
48	Stearns	10/30/2017	3	37
49	Benton	10/30/2017	5	37
50	Wright	11/3/2017	5	1118
51	Stearns	11/9/2017	5	45
52	Wright	11/13/2017	5	1081
53	Stearns	11/16/2017	4	165
54	Nicollet	11/20/2017	5	32
55	Blue Earth	11/20/2017	5	53
56	Scott	11/30/2017	4.69	40
57	Scott	11/30/2017	0.7	6
58	Dakota	11/30/2017	2.7	126
59	Rice	11/30/2017	5	203
60	Stearns	12/13/2017	5	45
61	Chisago	12/13/2017	5	30
62	Carver	12/15/2017	5	60
63	Chisago	12/18/2017	5	25
64	Dodge	12/18/2017	5	79
65	Scott	12/20/2017	2.991	24
66	Carver	12/21/2017	4.361	45
67	Renville	12/28/2017	3	66
68	Washington	1/10/2018	5	80
69	Carver	1/16/2018	3	19
70	Le Sueur	1/18/2018	3	17
71	Dakota	1/23/2018	4.95	45
72	Wabasha	1/29/2018	4	23
73	Pipestone	1/31/2018	4.7	89
74	Sherburne	2/12/2018	3.25	349
75	Rice	2/14/2018	0.998	157
76	Le Sueur	2/23/2018	3	46
77	Carver	2/26/2018	1.996	310
78	Waseca	2/26/2018	5	68

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
79	Rice	2/28/2018	5	30
80	Le Sueur	2/28/2018	5	52
81	Washington	2/28/2018	4	682
82	Faribault	3/2/2018	1.84	21
83	Rice	3/2/2018	3	21
84	Steele	3/5/2018	3.4	227
85	Carver	3/6/2018	3	18
86	Chisago	3/13/2018	5	25
87	Carver	3/14/2018	0.998	143
88	Sherburne	3/14/2018	5	41
89	Pope	3/15/2018	5	464
90	Chippewa	3/25/2018	4	42
91	Benton	3/25/2018	2	16
92	Scott	3/28/2018	4.95	70
93	Goodhue	4/12/2018	0.8	137
94	Washington	4/13/2018	3	25
95	Pope	4/19/2018	3	292
96	Washington	4/20/2018	5	30
97	Goodhue	4/26/2018	0.998	130
98	Chisago	4/30/2018	3	18
99	Stearns	4/30/2018	5	55
100	Sherburne	4/30/2018	4	42
101	Goodhue	5/11/2018	1	26
102	Renville	5/16/2018	1	23
103	Renville	5/17/2018	1	20
104	Goodhue	5/22/2018	1	9
105	Blue Earth	5/30/2018	1	9
106	Steele	6/5/2018	1	6
107	Hennepin	6/6/2018	0.18	31
108	Lyon	6/15/2018	3	47
109	Rice	6/20/2018	1	18
110	Le Sueur	6/29/2018	3	21
111	Sherburne	6/29/2018	5	35
112	Watonwan	7/2/2018	0.25	21
113	Sherburne	7/13/2018	5	50
114	Washington	7/16/2018	2.5	15
115	Steele	7/18/2018	1	6
116	Goodhue	7/19/2018	5	37
117	Dakota	7/27/2018	5	40

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
118	Goodhue	7/30/2018	2	18
119	Chisago	8/1/2018	1	25
120	DOUGLAS	8/2/2018	5	277
121	Le Sueur	8/6/2018	5	443
122	Blue Earth	8/7/2018	3.54	513
123	Chisago	8/9/2018	5	34
124	Wright	8/14/2018	0.972	5
125	Benton	8/14/2018	4.95	35
126	Carver	8/16/2018	4	1240
127	Wright	8/27/2018	5	440
128	Chisago	8/30/2018	1	10
129	Washington	9/4/2018	5	1346
130	Washington	9/7/2018	0.75	93
131	Goodhue	9/14/2018	1	11
132	Dakota	9/17/2018	0.75	9
133	Goodhue	9/19/2018	1	23
134	Waseca	9/27/2018	1	5
135	Chisago	9/28/2018	1	49
136	Chisago	9/28/2018	1	7
137	Hennepin	9/28/2018	0.32	25
138	Blue Earth	10/16/2018	5	38
139	Wright	10/17/2018	4	29
140	McLeod	10/25/2018	1	5
141	Waseca	10/25/2018	1	5
142	Washington	10/29/2018	4.875	45
143	Benton	10/30/2018	1	10
144	Waseca	11/1/2018	1	10
145	Chippewa	11/14/2018	1	139
146	Kandiyohi	11/14/2018	1	25
147	Pope	11/16/2018	1	17
148	Sherburne	11/16/2018	1	5
149	Chisago	11/26/2018	1	11
150	Chisago	11/27/2018	1	15
151	Wright	11/28/2018	5	35
152	Scott	11/28/2018	0.823	8
153	Hennepin	11/28/2018	0.527	77
154	Scott	11/28/2018	1	8
155	Chisago	11/28/2018	1	9
156	Chisago	11/28/2018	1	12

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
157	Chisago	11/29/2018	1	13
158	Sherburne	12/3/2018	5	55
159	Chisago	12/7/2018	1	7
160	Sherburne	12/10/2018	4.8	45
161	Chisago	12/11/2018	0.5	20
162	Stearns	12/17/2018	1	62
163	Benton	12/17/2018	1	9
164	Benton	12/17/2018	1	7
165	Chippewa	12/18/2018	1	13
166	Le Sueur	12/19/2018	1	11
167	Murray	12/20/2018	1	8
168	Murray	12/20/2018	1	11
169	Yellow Medicine	12/21/2018	5	136
170	Ramsey	1/8/2019	0.54	5
171	Dodge	1/9/2019	1	11
172	Hennepin	1/11/2019	5	649
173	Meeker	1/23/2019	0.76	9
174	Stearns	1/28/2019	0.324	9
175	Nicollet	1/31/2019	1	7
176	Waseca	2/13/2019	1	11
177	Chisago	2/27/2019	2	18
178	Stearns	3/4/2019	0.72	9
179	Stearns	3/4/2019	1	12
180	Blue Earth	3/5/2019	0.24	11
181	McLeod	3/12/2019	3	87
182	Washington	3/22/2019	1	198
183	Stearns	3/25/2019	1	10
184	Wabasha	3/26/2019	0.85	128
185	Pope	3/26/2019	1	17
186	Sherburne	3/28/2019	5	89
187	Pope	3/28/2019	1	16
188	Renville	3/29/2019	1	15
189	Goodhue	4/11/2019	5	526
190	Wright	4/15/2019	5	1031
191	Stearns	4/16/2019	1	12
192	Chisago	4/22/2019	3	238
193	Washington	4/22/2019	1	185
194	Rice	4/30/2019	1	7
195	Carver	5/1/2019	1	6

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
196	Lyon	5/3/2019	1	12
197	Benton	5/13/2019	5	276
198	Dodge	5/15/2019	1	101
199	Dodge	5/15/2019	0.4	67
200	Kandiyohi	5/21/2019	1	9
201	Chisago	5/21/2019	1	8
202	Wright	5/31/2019	5	170
203	Stearns	6/3/2019	5	40
204	Dakota	6/7/2019	5	35
205	Dakota	6/7/2019	5	30
206	Sibley	6/14/2019	3.25	66
207	Stearns	6/18/2019	3	42
208	Freeborn	6/18/2019	0.25	37
209	Chisago	7/3/2019	1	13
210	Carver	7/22/2019	1	8
211	Scott	7/24/2019	0.598	65
212	Carver	7/25/2019	1	8
213	Sherburne	7/26/2019	3	31
214	Hennepin	7/30/2019	0.18	20
215	Sherburne	7/31/2019	0.996	148
216	Dakota	8/6/2019	1	385
217	Rice	8/8/2019	1	47
218	Scott	8/13/2019	1	12
219	Chisago	8/16/2019	0.998	200
220	Stearns	8/16/2019	1	158
221	Stearns	8/16/2019	1	156
222	Wabasha	8/20/2019	1	160
223	Wabasha	8/20/2019	1	143
224	Winona	8/21/2019	5	209
225	Winona	8/22/2019	1	124
226	Wabasha	8/22/2019	1	125
227	Winona	8/22/2019	1	99
228	Chippewa	8/26/2019	1	22
229	Carver	8/29/2019	1	6
230	McLeod	8/30/2019	1	12
231	Chisago	9/3/2019	1	5
232	Waseca	9/6/2019	1	11
233	Olmsted	9/9/2019	1	6
234	Pope	9/11/2019	1	11

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
235	Pope	9/11/2019	1	9
236	Hennepin	9/18/2019	0.96	188
237	Rice	9/18/2019	1	13
238	Blue Earth	9/24/2019	0.62	35
239	Goodhue	9/27/2019	4.4	51
240	Blue Earth	9/27/2019	0.62	28
241	Rice	10/9/2019	1	16
242	Stearns	10/23/2019	1	25
243	Stearns	10/25/2019	4.75	77
244	Sherburne	10/29/2019	1	13
245	Scott	10/30/2019	0.4	5
246	Waseca	11/18/2019	0.996	152
247	Sherburne	11/26/2019	1	14
248	Stearns	12/3/2019	1	13
249	Meeker	12/11/2019	1	41
250	Dakota	12/11/2019	1	15
251	DOUGLAS	12/11/2019	1	25
252	Meeker	12/13/2019	1	199
253	Rice	12/13/2019	1	8
254	Pope	12/16/2019	1	8
255	Stearns	12/16/2019	1	9
256	Nicollet	12/18/2019	1	181
257	Blue Earth	12/18/2019	1	167
258	McLeod	12/18/2019	1	162
259	Chisago	12/19/2019	1	12
260	Stearns	12/23/2019	1	15
261	Sherburne	12/23/2019	1	14
262	Sherburne	12/26/2019	1	9
263	Stearns	12/27/2019	1	202
264	DOUGLAS	12/27/2019	1	181
265	McLeod	12/27/2019	1	9
266	Renville	12/30/2019	1	13
267	Sherburne	12/30/2019	0.94	7
268	Goodhue	12/31/2019	0.59	12
269	Winona	1/3/2020	1	165
270	Winona	1/3/2020	1	177
271	Stearns	1/13/2020	1	12
272	Rice	1/14/2020	1	9
273	Dakota	1/15/2020	1	7

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
274	Meeker	1/17/2020	1	6
275	Winona	2/12/2020	1	21
276	Goodhue	2/13/2020	1	26
277	Pope	2/17/2020	1	12
278	Hennepin	2/17/2020	0.29	6
279	Rice	2/20/2020	1	9
280	Goodhue	2/26/2020	1	19
281	Pope	2/26/2020	1	13
282	Waseca	2/27/2020	1	8
283	Goodhue	2/28/2020	1	210
284	Goodhue	2/28/2020	1	187
285	Sherburne	2/28/2020	1	20
286	Waseca	3/4/2020	1	9
287	Washington	3/9/2020	3	15
288	Goodhue	3/9/2020	1	202
289	Rice	3/20/2020	1	9
290	Sibley	3/26/2020	1	13
291	Dakota	3/26/2020	1	9
292	Sibley	4/3/2020	1	18
293	Olmsted	4/3/2020	1	8
294	Dodge	4/7/2020	1	12
295	DOUGLAS	4/9/2020	1	16
296	Olmsted	4/13/2020	1	11
297	Olmsted	4/16/2020	1	9
298	Rice	4/24/2020	0.96	108
299	Scott	4/27/2020	3	773
300	Rice	4/27/2020	1	15
301	Goodhue	4/30/2020	1	27
302	Chisago	5/19/2020	1	9
303	Benton	5/20/2020	1	10
304	Stearns	5/21/2020	1	5
305	Dodge	5/21/2020	1	10
306	Carver	5/28/2020	1	51
307	Pope	5/30/2020	1	25
308	Dakota	6/2/2020	1	235
309	Dakota	6/4/2020	1	236
310	Waseca	6/16/2020	1	8
311	Rice	6/17/2020	2	37
312	Winona	6/24/2020	1	16

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
313	Winona	6/24/2020	1	37
314	Benton	7/10/2020	1	20
315	Rice	7/13/2020	5	84
316	Rice	7/20/2020	4	105
317	McLeod	7/20/2020	4	32
318	Nicollet	7/30/2020	1	9
319	Goodhue	7/30/2020	1	16
320	Stearns	7/31/2020	1	14
321	Wright	7/31/2020	1	24
322	Le Sueur	7/31/2020	1	7
323	Sherburne	7/31/2020	1	26
324	Goodhue	8/18/2020	1	10
325	Sherburne	9/1/2020	1	10
326	Redwood	9/14/2020	0.86	30
327	Chisago	9/14/2020	1	9
328	Waseca	9/15/2020	1	13
329	Chippewa	9/16/2020	1	20
330	Redwood	9/16/2020	1	29
331	Waseca	9/21/2020	1	11
332	Steele	9/22/2020	1	14
333	Nicollet	9/22/2020	1	10
334	Washington	9/28/2020	1	18
335	Redwood	9/28/2020	1	24
336	Freeborn	9/29/2020	1	23
337	Wright	10/1/2020	1	8
338	Dodge	10/6/2020	1	13
339	Dakota	10/6/2020	1	6
340	Clay	10/8/2020	1	38
341	Clay	10/8/2020	1	35
342	Clay	10/8/2020	1	36
343	Clay	10/8/2020	1	29
344	Nicollet	10/8/2020	1	24
345	Benton	10/14/2020	1	8
346	Rice	10/15/2020	0.7	7
347	Kandiyohi	10/19/2020	1	14
348	Kandiyohi	10/19/2020	1	12
349	Washington	10/20/2020	1	81
350	Clay	10/21/2020	1	31
351	Goodhue	10/26/2020	1	8

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
352	Waseca	10/27/2020	1	9
353	Renville	10/29/2020	1	14
354	Freeborn	10/30/2020	1	57
355	Chippewa	10/30/2020	1	23
356	Benton	11/3/2020	1	87
357	Dakota	11/4/2020	1	10
358	Goodhue	11/5/2020	1	19
359	Dodge	11/9/2020	1	17
360	Olmsted	11/9/2020	1	12
361	Sherburne	11/10/2020	1	10
362	Dodge	11/16/2020	1	7
363	Rice	11/19/2020	1	10
364	Goodhue	11/19/2020	1	8
365	Dodge	11/23/2020	1	12
366	Winona	11/30/2020	1	19
367	Stearns	12/1/2020	1	11
368	Renville	12/4/2020	1	11
369	McLeod	12/4/2020	1	8
370	Lyon	12/7/2020	1	29
371	Stearns	12/9/2020	1	14
372	Chisago	12/9/2020	1	6
373	Carver	12/10/2020	1	87
374	Chisago	12/11/2020	1	8
375	Pope	12/14/2020	1	9
376	Pope	12/14/2020	1	7
377	Stearns	12/16/2020	1	7
378	Nicollet	12/17/2020	1	8
379	Pope	12/21/2020	1	17
380	Rice	12/21/2020	1	78
381	Pope	12/28/2020	1	25
382	McLeod	12/30/2020	1	34
383	Dodge	1/4/2021	1	18
384	Dodge	1/4/2021	1	34
385	Waseca	1/6/2021	1	16
386	Le Sueur	1/28/2021	1	13
387	Kandiyohi	2/2/2021	1	9
388	Blue Earth	3/2/2021	1	10
389	Stearns	3/22/2021	0.86	26
390	Rice	3/23/2021	0.83	10

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
391	Rice	3/25/2021	1	9
392	Redwood	3/31/2021	1	6
393	Redwood	3/31/2021	0.86	12
394	Waseca	4/7/2021	1	13
395	Benton	4/21/2021	1	8
396	Benton	4/22/2021	1	6
397	Sherburne	6/2/2021	1	242
398	Washington	6/8/2021	1	216
399	Steele	6/16/2021	1	9
400	Rice	7/9/2021	1	202
401	Wright	7/13/2021	4	230
402	Dodge	7/13/2021	0.78	24
403	Pope	7/20/2021	1	92
404	Renville	7/20/2021	1	90
405	Renville	7/21/2021	1	156
406	McLeod	7/21/2021	1	99
407	Chisago	7/21/2021	1	8
408	Chisago	8/3/2021	1	8
409	Chisago	8/3/2021	1	9
410	Pipestone	8/5/2021	1	42
411	Goodhue	8/13/2021	1	6
412	Benton	8/19/2021	0.7	110
413	Pope	9/1/2021	1	100
414	Le Sueur	9/2/2021	1	13
415	Pope	9/23/2021	1	8
416	Goodhue	9/28/2021	1	193
417	Le Sueur	9/29/2021	1	13
418	McLeod	10/12/2021	1	115
419	Le Sueur	10/22/2021	1	18
420	Blue Earth	11/30/2021	1	12
421	Renville	11/30/2021	1	71
422	Goodhue	11/30/2021	1	47
423	Chisago	12/8/2021	1	8
424	Chisago	12/8/2021	1	9
425	Chisago	12/16/2021	1	6
426	Wright	12/22/2021	1	54
427	Nicollet	2/16/2022	1	141
428	Waseca	3/10/2022	1	172
429	Waseca	4/20/2022	1	7

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
430	Yellow Medicine	4/28/2022	1	18
431	Renville	5/12/2022	1	70
432	Wabasha	5/31/2022	1	182
433	Blue Earth	6/1/2022	1	7
434	Winona	6/9/2022	1	151
435	Blue Earth	6/9/2022	1	54
436	Benton	6/10/2022	1	131
437	McLeod	8/5/2022	0.427	25
438	Dodge	8/11/2022	1	188
439	Redwood	8/24/2022	1	75
440	Dodge	8/26/2022	0.48	7
441	Chisago	8/31/2022	1	213
442	Lyon	9/8/2022	1	90
443	Dodge	9/9/2022	1	126
444	McLeod	9/28/2022	1	64
445	Renville	10/13/2022	1	30
446	Hennepin	11/10/2022	0.125	0
447	Renville	11/29/2022	1	0
448	Chippewa	12/6/2022	1	0
449	Murray	12/8/2022	1	0
450	DOUGLAS	12/9/2022	0.453	0
451	Ramsey	12/9/2022	0.25036	0
452	Le Sueur	12/9/2022	1	0
453	Sherburne	12/12/2022	1	0
454	Chippewa	12/13/2022	1	0
455	Sibley	12/14/2022	1	0
456	Blue Earth	12/19/2022	1	0
457	Renville	12/19/2022	1	0
458	Wabasha	12/20/2022	1	0
459	Renville	12/20/2022	1	0
460	Goodhue	12/22/2022	1	0
461	Winona	12/28/2022	1	0

* Data represents subscriptions through November. Projects completed in December had yet to receive bill credits are therefore are not yet counted here.

XCEL ENERGY, INC.
NSP PEAK DEMAND AND ELECTRIC CONSUMPTION FORECAST

Forecast Methodology

Overall Methodological Framework

Xcel Energy prepares its forecast by major customer class and jurisdiction, using a variety of statistical and econometric techniques. The NSP System serves five jurisdictions. Minnesota, North Dakota and South Dakota are served by Northern States Power Company (NSPM). Wisconsin and Michigan are served by Northern States Power Company, a Wisconsin corporation (NSPW). The NSPM and NSPW Systems operate as an integrated system. The forecast is referred to as the 2023v1.0 Forecast (completed in March 2023).

Specific Analytical Techniques

1. ***Econometric Analysis*** Xcel Energy uses econometric analysis to develop jurisdictional MWh sales forecasts at the customer meter for the following sectors:
   a. Residential without Space Heating;
   b. Residential with Space Heating;
   c. Small Commercial and Industrial;
   d. Large Commercial and Industrial (Minnesota);
   e. Public Street and Highway Lighting (Minnesota);
   f. Other Sales to Public Authorities (Minnesota);
   g. Total System MW Demand Forecast.
2. ***Trend analysis*** is used for "Other" sectors, which includes Public Street and Highway Lighting (all states except Minnesota), Other Sales to Public Authorities (Michigan, North Dakota and Wisconsin), Interdepartmental (Michigan, Minnesota and Wisconsin), and Large Commercial and Industrial (Michigan, North Dakota, South Dakota, and Wisconsin).
3. ***Loss Factor Methodology*** Loss factors by jurisdiction are used to convert the sales forecasts into system energy requirements (at the generator).
4. ***Judgment*** is inherent to the development of any forecast. Whenever possible, Xcel Energy uses quantitative models to structure its judgment in the forecasting process.

The sales forecasts are estimates of MWh levels measured at the customer meter. They do not include line or other losses. The various jurisdictional class forecasts were summed to yield the total system sales forecast. Native energy requirements are measured at the generator and include line and other losses. Xcel Energy created the native energy requirements based on the sales forecasts. Monthly loss factors for each jurisdiction, developed based on average historical losses, were applied to the sales forecasts to calculate total losses. The sum of the MWh sales, Company Use, and losses equals native energy requirements. The native energy requirements, along with peak producing weather and binary variables, then were used as independent variables within an econometric model to forecast MW peak demand for the NSP System.

The econometric models were developed using the MetrixND[1] modeling software and are identified as outlined below.

Models Used

1. ***Residential Econometric Models*** Residential sales are divided into with space heating and without space heating customer classes for each NSPM jurisdiction. NSPW jurisdictions only have a total Residential customer class. Regression models using historical data are developed for each Residential sector. A variety of independent variables were used in the models, including:
   - Real Personal Income or Real Personal Income per Capita for the respective jurisdiction;
   - Average price (reported revenues/reported sales) for the respective jurisdiction;
   - Gross Metro Product for the respective jurisdiction;
   - Total population for the respective jurisdiction;
   - Average price of West Texas Intermediate crude oil;
   - Google Mobility Index for duration of time at residential locations;
   - Actual heating (HDD) and temperature humidity index (THI) degree days;
   - Number of customers;
   - Number of monthly billing days;
   - Month specific binary variables;
   - Other binary and or trend variables;
2. ***Small Commercial and Industrial Econometric Models*** The models are regressions using historical data. The models include a combination of variables, such as:
   - Number of Small Commercial and Industrial customers;
   - Gross State/Metro Product for the respective jurisdiction;

[1] Metrix ND 4.7, Copyright © 1997-2016, Itron, Inc., http://www.itron.com

- Employment for the respective jurisdiction;
- Google Mobility Index for duration of time at workplace locations;
- Actual heating (HDD) and temperature humidity index (THI) degree days;
- Number of monthly billing days;
- Month specific binary variables;
- Other binary and or trend variables;

3. ***Large Commercial and Industrial Econometric Models*** The model is a regression using historical data and a combination of variables, such as:
    - Industrial Production Index;
    - Number of monthly billing days;
    - Month specific binary variables;
    - Other binary variables;
4. ***Others*** This sector includes Public Street and Highway Lighting (PSHL), Sales to Public Authorities (OSPA) and Interdepartmental (IDS) sales. Because this class represents a very small portion of the total sales, trend analysis is used, and very little growth is forecasted. Exceptions to this are the Minnesota Street Lighting and Other Public Authority classes. The regression models for Minnesota Street Lighting sales and Minnesota Other Public Authority sales use historical data and a combination of variables, such as:
    - Population for the respective jurisdiction;
    - Gross Metro Product for the respective jurisdiction;
    - Number of monthly billing days;
    - Month specific binary variables;
    - Other binary and or trend variables;
5. ***Peak Demand Model*** An econometric model is developed to forecast base peak demand for the entire planning period. The model includes a combination of variables, such as:
    - Weather normalized native energy requirements adjusted for the impacts of historical DSM programs and without adjustments for future DSM, future distributed solar generation behind the customer's meter, and future electric vehicle charging;
    - Peak producing weather by month weighted by customer counts;
    - Binary variables.

Methodology Strengths and Weaknesses

The strength of the process Xcel Energy uses for this forecast is the richness of the information obtained during the analysis. Xcel Energy's econometric forecasting models are based on sound economic and statistical theory. Historical modeling and forecast drivers are based on economic and demographic variables that are easily measured and analyzed. The use of models by class and jurisdiction gives greater insight into how the NSP System is growing, thereby providing better information for decisions to be made in the areas of generation, transmission, marketing, conservation, and load management.

With respect to accuracy, forecasts of this duration are inherently uncertain. Planners and decision makers must be keenly aware of the inherent risk that accompanies long-term forecasts. They must also develop plans that are robust over a wide range of future outcomes.

Modeling Data

Xcel Energy uses internal and external data to create its MWh sales and MW peak demand forecast.

Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. Historical coincident net peak demand data is obtained through company records. The load management estimates are added to the net peak demand to derive the base peak demand.

Monthly weather data is collected for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire metropolitan areas. The heating degree-days and THI degree-days are calculated internally based on this weather data.

Economic and demographic data is obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically, they are accessed from IHS Markit, and reflect the most recent values of those series at the time of modeling.

Demand-Side Management Programs

The Company sponsors demand-side management ("DSM") programs in the Minnesota and South Dakota jurisdictions. There are no Company-sponsored DSM programs in the North Dakota, Michigan, or Wisconsin jurisdictions. For Minnesota and South Dakota, the regression model results for the Residential and Commercial and Industrial classes are reduced to account for the expected impacts of DSM programs.

The DSM methodology utilizes a transparent method for projecting the impacts of energy efficiency and load management on sales forecasts. There are three distinct steps to this process:

- Collect and calculate historical and current effects of DSM on observed sales;
- Project the forecast using observed data with the impact of DSM removed (i.e. increase historical sales to show hypothetical case without DSM);
- Adjust the forecast to show the impact of all planned DSM in future years.

The first step involves collecting data involving any measure that would cause an impact on the time period utilized in the sales forecast. In the 2023V1 modeling, the Company used the time period from 2008 to December 2022 and therefore the historical DSM would include any measure that results in decreased sales in any (or all) years from 2008 through December 2022. Since the vast majority of DSM measures have a lifetime greater than one year (exceptions include but are not limited to behavioral energy savings programs), the impact on sales will include the year that a measure is installed as well as any years that follow until the measure has reached the end of its useful life. For example, a residential lighting measure that was installed in 2008 and has a life of 6 years will result in a sales reduction from 2008 to 2013 (6 full calendar years). Though a measure may be installed in June of 2008 and would persist until May of 2013, the Company believes that the simplifying case in which all measures are installed for the entire calendar year is sufficient.

Due to the wide variation of measures available to customers, the Company sums the savings for each year by DSM program to optimize the level of detail and depth of history included in the model. Achievement data are from the approved Conservation Improvement Program (CIP) Status Reports filed annually for each year since 1996.

Adjustments for distributed solar generation

In response to the establishment of a Solar Energy Standard (SES) by the Minnesota Legislature an increased emphasis has been placed on distributed solar generation. A forecast of the expected impact on demand and energy has been developed based on new programs designed to meet goals established for the SES. Impacts of customer sited behind-the-meter solar installations on the NSP system were extracted from this forecast and used to develop adjustments to reduce the class level sales for Minnesota and the NSP System peak demand forecast.

Xcel has calculated and metered the historical impact of distributed solar generation on customer sales and peak demands.

Once the total impact of DSM in effect and distributed solar generation is calculated for each year, a hypothetical sales data set is created. This series consists of the observed sales from 2008 through December 2022 plus the effective DSM calculated for all DSM measures installed in that year as well is achieved savings from programs in prior years that are still within the useful measure life, plus the historical distributed solar generation.

In the second step, the hypothetical sales data is used to generate a sales forecast that has entirely excluded the impacts of Company-sponsored DSM and distributed solar generation. It is important to note that customer-initiated DSM or DSM due to codes and standards (naturally occurring DSM) is not calculated as part of the CIP. The methodology to account for codes and standards changes is described below.

In the third step, once the sales forecast based on hypothetical sales has been generated, the Company adjusts the forecast to account for future DSM and future distributed solar generation. The forecast of future distributed solar generation is developed by Xcel Energy's Load Research Department. A monthly forecast of the impact of new DSM programs (excluding Saver's Switch) is developed by Xcel Energy's DSM Strategy and Policy Department. The future DSM sales volumes are combined with the continuing impacts of historical DSM measures and future solar generation and used to reduce the class level sales forecasts that result from the regression modeling process to determine the DSM and solar-adjusted sales. Impacts from all program installations through December 2022 are assumed to be imbedded in the historical data, so only new program installations and the continuing impact of historical programs are included in the DSM-solar generation adjustment. The source for Company-sponsored DSM adjustments is based on the CIP Plan in effect at the time of the forecast.

The Company's Saver's Switch program results in short-term interruptions of service designed to reduce system capacity requirements rather than permanent reductions in energy use, so it is not considered here.

Data Adjustments and Assumptions

1. Weather Adjustments. Xcel Energy adjusts the monthly weather data used in the sales models to reflect billing schedules. Therefore, the monthly weather data corresponds exactly with the billing month schedule.

2. Economic Adjustments. All price data and related economic series are deflated to 2012 constant dollars.

3. Demand Forecast Wholesale Adjustment. An adjustment to account for terminating firm wholesale customer contracts was incorporated into the development of the peak demand forecast. Estimated historical coincident peak demand and energy for all firm wholesale customers were removed from the regression model data to create a consistent data series for retail demand and energy.

4. The Large Commercial and Industrial Sales forecast for Minnesota has been adjusted to account for planned changes in production and/or customer owned generation for several large customers.

5. Electric Vehicle Adjustments. The penetration of electric vehicles in Xcel Energy's service territory has been increasing over the past few years and is expected to continue increasing. Because this trend of increasing electric vehicle penetration is expected to continue, the Residential sales forecasts have been adjusted for to account for future electricity usage from home charging of electric vehicles. In addition, the Small Commercial and Industrial and Large Commercial and Industrial sales forecasts have been adjusted to account for future electricity usage from the charging of medium-duty and heavy-duty electric vehicles.

   Because the peak demand forecast was developed with an energy forecast that had the adjustments for electric vehicle charging removed, the peak demand forecast includes a post-modeling adjustment to account for future electric vehicle charging impacts at the system peak. The electric vehicle assumptions for the expected MWh sales impacts and MW peak demand impacts were developed by Xcel Energy's Risk Management department.

6. COVID Pandemic Assumptions. The COVID-19 pandemic has had an impact on Xcel Energy sales. The Residential class has experienced an increase in sales resulting from an increase in working-from-home and social distancing measures. Over the next few years Residential sales are expected to experience declining sales

growth as more employees return to the workplace. Residential regression models include a Google Mobility Index variable which measure the duration of time at residential locations relative to pre-COVID-19 pandemic conditions. This variable quantifies the sales impact of increase time spent at home due to the COVID-19 pandemic. Conversely, the Small Commercial and Industrial customer class has experienced a sharp decline in sales resulting from pandemic related economic weakness and business shutdowns. Recovery from this downturn is expect with Small Commercial and Industrial and Large Commercial and Industrial sales growth over the next few years. This recovery will be driven by the economic explanatory variables in the Small Commercial and Industrial regression models and a Gooogle Mobility Index variable which measure the duration of time at workplace locations relative to pre-COVID-19 pandemic conditions. . The COVID-19 pandemic impacts on the peak demand forecast are driven by the energy forecast.

Assumptions and Special Information

The data used in Xcel Energy's forecasting process has already been discussed in a general way. Descriptions and citations of sources for the data sets have been mentioned within this documentation under different sections.

Xcel Energy believes that its process is a reasonable and practical one to use as a guide for its future energy and load requirements. The underlying assumptions used to prepare Xcel Energy's median forecast are as follows:

1. Demographic Assumption. Population or household projections are essential in the development of the long-range forecast. The forecasts of customers are derived from population and household projections provided by IHS Markit, and reviewed by Xcel Energy staff. Xcel Energy customer growth mirrors demographic growth over the forecast period.

2. Weather Assumption. Xcel Energy assumes "normal" weather in the forecast horizon. Normal weather is defined as the average weather pattern over the 20-year period from 2003-2022. The variability of weather is an important source of uncertainty. Xcel Energy's energy and peak demand forecasts are based on the assumption that the normal weather conditions will prevail in the forecast horizon. Weather-related demand uncertainties are not treated explicitly in this forecast.

3. Loss Factor Assumptions. The loss factors are important to convert the sales forecast to energy requirements. Xcel Energy uses regression modeling to analyze and line losses for each jurisdiction and projects a typical year's loss factor.

Former AAA	Description	Docket or Rule	April 30, 2021 Annual Forecast of Rates	March 1, 2023 Annual True-Up Filing
Part D, Section 1 and all Schedules	Policies and Actions: Fuel Procurement	Rule 7825.2800	Part D, Attachment 1	Part D, Attachment 1
D-1, Schedule 1	Nuclear Fuel Component of Service	Rule 7825.2800	Part D, Attachment 2	Part D, Attachment 2
D-1, Schedule 2	Coal Contracts	Rule 7825.2800	Part D, Attachment 3	Part D, Attachment 3
D-1, Schedule 3	Transportation & Related Services Contracts	Rule 7825.2800	Part D, Attachment 4	Part D, Attachment 4
D-1, Schedule 4	Wood and RDF Contracts	Rule 7825.2800	Part D, Attachment 5	Part D, Attachment 5
D-1, Schedule 5	Cost Changes	Rule 7825.2800	Part D, Attachment 6	Part D, Attachment 6
Part D, Section 2	Policies and Actions: Dispatching Policies and Procedures	Rule 7825.2800	Part D, Attachment 7	Part D, Attachment 7
Part D, Section 3	Policies and Actions: Fuel Supply	Rule 7825.2800	Part D, Attachment 8	Part D, Attachment 8
Part D, Section 4	Policies and Actions: Conservation and Load Management Policy	Rule 7825.2800	Part D, Attachment 9	Part D, Attachment 9
Part D, Section 5	Policies and Actions: Other Actions to Minimize Costs	Rule 7825.2800	Part D, Attachment 10	Part D, Attachment 10
Part E, Section 1	Annual Report of Automatic Adjustment Charges: Base Cost of Fuel	Rule 7825.2810; Docket 04-1279	Part A, Attachment 1 and discussed in Petition	Report Narrative
Part E, Section 2	Annual Report of Automatic Adjustment Charges: Billing Adjustment Amounts Charged to Customers for Each Type of Energy Cost	Rule 7825.2810; Docket 04-1279	Discussed in Petition	Part A
Part E, Section 3	Annual Report of Automatic Adjustment Charges: Total Cost of Fuel Delivered to Customers	Rule 7825.2810; Docket 04-1279	Discussed in Petition	Part A
Part E, Section 4	Annual Report of Automatic Adjustment Charges: Revenue Collected from Customers for Energy Delivered	Rule 7825.2810; Docket 04-1279	Discussed in Petition	Part A
Part E, Section 5	Annual Report of Automatic Adjustment Charges: Monthly Fuel Clause Adjustment	Rule 7825.2810; Docket 04-1279	Part A, Attachment 1 and discussed in Petition	Part A, Attachment 4
Part F, Schedule 1	Memo Engaging Auditor	Rule 7825.2820	NA	Part E, Attachment 1
Part F, Schedule 2	Independent Auditor’s Report	Rule 7825.2820	NA	Part E, Attachment 2
Part G, Schedule 1	5-Year Fuel Cost Forecast – Per Unit Summary	Rule 7825.2830	Part A, Attachment 1 Part E, Attachment 1	NA
Part G, Schedule 2	5-Year Fuel Cost Forecast – Cost Summary	Rule 7825.2830	Part A, Attachment 2 Part E, Attachment 2	NA
Part G, Schedule 3	5-Year Fuel Cost Forecast – Energy Summary	Rule 7825.2830	Part A, Attachment 3 Part E, Attachment 3	NA
Part G, Schedule 4	Fossil Fuel Costs	Rule 7825.2830	Part B, Attachment 2	NA
Part G, Schedule 5	Coal Burn Expenses	Rule 7825.2830	Part B, Attachment 3	NA
Part G, Schedule 6	Nuclear Fuel Expenses	Rule 7825.2830	Part B, Attachment 4	NA
Part G, Schedule 7	Peak Demand and Energy Requirements	Rule 7825.2830	Part A, Attachment 4 Part E, Attachment 4	NA
Part G, Schedule 8	Estimated Load Management Impact	Rule 7825.2830	Part E, Attachment 5	NA

Former AAA	Description	Docket or Rule	April 30, 2021 Annual Forecast of Rates	March 1, 2023 Annual True-Up Filing
Part H, Section 3	Natural Gas Financial Instruments	Dockets M-01-1953 and AA-02-950	NA	Report Narrative Part E, Attachments 1 and 2
Part H, Section 5, Schedule 1	Wind Curtailment Summary	Dockets M-00-622, M-02-51, M-04-404, CN-01-1958, M-04-864, M-05-1850, M-05-1934 and M-06-85	NA	Part C, Attachment 2
Part H, Section 5, Schedule 2	Wind Curtailment Report Narrative	Docket AA-04-1279	Discussed in Petition Part G, Workpaper 10	Part C, Attachment 1
Part H, Section 6	KODA PPA	Docket M-08-1098	NA	Part F, Attachment 1
Part H, Section 7	WMRE PPA	Docket M-10-61	NA	Part F, Attachment 1
Part H, Section 8	Diamond K Dairy PPA	Docket M-486	NA	Part F, Attachment 1
Part H, Section 9 and Schedules H-9-1 and H-9-2	Community Solar Gardens	Docket M-13-867	Discussed in Petition Part B, Attachment 12 Part G, Workpapers 8 & 9	Part C, Attachments 8, 9, 10 Report Narrative
Part H, Section 10	FCA Rule Variance Dockets	Docket AA-15-611	Discussed in Petition Part C, Attachment 2	Part F, Attachment 4
Part H, Section 11	HERC	Docket M-17-532	NA	Part F, Attachment 1
Part J, Sections 1-3	Summary of key factors affecting costs in the forecast, and plan for acquiring fuel and purchased energy	Docket 04-1970, Docket 06-1208, Docket GR-05-1428	Discussed in Petition	NA
Part J, Section 5	Monthly MISO Day 2 charges and allocation	Docket AA-07-1130	Discussed in Petition Part B, Attachment 8 Part F, Workpaper 5	Part B
Part J, Section 6	Annual and Daily Ancillary Services Market charges and summary	Docket M-08-528	NA	Part B
Part K, Section 1	Generation facilities maintenance expenses	Docket AA-06-1208	NA	Part C, Attachment 6
Part K, Section 3	Contractor and supplier performance	Docket AA-08-995	NA	Part C, Attachment 3
Part K, Section 4 Schedule 1	Offsetting Revenues and/or compensation Received by IOUs	Docket AA-10-884	NA	Part F, Attachment 1
Part K, Section 4 Schedule 2	Handling of forced outages	Docket 08-995 and Docket AA-10-884	NA	Part C, Attachments 3, 4, 5
Part K, Section 4 Schedule 3	Unusual Adjustments over $500,000	Dockets AA-09-961 and AA-10-884	NA	Part F, Attachment 3
New Compliance	Self-Scheduling	Docket AA-17-492	NA	Provided in 3/1/23 Report in Docket No. E999/CI-19-704
Part M	Notice of Reports Availability	Rule 7825.2840	Addendum to Petition	Part F, Attachment 7
New Compliance	Renewable*Connect Neutrality	Docket M-15-985	Discussed in Petition Part G, Workpaper 14	Part F, Attachment 2

The Commission's July 21, 2017 Order in Docket No. E999/AA-15-611 requires electric utilities to identify all dockets in which the Commission has granted rule variances to a utility's FCA (such as those authorizing true-up provisions, those allowing costs of purchased power adjustments to flow through the FCA, and those allowing MISO costs and revenues to be included in the FCA). The variances and dockets pertaining to the 2022 FCA true-up and AAA reporting period are listed below.

- Wind, Biomass and Others – E002/M-95-244, E002/M-96-934, E,G002/M-97-985, E002/M-17-530, E002/M-17-531, E002/M-17-532, E002/M-17-551, and E002/M-17-694
- Fuel Clause Reform – E999/CI-03-802, Orders dated December 19, 2017, June 12, 2019, and November 5, 2019
- <u>2021 Fuel Forecast and Factors – E002/AA-20-417, Order dated July 5, 2022</u>
- 2022 Fuel Forecast and Factors– E002/AA-21-295, Order dated December 2, 2021 and <u>Rate Adjustment filing dated May 19, 2022</u>

For the 12 months ending December 31, 2022, computations of the monthly fuel clause adjustment factors also reflected the MISO Day 2 and ASM charges recovery, wind contracts curtailment payments, renewable energy purchase agreements, Windsource exemption and end-of-life nuclear fuel accrual. These additional components of the FCA were approved by the MPUC in the following dockets:

- MISO ASM – E002/M-08-528
- MISO Day 2 – E002/M-04-1970
- Wind Contracts Curtailment Payments – E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/M-04-864, E002/CN-01-1958, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934, and E002/M-06-85
- Renewable Energy Purchase Agreements:
    - KODA Energy, LLC, E002/M-08-1098, Order dated January 29, 2009
    - Woodstock, LLC, Amendment approved in E002/M-17-26, Order dated October 8, 2018.
    - Winona, LLC, E002/M-09-1247, Notice of Approval dated December 1, 2009
    - Adams, LLC, E002/M-09-1366, Notice of Approval dated December 29, 2009
    - Danielson, LLC, E002/M-09-1367, Notice of Approval dated December 29, 2009

  - Best Power, LLC, Amendment approved in E002/M-14-490, Order dated September 8, 2014
  - WM Renewable Energy, LLC, E002/M-10-161, Order dated April 30, 2010
  - Big Blue, LLC, Amendment approved in E002/M-13-1002, Order dated February 27, 2014.
  - Hilltop, E002/M-08-47, Notice of Approval dated February 15, 2008
  - Valley View, E002/M-08-1235, Order dated March 9, 2009
  - Ridgewind, E002/M-08-1428, Notice of Approval dated January 2, 2009
  - Moraine II, Amendment approved in E002/M-19-58, Order dated March 25, 2019
  - Ewington Energy Systems LLC, E002/M-06-1472, Notice of Approval dated November 30, 2006
  - Uilk Wind Farm, LLC, E002/M-08-1502, Notice of Approval dated February 6, 2009
  - Prairie Rose Wind, LLC, E002/M-11-713, Order dated December 28, 2011
  - Diamond K Dairy, E002/M-10-486, Order dated August 26, 2010
  - School Sisters, E002/M-15-619, Order dated September 14, 2015
  - Aurora Solar, E002/M-15-330, Order dated August 2, 2015
  - Marshall and NorthStar Solar, E002/M-14-162, Order dated March 24, 2015
  - Slayton Solar, E002/M-11-490, Order dated September 14, 2011
  - Dragonfly Solar, E002/M-17-561, Order dated October 12, 2017
  - University of Minnesota South East Plant, E002/M-20-39, Order dated April 10, 2020
  - Crowned Ridge and Clean Energy #1 – E002/M-16-777, Order dated September 1, 2017
  - Dakota Range III – E002/M-18-765, Order dated July 19, 2019
  - St. Paul Cogeneration – E002/M-21-590, Order dated January 24, 2022
- WindSource Exemption – E002/M-01-1479, E002/M-09-1177, Order dated June 21, 2010
- End-Of-Life Nuclear Fuel Accrual – E002/M-05-1648
- Community Solar Gardens Program – E002/M-13-867
- Renewable*Connect Government Program – E002/M-15-985
- Renewable*Connect – Docket No. E002/M-19-33
- Solar Energy Standard Exemption – E002/M-17-425, Order dated October 12, 2017
- Acquisition of Community Wind North and Jeffers Wind Facilities – E002/PA-18-777, Order dated December 3, 2019

FUEL PROCUREMENT POLICIES

A. Coal

Xcel Energy's coal procurement policy provides that coal and transportation services will be purchased at the lowest reasonable cost within the constraints of environmental regulations, supply reliability, operational compatibility, and consistency with Xcel Energy's inventory needs. The Company obtains its coal through a combination of long- and short-term contracts, including spot coal markets. A listing of current coal supply and transportation contracts and cost changes is shown on Part D, Attachments 3, 4 and 6.

Formal analysis of coal supply requirements for future years is performed on a regular basis. This multi-year analysis generally leads to solicitations for offers to supply unfulfilled requirements and/or bids to purchase coal. The solicitation process typically leads to purchases to fill the targeted percentages of near-term requirements based on a layered approach that varies from station to station. For example, purchases for the King Station are targeted at **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] When the transaction terms are attractive, Xcel Energy may fill different proportions of its future requirements. Xcel Energy continually reviews the current year's coal consumption to determine changes in coal requirements caused by such variables as weather, transportation availability, outage schedule revisions, capacity factors, and alternative electric sources. If there is an imbalance during an operational year between purchased coal supplies and station requirements, the additional fuel supply need is then corrected through such means as purchases based on spot coal market and transportation conditions at that time. Xcel Energy also monitors future years' needs on a continual basis.

The coal procurement strategy addresses the risk of supply interruption and exposure to market price fluctuations. Supply interruption can result from mine and/or transportation failures. Supply diversification is used to minimize the risk of mine failures and enhance market competition. Multiple suppliers are pre-qualified for each plant. Also, new contracts for coal supply generally do not include a specific destination, which allows coal to be moved to the generating facility where it is most needed. Supply interruptions resulting from transportation failures have been minimized through plant-specific inventory targets. When transportation performance degrades, the Company initiates close contact with our rail providers at all management levels to improve and restore service levels. Where necessary, other communication channels may be explored to exert all possible pressure to improve transportation service. **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

Fuel transportation service contracts are executed for various multiyear terms depending on market conditions, anticipated future market conditions, and plant delivery requirements. Proposed rates are vetted internally and externally through consultants and are compared to peers in the market to ensure price competitiveness. The final agreements for transportation of fuels may include minimum tonnage requirements.

B. Nuclear

The spot market price for uranium started 2023 at $47.75 per pound, which is an increase of $5.65 as compared to the beginning of 2022. During the early part of first quarter of 2023, the spot market price has ranged from $47.75 per pound to a high of $50.50 per pound in late January. This market volatility is mainly due to geopolitical pressures, transportation challenges, and the potential for disruption of supply from Russia.

Spot market volume declined in 2022. However, there has been an increase in activity of term contracting. The 2022 term contracting volume is the highest since 2012. Continued strength in reported long-term market prices which have risen to $51 per pound in December of 2022 from $40.50 per pound in December of 2021 and $32 per pound in July of 2021has resulted in several uranium mine operators announcing restarts of existing mines. While forecasted levels of uranium production have increased, continued growth in forecasted global demand has increased. The world's forecasted uncovered requirements of 1.6 million pounds in 2030 rises to 3.8 billion pounds by 2040 as new nuclear plants are completed and existing nuclear plants in Japan are expected to be restarted. Throughout 2022 and continuing into 2023, uranium security of supply issues remain of concern as the impact of supply chain and transportation challenges due to geopolitical pressures and Russia's on-going war in the Ukraine. Differences between supply and demand is projected to be covered by end user inventories in 2023. Spot market volume at 57.4 million pounds of U3O8 for 2022 is significantly below the 102.4 million pounds of U3O8 reported for 2021. Spot market volumes in 2023 are predicted to range from 53 - 98 million pounds of U3O8. Spot market prices for 2023 through 2025 are project to average about 6% higher than 2022. The current market analysis forecasts global supply and inventories meeting demand until about 2024 with small supply deficits projected in 2024 and 2025 (2 million and 4 million pounds, respectively). The current market analysis forecasts a global supply deficit relative to projected demand of between 4 to 8 million pounds in the years 2026 through 2028, but will continue to be dependent on the willingness of suppliers to bring new supply into the market.

The potential western sanctions against Russia continue to provide uncertainty with regard to price impacts or supply interruptions. Numerous U.S. utilities have contracted for supply of enriched uranium from Russia beyond 2022. If sanctions impact the supply of enriched uranium from Russia to customers in the U.S. or EU, either directly (or indirectly through sanctions on the banking infrastructure), the price of uranium could continue be significantly impacted. A list of current nuclear fuel components of service contracts is shown on Part D, Attachment 2.

C. Natural Gas

In contracting for natural gas, a combination of baseload purchases, daily spot purchases, and storage are utilized to meet the portfolio requirements. The basic premise is that base load purchases are used to meet the minimum daily portfolio requirements, and the incremental burns above the minimum requirements are met using a combination of daily spot purchases and storage.

D. Woody Biomass

Xcel Energy establishes woody biomass supply contracts with a diverse group of suppliers. Sources of woody biomass include waste products from lumber mills and wood products industries, chipped bark and limbs from municipal tree trimming operations, chipped slash from logging operations, chipped pallets and demolition debris diverted from landfills, as well as shredded creosote-treated railroad ties. All wood fuel is chipped to sizing specifications and delivered by truck to the plants. There are currently between 25 and 30 suppliers that provide wood fuel to two plants. Our practice has been to establish long-term relationships with a select group of local suppliers. The criteria for selection of suppliers are: 1) dependable supply, 2) consistent quality, and 3) reasonable pricing. By ensuring that these suppliers sustain viable small businesses, we in turn can be reasonably confident that we will receive consistent supplies of wood fuel to our plants. Contracts are typically executed with terms from 1 to 5 years. See Part D, Attachment 5 for a listing of the contracts, and Part D, Attachment 6 for a listing of cost changes. We have been able to maintain biomass pricing for our power plants below pulpwood industry prices to avoid potential competition for woody biomass with the pulp and paper industry.

E. Refuse-Derived Fuel (RDF)

Xcel Energy has established five contracts for the supply of refuse-derived fuel (RDF) for three power plants (Red Wing and Wilmarth, Minnesota, and French Island, Wisconsin). See Part D, Attachment 5 for a listing of the contracts, and Part D, Attachment 6 for a listing of cost changes. Four of the contracts provide for the delivery of processed RDF to two of the plants. Xcel Energy also has a service agreement with La Crosse County, Wisconsin, which provides for the processing of municipal solid waste (MSW) into RDF and combustion of the RDF at the French Island facility in LaCrosse. Almost all of the county's MSW is processed and disposed at the Xcel Energy facility, with the exception of materials recovered for recycling, and non-combustible or non-recoverable materials and ash byproducts which are disposed in the County's landfill.

[PROTECTED DATA BEGINS

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Nuclear Fuel Components of Services for the Period of January through December 2022

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
	[PROTECTED DATA BEGINS			
1				
2				
3				
4				
5				
6				
				PROTECTED DATA ENDS]

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
7				
8				
9				
10				
11				
12				
13				
14				
				PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEN EXCISED

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
15				
16				
17				
18				
19				
				PROTECTED DATA ENDS]

Coal Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity or Volume (million tons/year)	Contract Expiration Date
[PROTECTED DATA BEGINS				
1				
2				
3				
4				
5				
6				
7				
8				
				PROTECTED DATA ENDS]

Transportation & Related Services Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
1				
2				
3				
4				
				PROTECTED DATA ENDS]

Wood and RDF Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
1				
2				
3				
4				
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7				
8				
9				
10				
11				
				PROTECTED DATA ENDS]

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
12				
13				
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23				
				PROTECTED DATA ENDS]

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
24				
25				
26				
27				
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29				
				PROTECTED DATA ENDS]

Cost Changes – January 1, 2022 to January 1, 2023

	Contract	Percent Change
[PROTECTED DATA BEGINS		

PROTECTED DATA ENDS]

Cost Changes – January 1, 2022 to January 1, 2023

	Contract*	Percent Change
[PROTECTED DATA BEGINS		
		PROTECTED DATA ENDS]

	Contract*	Percent Change
[PROTECTED DATA BEGINS		
		PROTECTED DATA ENDS]

*The majority of wood contracts are renewed with similar terms on an annual basis. The cost change represented is the related contract price on January 1, 2022 compared to the contract price on January 1, 2023.

DISPATCHING POLICIES AND PROCEDURES

The goal for Xcel Energy's dispatching policies and procedures is to provide our native load customers with low-priced reliable electric energy services. This goal is achieved primarily by closely monitoring our load and managing our generation system and purchased energy resources to provide the most economic loading of our own generation units in conjunction with leveraging the competitive wholesale energy and fuel markets. We discuss the Company's policies about self-commitment and self-scheduling of plants in our March 1 annual report filed in Docket No. E999/CI-19-704.

Xcel Energy devotes significant resources to managing our participation in MISO's wholesale energy market, which began operation on April 1, 2005 and increased functions on January 6, 2009. The MISO market altered the method by which we optimize our resources on behalf of our ratepayers, since all resources and load must be scheduled and cleared through MISO's Day Ahead and Real Time markets. However, this change has not altered our overarching goal of reliably providing our customers with the lowest possible energy cost. The Company continues to purchase energy in the the MISO Day Ahead and Real Time markets whenever the market price of purchased energy is below our avoided cost of production. Additionally, we continue to work with MISO to coordinate our efforts to obtain maximum value of our generation and purchased resources for customers.

The Company uses MISO Ancillary Services Market to co-optimize energy and ancillary services markets, resulting in a net benefit to ratepayers.

Another component of the Company's dispatching policy is forecasting how much wind will be on the system at a given time. The Company developed a wind generation forecasting tool in partnership with the National Center for Atmospheric Research. Xcel Energy uses this tool to forecast output from all NSP system wind farms, resulting in a reduction of wind forecast error. Similarly, Xcel Energy uses a solar forecast developed in conjunction with Global Weather Corporation (GWC) to estimate production from NSP system solar facilities. Reductions in forecast error translate directly into a long term decrease in fuel and purchased power costs because improved forecast for renewable energy reduces the need for excessive commitment of thermal resources.

In summary, Xcel Energy's dispatching policies and procedures, while focused on reliable service, are influenced by a goal of lowest cost in an uncertain environment.

Based on the best available information and analytical tools, Xcel Energy attempts to optimally offer our generation units to both minimize energy costs and mitigate the risks of higher than expected costs. These efforts include dispatching practices aimed at controlling wind curtailment costs. Given the potential uncertainties regarding load, generation plant availability, transmission limitations, and wholesale market prices, this requires continual analysis and rapid response to changing conditions, both on an expected (day ahead) and real-time basis.

FUEL SUPPLY

a. Nuclear Fuel

1. Nuclear fuel costs are economically competitive. The average total fuel cost at Prairie Island and Monticello was approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** mills/kWh in 2022.

2. **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** have been managed to ensure security of supply and take advantage of market opportunities.

3. Two contracts were executed in **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**

b. Fossil Fuel

1. Public documents released by the U.S. Energy Information Agency report average coal costs for utility consumption delivered in the U.S. was $1.98/MBtu during 2021. (https://www.eia.gov/electricity/annual/html/epa_07_01.html) During this same period, Northern States Power Company – Minnesota's average delivered coal cost was **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. NSP's average delivered coal cost for 2020 was **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

2. NSP has re-emphasized its program to review or modify, as appropriate, coal procurement strategy **[PROTECTED DATA BEGINS**

   PROTECTED DATA ENDS]

3. NSP maintained contract supplies, satisfied generation coal requirements, and produced fuel expense reductions.

4. Xcel Energy Services, Inc. negotiates terms with existing major coal suppliers on behalf of NSP **[PROTECTED DATA BEGINS**

   PROTECTED DATA ENDS]

c. MISO Energy Charges

The Company actively checks, investigates, and disputes (when appropriate) calculations and the charges billed by MISO in the Day 2 energy market. From January through December 2022, the Company submitted two disputes for operating days in 2022, although the second one was rejected as a duplicate.

NSP MISO Dispute Status

Disputed $ Amount			Dispute Status			
YEAR	Op Month	Operating Date	GRANTED	DENIED	OPEN	TOTAL
2022	2022-12	12/15/22	$0.00	$1,916,558.13	$0.00	$1,916,558.13
TOTAL			$0.00	$1,916,558,13	$0.00	$1,916,558.13

The total dollar amount disputed in the 2022 AAA period was $1,916,558.13, which is higher than the 2021 AAA period of $0. The dispute was denied and was closed. All other discrepancies not requiring a formal dispute are identified during our daily checkout process and generally resolved through the normal settlement process.

ENERGY CONSERVATION AND OPTMIZATION PROGRAM

Xcel Energy's Energy Conservation and Optimization Program (ECO) is designed to help our customers use energy wisely. The Company has developed nearly 40 commercial and residential convservation improvement programs with the intent of providing customers the opportunity to lower their energy consumption and overall energy bills. As part of this portfolio, the Company has several electric load management programs available to customers including rate discounts for reducing electric loads on days with peak demand for electricity or rebates for participation in control events utilizing a smart thermostat.

Minn. Stat. § 216B.2401 and 216B.241 require certain Minnesota utilities, including Xcel Energy's electric utility, to invest in cost-effective conservation improvements through ECO. ECO programs are subject to regulation by the Minnesota Department of Commerce (Department). Currently, the Company offers a wide variety of programs that assist customers in implementing energy efficiency measures, ranging from rebates for high efficiency equipment to home energy squad visits. By conserving energy (i.e. using less of it) and varying loads (i.e. interrupting a constant demand to lessen the peak kilowatt impact), customers will experience an overall reduction in their utility bills. Both methods mitigate the Company's power producing and purchasing needs. Moreover, both are considered in the Company's integrated resource planning process.

The Company is required to file with the Department every three years, an Energy Conservation and Optimization Triennial Plan detailing our goals, budgets and cost-effectiveness analyses for the next planning cycle. A detailed description and analysis of the Company's electric conservation policy and programs may be found in the Company's current 2021-2023 Conservation Improvement Plan (CIP) Triennial Plan,[1] which was filed on July 1, 2020 and approved on November 25, 2020.[2]

On April 1 of each year, the Company is required to file with the Department an annual Status Report, which details the cost-effectiveness and spending for the prior year's program. The Deputy Commissioner issued approval of the Company's 2021 CIP Status Report on July 7, 2022.[3]

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[1] Minn.Stat. §216B.241 was adjusted in 2021 to enact changes to the Conservation Improvement Plan to modernize its scope to include additional load management technologies and beneficial electrification. This change is under the Energy Conservation and Optimization Act or ECO.
[2] Docket No. E,G002/CIP-20-473
[3] Docket No. E,G002/CIP-20-473

OTHER ACTIONS TO MINIMIZE COSTS

The Company continues to actively represent the interests of its Minnesota electric customers before national regulatory agencies to minimize the cost of wholesale electric supplies and third party transmission services to be recovered from Minnesota retail electric customers. The Company does this as an individual intervenor, through intervenor groups such as the MISO Transmission Owners (TOs), and through its membership in the Edison Electric Institute (EEI), which actively represents its members in major policy proceedings such as Federal Energy Regulatory Commission (FERC) rulemakings.

1. PARTICIPATION IN THE MISO TRANSMISSION OWNERS COMMITTEE

Northern States Power Company Minnesota (NSPM) and Northern States Power Company Wisconsin (NSPW) are transmission-owning members of MISO. NSPM and NSPW (jointly, the NSP Companies)[1] participate in the MISO Transmission Owning Committee (TOC). Not all MISO transmission-owning companies participate in the TOC.

The MISO TOC members jointly intervene in numerous FERC and other proceedings. The MISO TOC members own a substantial portion of the transmission facilities subject to MISO functional control, representing approximately two-thirds of all load in the MISO footprint. Other Minnesota entities that are MISO TOC members include Great River Energy, Minnesota Power, Otter Tail Power Company, Southern Minnesota Municipal Power Agency, ITC Midwest, LLC, Minnesota Municipal Power Agency, and Central Minnesota Municipal Power Agency. NSPM is also a participant on the Transmission Owners Tariff Working Group, which makes recommendations to the TOC on certain rate and revenue distribution changes pursuant to the MISO Transmission Owners Agreement (TOA). Xcel Energy representatives also participate in all other MISO committees, such as the Market Sub-Committee, Planning Advisory Committee, Reliability Sub-Committee and Regional Criteria and Benefits Working Group. These committees are critical to ensuring the development of transmission system additions that achieve maximum efficiency benefits.

[1] The Company and NSPW are jointly referred to as the "NSP Companies," and their integrated electric generation and transmission system is referred to as the "NSP System."

2. SIGNIFICANT MISO DEVELOPMENTS/ACTIONS

The Company has been active in a number of proceedings before the FERC. To the extent the Department or the Commission or another stakeholder desires information related to specific proceedings, the Company will provide the additional information upon request.

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2028

Line #	*Costs in $1,000's*	1/1/25	2/1/25	3/1/25	4/1/25	5/1/25	6/1/25	7/1/25	8/1/25	9/1/25	10/1/25	11/1/25	12/1/25	2025 Total
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$15,998	$22,688	$31,833	$36,526	$42,482	$37,297	$43,987	$41,930	$29,421	$23,110	$15,634	$12,523	$353,431
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	MISO Market Charges													
25	Subtotal													
26														
27	**Total System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**	($9,370)	($13,591)	($25,349)	($28,512)	($33,210)	($27,519)	($29,338)	($27,984)	($21,101)	($16,910)	($11,369)	($9,270)	($253,522)
31	**Less Renewable*Connect Pilot**													
32	**Less Renewable*Connect MTM**													
33	**Less Renewable*Connect LT**													
34														
35	**NSP Net System Costs Excluded CSG Above Mark**													
36	**& Renewable*Connect Costs**													
37														
38	**Interchange Agreement Energy Req Allocator**													
39														
40	**NSPM System Costs Excluded CSG Above Market**													
41	**& Renewable*Connect Costs**													
42														
43	**NSPM System Calendar Month MWh Sales**													
44														
45	**Less Renewable*Connect Pilot MWh Sales**													
46	**Less Renewable*Connect MTM MWh Sales**													
47	**Less Renewable*Connect LT MWh Sales**													
48														
49	**Net NSPM System Calendar Month MWh Sales**													
50														
51	**NSPM System Cost in cents/kWh**													
52														
53	**Minnesota Jurisdiction MWh Sales**													
54														
55	**Less Renewable*Connect Pilot MWh Sales**													
56	**Less Renewable*Connect MTM MWh Sales**													
57	**Less Renewable*Connect LT MWh Sales**													
58														
59	**Net MN MWh Sales**													
60														
61	**MN Fuel Cost**													
62	**Solar Gardens - Above Market Cost**	$9,370	$13,591	$25,349	$28,512	$33,210	$27,519	$29,338	$27,984	$21,101	$16,910	$11,369	$9,270	$253,522
63	**Laurentian Buyout Costs**													
64	**Pine Bend Buyout Cost**													
65	**Benson Buyout Cost**													
66														
67	**Forecast MN FCA Costs**													
68														
69														
70	**Forecast MN FCA Cost in cents/kWh**													
71														
72														
73	**Forecast MN FCA Cost in $/MWh**													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2028

Line #	*Costs in $1,000's*	1/1/26	2/1/26	3/1/26	4/1/26	5/1/26	6/1/26	7/1/26	8/1/26	9/1/26	10/1/26	11/1/26	12/1/26	2026 Total
2														
3	**Own Generation**													
4	Fossil Fuel	[PROTECTED DATA BEGINS												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$17,265	$24,382	$34,077	$38,958	$45,155	$39,516	$46,461	$44,160	$30,901	$24,208	$16,336	$13,054	$374,472
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	MISO Market Charges													
25	Subtotal													
26														
27	**Total System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**	($11,928)	($17,240)	($26,247)	($29,687)	($34,302)	($27,889)	($28,801)	($27,717)	($21,446)	($17,632)	($12,006)	($9,690)	($264,585)
31	**Less Renewable*Connect Pilot**													
32	**Less Renewable*Connect MTM**													
33	**Less Renewable*Connect LT**													
34														
35	**NSP Net System Costs Excluded CSG Above Mark**													
36	**& Renewable*Connect Costs**													PROTECTED DATA ENDS]
37														
38	**Interchange Agreement Energy Req Allocator**													
39														
40	**NSPM System Costs Excluded CSG Above Market**													
41	**& Renewable*Connect Costs**													
42														
43	**NSPM System Calendar Month MWh Sales**													
44														
45	**Less Renewable*Connect Pilot MWh Sales**													
46	**Less Renewable*Connect MTM MWh Sales**													
47	**Less Renewable*Connect LT MWh Sales**													
48														
49	**Net NSPM System Calendar Month MWh Sales**													
50														
51	**NSPM System Cost in cents/kWh**													
52														
53	**Minnesota Jurisdiction MWh Sales**													
54														
55	**Less Renewable*Connect Pilot MWh Sales**													
56	**Less Renewable*Connect MTM MWh Sales**													
57	**Less Renewable*Connect LT MWh Sales**													
58														
59	**Net MN MWh Sales**													
60														
61	**MN Fuel Cost**													
62	**Solar Gardens - Above Market Cost**													
63	**Laurentian Buyout Costs**													
64	**Pine Bend Buyout Cost**													
65	**Benson Buyout Cost**													
66														
67	**Forecast MN FCA Costs**													
68														
69														
70	**Forecast MN FCA Cost in cents/kWh**													
71														
72														
73	**Forecast MN FCA Cost in $/MWh**													

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2028

Line #														
1	*Costs in $1,000's*	1/1/27	2/1/27	3/1/27	4/1/27	5/1/27	6/1/27	7/1/27	8/1/27	9/1/27	10/1/27	11/1/27	12/1/27	2027 Total
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$19,739	$27,819	$38,805	$44,285	$51,248	$44,783	$52,583	$49,918	$34,891	$27,306	$18,410	$14,699	$424,485
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	MISO Market Charges													
25	Subtotal													
26														
27	**Total System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**	($14,480)	($21,038)	($30,582)	($34,812)	($39,850)	($32,633)	($33,739)	($32,960)	($25,157)	($21,120)	($14,068)	($11,119)	($311,557)
31	**Less Renewable*Connect Pilot**													
32	**Less Renewable*Connect MTM**													
33	**Less Renewable*Connect LT**													
34														
35	**NSP Net System Costs Excluded CSG Above Mark**													
36	**& Renewable*Connect Costs**													**PROTECTED DATA ENDS]**
37														
38	**Interchange Agreement Energy Req Allocator**													
39														
40	**NSPM System Costs Excluded CSG Above Market**													
41	**& Renewable*Connect Costs**													
42														
43	**NSPM System Calendar Month MWh Sales**													
44														
45	**Less Renewable*Connect Pilot MWh Sales**													
46	**Less Renewable*Connect MTM MWh Sales**													
47	**Less Renewable*Connect LT MWh Sales**													
48														
49	**Net NSPM System Calendar Month MWh Sales**													
50														
51	**NSPM System Cost in cents/kWh**													
52														
53	**Minnesota Jurisdiction MWh Sales**													
54														
55	**Less Renewable*Connect Pilot MWh Sales**													
56	**Less Renewable*Connect MTM MWh Sales**													
57	**Less Renewable*Connect LT MWh Sales**													
58														
59	**Net MN MWh Sales**													
60														
61	**MN Fuel Cost**													
62	**Solar Gardens - Above Market Cost**													
63	**Laurentian Buyout Costs**													
64	**Pine Bend Buyout Cost**													
65	**Benson Buyout Cost**													
66														
67	**Forecast MN FCA Costs**													
68														
69														
70	**Forecast MN FCA Cost in cents/kWh**													
71														
72														
73	**Forecast MN FCA Cost in $/MWh**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2028

Line #		1/1/28	2/1/28	3/1/28	4/1/28	5/1/28	6/1/28	7/1/28	8/1/28	9/1/28	10/1/28	11/1/28	12/1/28	2028 Total
1	*Costs in $1,000's*													
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$20,435	$30,068	$40,119	$45,757	$52,922	$46,222	$54,248	$51,477	$35,967	$28,138	$18,964	$15,137	$439,455
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	MISO Market Charges													
25	Subtotal													
26														
27	**Total System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**	($14,929)	($23,145)	($31,709)	($36,625)	($41,782)	($35,354)	($37,395)	($36,470)	($26,771)	($21,842)	($14,564)	($11,593)	($332,180)
31	**Less Renewable*Connect Pilot**													
32	**Less Renewable*Connect MTM**													
33	**Less Renewable*Connect LT**													
34														
35	**NSP Net System Costs Excluded CSG Above Mark**													
36	**& Renewable*Connect Costs**													**PROTECTED DATA ENDS]**
37														
38	**Interchange Agreement Energy Req Allocator**													
39														
40	**NSPM System Costs Excluded CSG Above Market**													
41	**& Renewable*Connect Costs**													
42														
43	**NSPM System Calendar Month MWh Sales**													
44														
45	**Less Renewable*Connect Pilot MWh Sales**													
46	**Less Renewable*Connect MTM MWh Sales**													
47	**Less Renewable*Connect LT MWh Sales**													
48														
49	**Net NSPM System Calendar Month MWh Sales**													
50														
51	**NSPM System Cost in cents/kWh**													
52														
53	**Minnesota Jurisdiction MWh Sales**													
54														
55	**Less Renewable*Connect Pilot MWh Sales**													
56	**Less Renewable*Connect MTM MWh Sales**													
57	**Less Renewable*Connect LT MWh Sales**													
58														
59	**Net MN MWh Sales**													
60														
61	**MN Fuel Cost**													
62	**Solar Gardens - Above Market Cost**													
63	**Laurentian Buyout Costs**													
64	**Pine Bend Buyout Cost**													
65	**Benson Buyout Cost**													
66														
67	**Forecast MN FCA Costs**													
68														
69														
70	**Forecast MN FCA Cost in cents/kWh**													
71														
72														
73	**Forecast MN FCA Cost in $/MWh**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2028

Line #														
1	*Energy in GWhs*	**1/1/25**	**2/1/25**	**3/1/25**	**4/1/25**	**5/1/25**	**6/1/25**	**7/1/25**	**8/1/25**	**9/1/25**	**10/1/25**	**11/1/25**	**12/1/25**	**2025 Total**
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	113.8	161.3	226.4	259.7	302.1	265.2	312.8	298.2	209.2	164.3	111.2	89.1	2,513.4
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System GWh**													
27														
28	**Less Sales GWh**													
29	**Less Renewable*Connect Pilot GWh**													
30	**Less Renewable*Connect MTM GWh**													
31	**Less Renewable*Connect LT GWh**													
32														
33	**Net System GWh**													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2028

Line #														
1	*Energy in GWhs*	**1/1/26**	**2/1/26**	**3/1/26**	**4/1/26**	**5/1/26**	**6/1/26**	**7/1/26**	**8/1/26**	**9/1/26**	**10/1/26**	**11/1/26**	**12/1/26**	**2026 Total**
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	121.3	171.3	239.5	273.8	317.3	277.7	326.5	310.3	217.1	170.1	114.8	91.7	2,631.4
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System GWh**													
27														
28	**Less Sales GWh**													
29	**Less Renewable*Connect Pilot GWh**													
30	**Less Renewable*Connect MTM GW**													
31	**Less Renewable*Connect LT GWh**													
32														
33	**Net System GWh**													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2028

Line #														
1	*Energy in GWhs*	**1/1/27**	**2/1/27**	**3/1/27**	**4/1/27**	**5/1/27**	**6/1/27**	**7/1/27**	**8/1/27**	**9/1/27**	**10/1/27**	**11/1/27**	**12/1/27**	**2027 Total**
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	124.7	175.7	245.1	279.7	323.7	282.8	332.1	315.3	220.4	172.5	116.3	92.8	2,681.0
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System GWh**													
27														
28	**Less Sales GWh**													
29	**Less Renewable*Connect Pilot GWh**													
30	**Less Renewable*Connect MTM GW**													
31	**Less Renewable*Connect LT GWh**													
32														
33	**Net System GWh**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2028

Line #		1/1/28	2/1/28	3/1/28	4/1/28	5/1/28	6/1/28	7/1/28	8/1/28	9/1/28	10/1/28	11/1/28	12/1/28	2028 Total
1	*Energy in GWhs*													
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	126.1	185.5	247.5	282.3	326.5	285.2	334.7	317.6	221.9	173.6	117.0	93.4	2,711.2
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System GWh**													
27														
28	**Less Sales GWh**													
29	**Less Renewable*Connect Pilot GWh**													
30	**Less Renewable*Connect MTM GW**													
31	**Less Renewable*Connect LT GWh**													
32														
33	**Net System GWh**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2028

Line #														
1	*$/MWh*	**1/1/2025**	**2/1/2025**	**3/1/2025**	**4/1/2025**	**5/1/2025**	**6/1/2025**	**7/1/2025**	**8/1/2025**	**9/1/2025**	**10/1/2025**	**11/1/2025**	**12/1/2025**	**2025 Total**
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$140.62	$140.62	$140.62	$140.62	$140.62	$140.62	$140.62	$140.62	$140.62	$140.62	$140.62	$140.62	$140.62
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System $/MWh**													
27														
28	**Less Sales**													
29	**Less Solar Gardens - Above Market Cost**	$82.36	$84.24	$111.98	$109.77	$109.93	$103.75	$93.79	$93.85	$100.85	$102.90	$102.26	$104.09	$100.87
30	**Renewable*onnect Pilot**													
31	**Renewable*Connect MTM**													
32	**Renewable*Connect LT**													
33														
34	**Net System $/MWh**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2028

Line #														
1	*$/MWh*	1/1/2026	2/1/2026	3/1/2026	4/1/2026	5/1/2026	6/1/2026	7/1/2026	8/1/2026	9/1/2026	10/1/2026	11/1/2026	12/1/2026	2026 Total
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$142.31	$142.31	$142.31	$142.31	$142.31	$142.31	$142.31	$142.31	$142.31	$142.31	$142.31	$142.31	$142.31
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System $/MWh**													
27														
28	**Less Sales**													
29	**Less Solar Gardens - Above Market Cost**	$98.32	$100.62	$109.61	$108.44	$108.11	$100.44	$88.22	$89.32	$98.77	$103.65	$104.59	$105.64	$100.55
30	**Renewable*onnect Pilot**													
31	**Renewable*Connect MTM**													
32	**Renewable*Connect LT**													
33														
34	**Net System $/MWh**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2028

Line #		1/1/2027	2/1/2027	3/1/2027	4/1/2027	5/1/2027	6/1/2027	7/1/2027	8/1/2027	9/1/2027	10/1/2027	11/1/2027	12/1/2027	2027 Total
1	*$/MWh*													
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$158.33	$158.33	$158.33	$158.33	$158.33	$158.33	$158.33	$158.33	$158.33	$158.33	$158.33	$158.33	$158.33
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System $/MWh**													
27														
28	**Less Sales**													
29	**Less Solar Gardens - Above Market Cost**	$116.14	$119.74	$124.78	$124.46	$123.12	$115.38	$101.59	$104.54	$114.16	$122.46	$120.99	$119.77	$116.21
30	**Renewable*onnect Pilot**													
31	**Renewable*Connect MTM**													
32	**Renewable*Connect LT**													
33														
34	**Net System $/MWh**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2028

Line #	*$/MWh*	1/1/2028	2/1/2028	3/1/2028	4/1/2028	5/1/2028	6/1/2028	7/1/2028	8/1/2028	9/1/2028	10/1/2028	11/1/2028	12/1/2028	2028 Total
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$162.09	$162.09	$162.09	$162.09	$162.09	$162.09	$162.09	$162.09	$162.09	$162.09	$162.09	$162.09	$162.09
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System $/MWh**													
27														
28	**Less Sales**													
29	**Less Solar Gardens - Above Market Cost**	$118.41	$124.77	$128.11	$129.74	$127.97	$123.98	$111.73	$114.84	$120.65	$125.82	$124.48	$124.13	$122.52
30	**Renewable*onnect Pilot**													
31	**Renewable*Connect MTM**													
32	**Renewable*Connect LT**													
33														
34	**Net System $/MWh**													

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Northern States Power Company
Electric Operations - State of Minnesota

Docket No. E002/AA-23-153
Petition
Part E, Attachment 4

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2025

[PROTECTED DATA BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2025 Total AVG
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Bay Front 5	Wood Coal Gas													
Bay Front 6	Wood Coal Gas													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake 9 Recip	Gas													
Blue Lake 9 Recip	Oil													
Blue Lake	AVG COST													
CC LSPower	Gas													
CC MEC I	Gas													
CC MEC II	Gas													
MEC	AVG COST													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island	AVG COST													
High Bridge 1x1	Gas													
High Bridge 2x1	Gas													
High Bridge	AVG COST													
Inver Hills 1	Gas													
Inver Hills 1	Oil													
Inver Hills 3	Gas													
Inver Hills 3	Oil													
Inver Hills 4	Gas													
Inver Hills 4	Oil													
Inver Hills 6	Gas													
Inver Hills 6	Oil													
Inver Hills	AVG COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	AVG COST													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal MT Sherburne County													
Sherburne 1	Coal WY Sherburne County													
Sherburne 1	Oil													
Sherburne 3	Coal MT Sherburne County													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Wheaton 1	Gas													
Wheaton 1	Oil													
Wheaton 2	Gas													
Wheaton 2	Oil													
Wheaton 3	Gas													
Wheaton 3	Oil													
Wheaton 4	Gas													
Wheaton 4	Oil													
Wheaton 6	Oil													
Wheaton 7	Gas													
Wheaton 8 Recip	Gas													
Wheaton 8 Recip	Oil													
Wheaton	AVG COST													
Willmarth 1	Gas													
Willmarth 1	RDF													
Willmarth 2	Gas													
Willmarth 2	RDF													
Wilmarth	AVG COST													
System MN	AVG COST													

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Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2026

[PROTECTED DATA BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2026 Total AVG
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Bay Front 5	Wood Coal Gas													
Bay Front 6	Wood Coal Gas													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake 9 Recip	Gas													
Blue Lake 9 Recip	Oil													
Blue Lake	AVG COST													
CC LSPower	Gas													
CC MEC I	Gas													
CC MEC II	Gas													
MEC	AVG COST													
Fargo	Gas													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island	AVG COST													
High Bridge 1x1	Gas													
High Bridge 2x1	Gas													
High Bridge	AVG COST													
Inver Hills 1	Gas													
Inver Hills 1	Oil													
Inver Hills 2	Gas													
Inver Hills 2	Oil													
Inver Hills 3	Gas													
Inver Hills 3	Oil													
Inver Hills 4	Gas													
Inver Hills 4	Oil													
Inver Hills 5	Gas													
Inver Hills 5	Oil													
Inver Hills 6	Gas													
Inver Hills 6	Oil													
Inver Hills	AVG COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	AVG COST													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal MT Sherburne County													
Sherburne 1	Coal WY Sherburne County													
Sherburne 1	Oil													
Sherburne 3	Coal MT Sherburne County													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Wheaton 7	Gas													
Wheaton 8 Recip	Gas													
Wheaton 8 Recip	Oil													
Wheaton	AVG COST													
Willmarth 1	Gas													
Willmarth 1	RDF													
Willmarth 2	Gas													
Willmarth 2	RDF													
Wilmarth	AVG COST													
System MN	AVG COST													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Operations - State of Minnesota

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2027

[PROTECTED DATA BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2027 Total AVG
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Bay Front 5	Wood Coal Gas													
Bay Front 6	Wood Coal Gas													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake 9 Recip	Gas													
Blue Lake 9 Recip	Oil													
Blue Lake	AVG COST													
CC LSPower	Gas													
CC MEC I	Gas													
Fargo	Gas													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island	AVG COST													
High Bridge 1x1	Gas													
High Bridge 2x1	Gas													
High Bridge	AVG COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	AVG COST													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 3	Coal MT Sherburne County													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Wheaton 7	Gas													
Wheaton 8 Recip	Gas													
Wheaton 8 Recip	Oil													
Wheaton	AVG COST													
Willmarth 1	Gas													
Willmarth 1	RDF													
Willmarth 2	Gas													
Willmarth 2	RDF													
Wilmarth	AVG COST													
System MN	AVG COST													

PROTECTED DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2028

[PROTECTED DATA BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2028 Total AVG
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Bay Front 5	Wood Coal Gas													
Bay Front 6	Wood Coal Gas													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake 9 Recip	Gas													
Blue Lake 9 Recip	Oil													
Blue Lake	AVG COST													
CC MEC I	Gas													
Fargo	Gas													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
High Bridge 1x1	Gas													
High Bridge 2x1	Gas													
High Bridge	AVG COST													
Lyon County	Gas													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 3	Coal MT Sherburne County													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Wheaton 7	Gas													
Wheaton 8 Recip	Gas													
Wheaton 8 Recip	Oil													
Wheaton	AVG COST													
System MN	AVG COST													

PROTECTED DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2025

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2025 Total AVG
		[PROTECTED DATA BEGINS												
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Sherburne 1	Coal MT Sherburne County													
Sherburne 1	Coal WY Sherburne County													
Sherburne 1	Oil													
Sherburne 3	Coal MT Sherburne County													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Coal	AVG COST													

PROTECTED DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2026

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2026 Total AVG
		[PROTECTED DATA BEGINS												
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Sherburne 1	Coal MT Sherburne County													
Sherburne 1	Coal WY Sherburne County													
Sherburne 1	Oil													
Sherburne 3	Coal MT Sherburne County													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Coal	AVG COST													
														PROTECTED DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2027

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2027 Total AVG
		[PROTECTED DATA BEGINS												
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Sherburne 3	Coal MT Sherburne County													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Coal	AVG COST													
														PROTECTED DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2028

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2028 Total AVG
		[PROTECTED DATA BEGINS												
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Sherburne 3	Coal MT Sherburne County													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Coal	AVG COST													
														PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Operations - State of Minnesota
Nuclear Fuel Expense (Units noted in row)

Docket No. E002/AA-23-153
Petition
Part E, Attachment 6

[PROTECTED DATA BEGINS

Item ID	Item Description (Q1-2023 02-13-23 10:50:02)	Jan 2025	Feb 2025	Mar 2025	Apr 2025	May 2025	Jun 2025	Jul 2025	Aug 2025	Sep 2025	Oct 2025	Nov 2025	Dec 2025
1	Prairie Island 1 - Heat Generation (1000 MBTU)												
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)												
3	Prairie Island 1 - Maximum Capacity (MWe-Net)												
4	Prairie Island 1 - Current Capability (MWe-Net)												
5	Prairie Island 1 - Thermal Capability (MWth)												
6	Prairie Island 1 - Monthly Capacity Factor (%)												
7	Prairie Island 1 - Monthly Minor Outage Rate (%)												
8	Prairie Island 1 - Days Offline in Month for Refuelin												
9	Prairie Island 1 - Refueling Outage Start Date												
10	Prairie Island 1 - Refueling Outage Start Time (HH.MM												
11	Prairie Island 1 - Refueling Outage End Date												
12	Prairie Island 1 - Refueling Outage End Time (HH.MM)												
13	Prairie Island 1 - Fuel Expense - Dollars												
14	Prairie Island 1 - Fuel Expense - Cents/MBTU												
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe												
16	Prairie Island 2 - Heat Generation (1000 MBTU)												
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
18	Prairie Island 2 - Maximum Capacity (MWe-Net)												
19	Prairie Island 2 - Current Capability (MWe-Net)												
20	Prairie Island 2 - Thermal Capability (MWth)												
21	Prairie Island 2 - Monthly Capacity Factor (%)												
22	Prairie Island 2 - Monthly Minor Outage Rate (%)												
23	Prairie Island 2 - Days Offline in Month for Refuelin												
24	Prairie Island 2 - Refueling Outage Start Date												
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM												
26	Prairie Island 2 - Refueling Outage End Date												
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)												
28	Prairie Island 2 - Fuel Expense - Dollars												
29	Prairie Island 2 - Fuel Expense - Cents/MBTU												
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
32	Monticello - Net Electric Generation (MWHe-Net)												
33	Monticello - Maximum Capacity (MWe-Net)												
34	Monticello - Current Capability (MWe-Net)												
35	Monticello - Thermal Capability (MWth)												
36	Monticello - Monthly Capacity Factor (%)												
37	Monticello - Monthly Minor Outage Rate (%)												
38	Monticello - Days Offline in Month for Refuelin												
39	Monticello - Refueling Outage Start Date												
40	Monticello - Refueling Outage Start Time (HH.MM												
41	Monticello - Refueling Outage End Date												
42	Monticello - Refueling Outage End Time (HH.MM)												
43	Monticello - Fuel Expense - Dollars												
44	Monticello - Fuel Expense - Cents/MBTU												
45	Monticello - Fuel Expense - Cents/Kwhe												
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities												
47	Prairie Island 1 - Cents/Kwhe - Fuel Services												
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee												
49	Prairie Island 1 - Cents/Kwhe - D&D Fee												
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery												
51	Prairie Island 1 - Cents/Kwhe - Ohter Global Costs												
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G												
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities												
54	Prairie Island 2 - Cents/Kwhe - Fuel Services												
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee												
56	Prairie Island 2 - Cents/Kwhe - D&D Fee												
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery												
58	Prairie Island 2 - Cents/Kwhe - Ohter Global Costs												
59	Prairie Island 2 - Cents/Kwhe - AFUDC and A&G												
60	Monticello - Cents/Kwhe - Fuel Commodities												
61	Monticello - Cents/Kwhe - Fuel Services												
62	Monticello - Cents/Kwhe - DOE Disposal Fee												
63	Monticello - Cents/Kwhe - D&D Fee												
64	Monticello - Cents/Kwhe - End of Life Recovery												
65	Monticello - Cents/Kwhe - Ohter Global Costs												
66	Monticello - Cents/Kwhe - AFUDC and A&G												
67	Prairie Island 1 - EOL Recovery Expense - Dollars												
68	Prairie Island 2 - EOL Recovery Expense - Dollars												
69	Monticello - EOL Recovery Expense - Dollars												

PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Operations - State of Minnesota
Nuclear Fuel Expense (Units noted in row)

[PROTECTED DATA BEGINS

Item ID	Item Description (Q1-2023 02-13-23 10:50:02)	Jan 2026	Feb 2026	Mar 2026	Apr 2026	May 2026	Jun 2026	Jul 2026	Aug 2026	Sep 2026	Oct 2026	Nov 2026	Dec 2026
1	Prairie Island 1 - Heat Generation (1000 MBTU)												
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)												
3	Prairie Island 1 - Maximum Capacity (MWe-Net)												
4	Prairie Island 1 - Current Capability (MWe-Net)												
5	Prairie Island 1 - Thermal Capability (MWth)												
6	Prairie Island 1 - Monthly Capacity Factor (%)												
7	Prairie Island 1 - Monthly Minor Outage Rate (%)												
8	Prairie Island 1 - Days Offline in Month for Refuelin												
9	Prairie Island 1 - Refueling Outage Start Date												
10	Prairie Island 1 - Refueling Outage Start Time (HH.MM												
11	Prairie Island 1 - Refueling Outage End Date												
12	Prairie Island 1 - Refueling Outage End Time (HH.MM)												
13	Prairie Island 1 - Fuel Expense - Dollars												
14	Prairie Island 1 - Fuel Expense - Cents/MBTU												
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe												
16	Prairie Island 2 - Heat Generation (1000 MBTU)												
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
18	Prairie Island 2 - Maximum Capacity (MWe-Net)												
19	Prairie Island 2 - Current Capability (MWe-Net)												
20	Prairie Island 2 - Thermal Capability (MWth)												
21	Prairie Island 2 - Monthly Capacity Factor (%)												
22	Prairie Island 2 - Monthly Minor Outage Rate (%)												
23	Prairie Island 2 - Days Offline in Month for Refuelin												
24	Prairie Island 2 - Refueling Outage Start Date												
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM												
26	Prairie Island 2 - Refueling Outage End Date												
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)												
28	Prairie Island 2 - Fuel Expense - Dollars												
29	Prairie Island 2 - Fuel Expense - Cents/MBTU												
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
32	Monticello - Net Electric Generation (MWHe-Net)												
33	Monticello - Maximum Capacity (MWe-Net)												
34	Monticello - Current Capability (MWe-Net)												
35	Monticello - Thermal Capability (MWth)												
36	Monticello - Monthly Capacity Factor (%)												
37	Monticello - Monthly Minor Outage Rate (%)												
38	Monticello - Days Offline in Month for Refuelin												
39	Monticello - Refueling Outage Start Date												
40	Monticello - Refueling Outage Start Time (HH.MM												
41	Monticello - Refueling Outage End Date												
42	Monticello - Refueling Outage End Time (HH.MM)												
43	Monticello - Fuel Expense - Dollars												
44	Monticello - Fuel Expense - Cents/MBTU												
45	Monticello - Fuel Expense - Cents/Kwhe												
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities												
47	Prairie Island 1 - Cents/Kwhe - Fuel Services												
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee												
49	Prairie Island 1 - Cents/Kwhe - D&D Fee												
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery												
51	Prairie Island 1 - Cents/Kwhe - Ohter Global Costs												
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G												
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities												
54	Prairie Island 2 - Cents/Kwhe - Fuel Services												
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee												
56	Prairie Island 2 - Cents/Kwhe - D&D Fee												
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery												
58	Prairie Island 2 - Cents/Kwhe - Ohter Global Costs												
59	Prairie Island 2 - Cents/Kwhe - AFUDC and A&G												
60	Monticello - Cents/Kwhe - Fuel Commodities												
61	Monticello - Cents/Kwhe - Fuel Services												
62	Monticello - Cents/Kwhe - DOE Disposal Fee												
63	Monticello - Cents/Kwhe - D&D Fee												
64	Monticello - Cents/Kwhe - End of Life Recovery												
65	Monticello - Cents/Kwhe - Ohter Global Costs												
66	Monticello - Cents/Kwhe - AFUDC and A&G												
67	Prairie Island 1 - EOL Recovery Expense - Dollars												
68	Prairie Island 2 - EOL Recovery Expense - Dollars												
69	Monticello - EOL Recovery Expense - Dollars												

PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company Docket No. E002/AA-23-153
Electric Operations - State of Minnesota Petition
Nuclear Fuel Expense (Units noted in row) Part E, Attachment 6

[PROTECTED DATA BEGINS

Item ID	Item Description (Q1-2023 02-13-23 10:50:02)	Jan 2027	Feb 2027	Mar 2027	Apr 2027	May 2027	Jun 2027	Jul 2027	Aug 2027	Sep 2027	Oct 2027	Nov 2027	Dec 2027
1	Prairie Island 1 - Heat Generation (1000 MBTU)												
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)												
3	Prairie Island 1 - Maximum Capacity (MWe-Net)												
4	Prairie Island 1 - Current Capability (MWe-Net)												
5	Prairie Island 1 - Thermal Capability (MWth)												
6	Prairie Island 1 - Monthly Capacity Factor (%)												
7	Prairie Island 1 - Monthly Minor Outage Rate (%)												
8	Prairie Island 1 - Days Offline in Month for Refuelin												
9	Prairie Island 1 - Refueling Outage Start Date												
10	Prairie Island 1 - Refueling Outage Start Time (HH.MM												
11	Prairie Island 1 - Refueling Outage End Date												
12	Prairie Island 1 - Refueling Outage End Time (HH.MM)												
13	Prairie Island 1 - Fuel Expense - Dollars												
14	Prairie Island 1 - Fuel Expense - Cents/MBTU												
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe												
16	Prairie Island 2 - Heat Generation (1000 MBTU)												
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
18	Prairie Island 2 - Maximum Capacity (MWe-Net)												
19	Prairie Island 2 - Current Capability (MWe-Net)												
20	Prairie Island 2 - Thermal Capability (MWth)												
21	Prairie Island 2 - Monthly Capacity Factor (%)												
22	Prairie Island 2 - Monthly Minor Outage Rate (%)												
23	Prairie Island 2 - Days Offline in Month for Refuelin												
24	Prairie Island 2 - Refueling Outage Start Date												
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM												
26	Prairie Island 2 - Refueling Outage End Date												
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)												
28	Prairie Island 2 - Fuel Expense - Dollars												
29	Prairie Island 2 - Fuel Expense - Cents/MBTU												
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
32	Monticello - Net Electric Generation (MWHe-Net)												
33	Monticello - Maximum Capacity (MWe-Net)												
34	Monticello - Current Capability (MWe-Net)												
35	Monticello - Thermal Capability (MWth)												
36	Monticello - Monthly Capacity Factor (%)												
37	Monticello - Monthly Minor Outage Rate (%)												
38	Monticello - Days Offline in Month for Refuelin												
39	Monticello - Refueling Outage Start Date												
40	Monticello - Refueling Outage Start Time (HH.MM												
41	Monticello - Refueling Outage End Date												
42	Monticello - Refueling Outage End Time (HH.MM)												
43	Monticello - Fuel Expense - Dollars												
44	Monticello - Fuel Expense - Cents/MBTU												
45	Monticello - Fuel Expense - Cents/Kwhe												
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities												
47	Prairie Island 1 - Cents/Kwhe - Fuel Services												
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee												
49	Prairie Island 1 - Cents/Kwhe - D&D Fee												
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery												
51	Prairie Island 1 - Cents/Kwhe - Ohter Global Costs												
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G												
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities												
54	Prairie Island 2 - Cents/Kwhe - Fuel Services												
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee												
56	Prairie Island 2 - Cents/Kwhe - D&D Fee												
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery												
58	Prairie Island 2 - Cents/Kwhe - Ohter Global Costs												
59	Prairie Island 2 - Cents/Kwhe - AFUDC and A&G												
60	Monticello - Cents/Kwhe - Fuel Commodities												
61	Monticello - Cents/Kwhe - Fuel Services												
62	Monticello - Cents/Kwhe - DOE Disposal Fee												
63	Monticello - Cents/Kwhe - D&D Fee												
64	Monticello - Cents/Kwhe - End of Life Recovery												
65	Monticello - Cents/Kwhe - Ohter Global Costs												
66	Monticello - Cents/Kwhe - AFUDC and A&G												
67	Prairie Island 1 - EOL Recovery Expense - Dollars												
68	Prairie Island 2 - EOL Recovery Expense - Dollars												
69	Monticello - EOL Recovery Expense - Dollars												

PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Operations - State of Minnesota
Nuclear Fuel Expense (Units noted in row)

[PROTECTED DATA BEGINS

Item ID	Item Description (Q1-2023 02-13-23 10:50:02)	Jan 2028	Feb 2028	Mar 2028	Apr 2028	May 2028	Jun 2028	Jul 2028	Aug 2028	Sep 2028	Oct 2028	Nov 2028	Dec 2028
1	Prairie Island 1 - Heat Generation (1000 MBTU)												
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)												
3	Prairie Island 1 - Maximum Capacity (MWe-Net)												
4	Prairie Island 1 - Current Capability (MWe-Net)												
5	Prairie Island 1 - Thermal Capability (MWth)												
6	Prairie Island 1 - Monthly Capacity Factor (%)												
7	Prairie Island 1 - Monthly Minor Outage Rate (%)												
8	Prairie Island 1 - Days Offline in Month for Refuelin												
9	Prairie Island 1 - Refueling Outage Start Date												
10	Prairie Island 1 - Refueling Outage Start Time (HH.MM												
11	Prairie Island 1 - Refueling Outage End Date												
12	Prairie Island 1 - Refueling Outage End Time (HH.MM)												
13	Prairie Island 1 - Fuel Expense - Dollars												
14	Prairie Island 1 - Fuel Expense - Cents/MBTU												
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe												
16	Prairie Island 2 - Heat Generation (1000 MBTU)												
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
18	Prairie Island 2 - Maximum Capacity (MWe-Net)												
19	Prairie Island 2 - Current Capability (MWe-Net)												
20	Prairie Island 2 - Thermal Capability (MWth)												
21	Prairie Island 2 - Monthly Capacity Factor (%)												
22	Prairie Island 2 - Monthly Minor Outage Rate (%)												
23	Prairie Island 2 - Days Offline in Month for Refuelin												
24	Prairie Island 2 - Refueling Outage Start Date												
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM												
26	Prairie Island 2 - Refueling Outage End Date												
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)												
28	Prairie Island 2 - Fuel Expense - Dollars												
29	Prairie Island 2 - Fuel Expense - Cents/MBTU												
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
32	Monticello - Net Electric Generation (MWHe-Net)												
33	Monticello - Maximum Capacity (MWe-Net)												
34	Monticello - Current Capability (MWe-Net)												
35	Monticello - Thermal Capability (MWth)												
36	Monticello - Monthly Capacity Factor (%)												
37	Monticello - Monthly Minor Outage Rate (%)												
38	Monticello - Days Offline in Month for Refuelin												
39	Monticello - Refueling Outage Start Date												
40	Monticello - Refueling Outage Start Time (HH.MM												
41	Monticello - Refueling Outage End Date												
42	Monticello - Refueling Outage End Time (HH.MM)												
43	Monticello - Fuel Expense - Dollars												
44	Monticello - Fuel Expense - Cents/MBTU												
45	Monticello - Fuel Expense - Cents/Kwhe												
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities												
47	Prairie Island 1 - Cents/Kwhe - Fuel Services												
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee												
49	Prairie Island 1 - Cents/Kwhe - D&D Fee												
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery												
51	Prairie Island 1 - Cents/Kwhe - Ohter Global Costs												
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G												
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities												
54	Prairie Island 2 - Cents/Kwhe - Fuel Services												
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee												
56	Prairie Island 2 - Cents/Kwhe - D&D Fee												
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery												
58	Prairie Island 2 - Cents/Kwhe - Ohter Global Costs												
59	Prairie Island 2 - Cents/Kwhe - AFUDC and A&G												
60	Monticello - Cents/Kwhe - Fuel Commodities												
61	Monticello - Cents/Kwhe - Fuel Services												
62	Monticello - Cents/Kwhe - DOE Disposal Fee												
63	Monticello - Cents/Kwhe - D&D Fee												
64	Monticello - Cents/Kwhe - End of Life Recovery												
65	Monticello - Cents/Kwhe - Ohter Global Costs												
66	Monticello - Cents/Kwhe - AFUDC and A&G												
67	Prairie Island 1 - EOL Recovery Expense - Dollars												
68	Prairie Island 2 - EOL Recovery Expense - Dollars												
69	Monticello - EOL Recovery Expense - Dollars												

PROTECTED DATA ENDS]

2025 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,422	3,782,265	79.16%
February	6,058	3,406,191	83.67%
March	5,783	3,524,799	81.92%
April	5,274	3,119,503	82.16%
May	6,941	3,341,530	64.71%
June	8,457	3,779,952	62.08%
July	9,126	4,313,246	63.53%
August	8,759	4,120,706	63.24%
September	7,708	3,465,062	62.44%
October	5,717	3,317,260	77.99%
November	5,776	3,309,649	79.59%
December	6,166	3,684,996	80.33%
Annual	**9,126**	**43,165,159**	**53.85%**

2026 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,402	3,788,813	79.55%
February	6,046	3,416,026	84.07%
March	5,774	3,534,942	82.29%
April	5,241	3,131,424	82.99%
May	6,961	3,357,427	64.83%
June	8,469	3,793,183	62.21%
July	9,136	4,328,005	63.67%
August	8,775	4,130,596	63.27%
September	7,709	3,473,443	62.58%
October	5,700	3,324,149	78.39%
November	5,756	3,314,329	79.98%
December	6,142	3,685,610	80.66%
Annual	**9,136**	**43,277,948**	**54.08%**

2027 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,381	3,783,560	79.70%
February	6,030	3,411,880	81.29%
March	5,750	3,525,395	82.41%
April	5,186	3,121,134	83.58%
May	6,953	3,343,062	64.63%
June	8,446	3,772,709	62.04%
July	9,106	4,305,063	63.54%
August	8,755	4,105,861	63.03%
September	7,679	3,455,032	62.49%
October	5,657	3,308,671	78.62%
November	5,714	3,300,562	80.23%
December	6,102	3,674,648	80.94%
Annual	**9,106**	**43,107,577**	**54.04%**

2028 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,367	3,788,350	79.97%
February	5,976	3,390,918	81.53%
March	5,739	3,529,323	82.66%
April	5,143	3,121,262	84.28%
May	6,969	3,344,950	64.51%
June	8,453	3,770,542	61.95%
July	9,107	4,300,932	63.47%
August	8,769	4,102,603	62.88%
September	7,680	3,452,848	62.44%
October	5,637	3,309,166	78.90%
November	5,696	3,302,906	80.53%
December	6,084	3,676,024	81.21%
Annual	**9,107**	**43,089,824**	**54.01%**

Estimated Load Management Impact

Summer Peak (MW)

	System Base Peak	Total Load Mgmt/ Load Relief	Net Peak
2024	9,147	887	8,260
2025	9,126	895	8,231
2026	9,136	901	8,235
2027	9,106	904	8,202
2028	9,107	906	8,202

Part F: Modeling and Market Workpapers and Supporting Data
Part F consists of workpapers that are being submitted as live files.

Workpaper 1	PLEXOS Inputs
Workpaper 2	PLEXOS Output
Workpaper 3	Coal Pricing
Workpaper 4	Gas Pricing
Workpaper 5	MISO Charges

Part G: Fuel Forecast Workpapers and Supporting Data
Part G consists of workpapers that are being submitted as live files.

Workpaper 1	Forecast Energy and Peak Demand Summary
Workpaper 2	Hydro Historical
Workpaper 3	Pricing for Hydro PPAs
Workpaper 4	St. Paul Cogen Pricing
Workpaper 5	Benson Recovery
Workpaper 6	NSP Solar Gardens Forecast
Workpaper 7	NSP Solar Gardens Price Forecast
Workpaper 8	NSP Wind Curtailment Cost
Workpaper 9	Forced Outage Calculation for Baseload and Intermediate Plants
Workpaper 10	Renewable*Connect Program

CERTIFICATE OF SERVICE

I, Marie Horner, hereby certify that I have this day served copies 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

xx electronic filing

Docket No. **E002/AA-23-153**
E002/GR-15-826
E002/GR-21-630
MISCELLANEOUS ELECTRIC

Dated this 1st day of May 2023

/s/
____
Marie Horner
Regulatory Administrator

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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
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