414 Nicollet Mall
Minneapolis, Minnesota 55401

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NOT PUBLIC DATA HAS BEEN EXCISED

April 30, 2021

—VIA ELECTRONIC FILING—

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

RE: PETITION
2022 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES
DOCKET NO. E002/AA-21-295

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 2022.

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.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and served copies of the summary on the parties on the attached service lists.

If you have any questions regarding this filing please contact Martha Hoschmiller at martha.e.hoschmiller@xcelenergy.com or me at lisa.r.peterson@xcelenergy.com.

Sincerely,

/s/

LISA R. PETERSON
MANAGER, REGULATORY ANALYSIS

Enclosures
c: Service List

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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 2022 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-21-295

PETITION

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Petition requesting approval of the 2022 Annual Fuel Forecast and resulting proposed monthly fuel cost charges for the months of January-December 2022. 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.

This is the Company's third forecast filing in connection with the Fuel Clause Reform pilot process.[2] We continue to refine the presentation of the forecast in this Petition to address feedback received from the Department of Commerce and the Commission in past Fuel Forecast proceedings, and we expect to continue to work with stakeholders to make this process as efficient and effective as possible.

As discussed below, this Petition requests approval to implement specific fuel clause rates by month and customer class throughout 2022. 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] Orders dated December 17, 2017, December 12, 2018, and June 12, 2019.
[2] The 2021 Fuel Forecast was approved by the Commission's December 20, 2020 Order in Docket No. E002/AA-20-417.

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 2022. Specifically, we discuss the following:

- The background leading to the fuel clause reform process, our proposed fuel cost charges for 2022, 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 purchase 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. SUMMARY OF FILING

Pursuant to Minn. R. 7829.1300, subp. 1, a one-paragraph summary of the filing accompanies this petition.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. R. 7829.1300, subp. 2, the Company has electronically filed this document with the Minnesota Public Utilities Commission, and served it on the attached service lists. 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

Matt Harris
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401-8th Floor
Minneapolis, MN 55401
(612) 330-7641

C. Date of Filing and Proposed Effective Date of Rates

The date of this filing is April 30, 2021. The Company's Petition proposes different monthly fuel cost charges for each month of the year 2022, and we propose to implement the monthly rate changes on the first day of each month for the 12 months beginning January 1, 2022. In order to provide customers 30 days' notice of the January 1, 2022 rate, we request that an Order be issued in this docket by November 30, 2021.

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, 2021, Reply Comments are due on July 30, 2021 and Response Comments are due on August 30, 2021. A Commission Order is expected by November 27, 2021. The Company plans to update inputs with more current information in the July 31 Reply Comments.

E. Utility Employee Responsible for Filing

Lisa Peterson
Manager, Regulatory 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:

Matt Harris
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401-8th Floor
Minneapolis, MN 55401
matt.b.harris@xcelenergy.com

Lynnette Sweet
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. Sweet at the Regulatory Records email address above.

V. 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 currently in place 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, 2021, Reply Comments are due on July 30, 2021, and Response Comments are due on August 30, 2021. A Commission Order is expected by November 30, 2021 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

Table 1 below shows the specific rates we request be implemented by month and by customer class as determined by our fuel forecast for 2022.

Table 1: Proposed 2022 Monthly Fuel Clause Rates by Customer Class ($/kWh)

Month	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
January	$0.02480	$0.02512	$0.02434	$0.03041	$0.01992	$0.01946
February	$0.03012	$0.03050	$0.02955	$0.03695	$0.02417	$0.02361
March	$0.03029	$0.03067	$0.02972	$0.03716	$0.02431	$0.02375
April	$0.03059	$0.03097	$0.03001	$0.03751	$0.02456	$0.02399
May	$0.03312	$0.03353	$0.03249	$0.04062	$0.02659	$0.02597
June	$0.03880	$0.03929	$0.03807	$0.04760	$0.03114	$0.03042
July	$0.03258	$0.03299	$0.03196	$0.03998	$0.02614	$0.02553
August	$0.03281	$0.03322	$0.03218	$0.04026	$0.02632	$0.02570
September	$0.03238	$0.03279	$0.03177	$0.03972	$0.02600	$0.02539
October	$0.03026	$0.03064	$0.02969	$0.03712	$0.02429	$0.02372
November	$0.02764	$0.02799	$0.02712	$0.03391	$0.02218	$0.02167
December	$0.02564	$0.02596	$0.02515	$0.03144	$0.02058	$0.02010

We will update the Company web site with the full year of monthly fuel cost charges by December 1, 2021, or upon issuance of the Commission's Order. 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.

VI. 2022 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 2022 shown in Table 1 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, below, we discuss the drivers of the changes in costs for the 2022 test year and how we used the forecast to determine the rates shown above in Table 1. More detail about the PLEXOS software modeling is described in Part B, Attachment 1.

A. 2022 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 and 3.

iii. Company-Owned Wind Generation

Inputs for NSP-owned wind generation in the PLEXOS model reflect the individual hourly profiles of each NSP-owned project. These profiles are based on specific historical results for projects with an annual generation profile based on at least twelve months of operational data. 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. 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.

In the past, coal plants have been offered into the MISO market as "must-run" generation plants because it was the most cost-effective way to operate the plants and because of the operational limitations of coal plants. However, with the changes over time in our energy supply, we are now able to offer most of these units on an "economic" basis, which allows MISO to de-commit the units if other sources of energy are more cost effective. This typically happens when renewable generation is forecasted to be high, loads are forecasted to be low, and natural gas prices are low in addition to high combined cycle plant availability. For this reason, the coal units, King, Sherco 2, and Sherco 3 are now set as economic commit in the PLEXOS model to reflect this operational change during periods in which they are available. In addition, consistent with our petition in Docket No. E002/M-19-809, in which we received approval to seasonally operate the King and Sherco 2 plants, these plants are only available to operate in the months of January, February, June, July, August and December in the PLEXOS model.

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 spot 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.

v. Company-Owned Wood/RDF Generation

Each NSP-owned wood/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 10. Estimated costs for planned and forced outages are summarized in Part B, Attachment 7. Natural gas fuel prices are forecast 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 10. 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 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 10. 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 2022 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 7 and 8.

x. *Purchased Wind Generation*

Wind PPAs modeled in the PLEXOS simulation reflect the hourly profiles for each individual project. For existing PPAs, these profiles are based on historical results from the projects' specific operational data. For new PPAs, 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. Some small wind PPAs are aggregated into single groups for modeling purposes in consideration of simulation run times and the limited value provided by individual modeling for these non-dispatchable resources. Projects for which the Company can allow MISO to curtail output are modeled as curtailable projects. Those 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.

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

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

applicable, supporting calculations have been included with the filing in Part G, Workpapers 2, 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 that represent 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 2022 are **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** and are reflected in the Net System Costs shown at line 35 of Part A, Attachment 1, page 1 of 2. 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 forecast of hourly price is developed is included with the filing as Part B, Attachment 8.

xiii. Other FCA Costs

There are other costs that flow through the 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 and 6.
    - 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.

[4] Recovery was approved by Commission Order on January 23, 2018 in Docket No. E002/M-17-530.

  - Laurentian Energy Authority I, LLC – Early termination of agreement covering the purchase of generation from wood fueled biomass facilities.[5]

- 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 historical actual costs and revenues observed for these MISO charge types. A summary of MISO charges included in the 2022 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 2022 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.
- Wind curtailment costs are estimated based on observed curtailment for prior years where large additions of wind generation preceded transmission expansion or transmission outages were higher than normal due to transmission expansion activity. Specifically, we based the 2022 wind curtailment estimate on the average curtailment percentage for years 2003 – 2020, adjusted to remove the highest curtailment year (greater than 10 percent) and the lowest curtailment years (less than 3 percent). We projected 2022 MWh production for each PPA wind farm that will be eligible for curtailment payments in 2022 using the average historical MWh for the years 2015-2020. For projects that are not yet in-service or only recently placed in-service, we used capacity factors based on the wind patterns discussed in Part B, Attachment 10. Total projected curtailment costs were determined by multiplying the curtailment percentage by the projects' MWh production for each project and by the PPA cost per MWh.

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[5] Recovery was approved by Commission Order on January 23, 2018 in Docket No. E002/M-17-551.

A spreadsheet detailing the historical data and the calculation of the average is included with the filing in Part G, Workpaper 9.

xiv. FCA Exclusions

PPAs that serve the Renewable*Connect program are included in the PLEXOS model.[6] Renewable*Connect Pilot Program currently uses a portion of one wind PPA and one solar PPA to serve participant customer sales. Renewable*Connect Month-to-Month (MTM) uses a pool of resources that includes projects that formerly served 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. We note that the Windsource program will close in early 2022 and subscribers will be moved to Renewable*Connect MTM, so we will no longer show separate data for Windsource resources and subscribers in our fuel forecast beginning in 2022. Support for the Renewable*Connect forecast is found in Part G, Workpaper 11.

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 30 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.

[6] Recovery of Renewable*Connect Pilot Program was approved by Commission Order on February 27, 2017 in Docket No. E002/M-15-985. Recovery of Renewable*Connect Month-to-Month was approved by Commission Order on August 12, 2019 in Docket No. E002/M-19-33.

B. Test Year Drivers

Total FCA costs for the MN jurisdiction are forecast to increase by over $55 million from FCA costs authorized by the Commission for 2021. There are several key drivers that affect the Company's forecast for fuel and purchased energy costs in the 2022 test year. Two of these drivers—wind expansion and lower coal generation due to increased economic offers in the market—place downward pressure on the forecast, while three—projected increases in the Solar*Rewards Community program, increase in purchases from Manitoba Hydro, and higher MISO costs—add upward pressure.

The 2022 test year reflects completion of the latest round of wind generation expansion for the NSP system. The Dakota Range owned wind project is expected to go into service by the end of 2021. In addition, the next phase of wind upgrades begins with the repower of the owned Nobles wind project in late 2022. Lastly, two PPA wind farms (Deuel Harvest and Heartland Divide) and one PPA solar project (Elk Creek solar bridge PPA) are also expected to be in service by the end of 2021. These wind projects are either reflected at zero fuel cost generation, as in the case of owned wind, or low cost PPA wind. The addition of a large amount of low-cost wind generation places downward pressure on the forecast for the 2022 test year. Note that 100 percent of the generation from Deuel Harvest and Elk Creek solar is assigned to the Renewable*Connect program, while 25 percent of Heartland Divide is assigned to the Renewable*Connect program, leaving the remaining 75 percent of this low cost PPA available for the NSP system.

Coal generation is forecast to decline significantly for 2022 reflecting the change in operational strategy of utilizing economic offers in the MISO market for King, Sherco 2 and Sherco 3 when these units are available for operation. In addition, the 2022 filing reflects seasonal operations at King and Sherco 2 as approved in Docket No. E002/M-19-809. The decline in coal generation is offset by increases in generation from low cost renewable generation and natural gas generation.

The 2022 test year also includes projected increases in the Solar*Rewards Community program. This program is expected to increase in size by seven percent and contribute almost $11 million of additional cost in 2022. Partially offsetting the increase in program size and cost is a 1.6 percent decrease in the average program cost to $127.29/MWh driven by an increase in program participants on the lower Value of Solar (VOS) rate. The above market cost of the program is forecast to increase by over $10 million and results in an annual Fuel Clause Adjustment (FCA) rate for Minnesota customers that is $6.28/MWh or 26 percent higher than the rate would be without this program.

An expansion of our agreements with Manitoba Hydro that began in May 2021 is in service for the full 2022 forecast year contributing **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** to higher forecast costs for 2022. The Commission approved the PPA with Manitoba Hydro in its May 26, 2011 Order in Docket No. E002/M-10-633.

MISO costs are also forecast to **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for 2022. The forecast of these costs is based on historical data which has shown **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].** Part B, Attachment 9 shows the MISO costs by category and Part F, Workpaper 5 provides further details on the calculation of the forecast costs for 2022.

C. Customer Class Rate Calculation

To determine the proposed monthly fuel cost by customer class, we take the 2022 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 2022 actual fuel costs:

- Elk Creek Solar PPA (Docket No. E002/M-19-568) – proposed amendment
- Renewable Connect (Docket No. E002/M-21-222) – limited program modifications and updated pricing

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

VII. 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 appropriately hedged 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 hedge against congestion risk. The Company periodically reviews its FTR portfolio to ensure that it is properly hedged 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. ANR Pipeline storage is projected to cover approximately 32 percent of the 2019-2020 winter gas generation requirements. The Company's storage service with NNG was converted to a new service requested by NSP specifically for electric generation customers effective June 1, 2018. Through this conversion, NSP now 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 such a significant portion of system requirements covered through the use of storage, the Company does not use financial instruments to hedge natural gas.

VIII. 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:

- Order Item 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 March 1 True-Up filings.

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.

IX. 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

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

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, 2021 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 2020 period (Docket No. E999/AA-19-293). We will update Part D in our March 1, 2022 True-Up filing as necessary to reflect any changes between the 2021 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 Fuel Adjustment Factor (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 Table 1 and Part A, Attachment 1 of this Petition for the monthly fuel cost charges we propose to implement in 2022.

C. 7825.2830 Annual Five-Year Projection

The fuel cost forecast summarized per unit, cost and energy for the 2022 test year is provided in Part A, Attachments 1 – 3. The monthly projection of fuel cost by energy source for the 2022 test year is provided as Part B, Attachments 2 – 4.

The fuel cost forecast summarized per unit, cost and energy for the four years beyond the 2022 test year is provided in Part E, Attachments 1 – 3. The monthly projection of fuel cost by energy source for the four years beyond the 2022 test year is provided as Part E, Attachments 4 – 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 notice to all intervenors in our 2013 and 2015 electric rate cases who have requested to remain on the docket service lists.

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

CONCLUSION

Xcel Energy respectfully requests the Commission approve our 2022 Annual Fuel Forecast, resulting proposed monthly fuel cost charges for the months of January-December 2022, and corresponding proposed tariff revision reflecting the monthly fuel cost charges.

Dated: April 30, 2021

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	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2022 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-21-295

PETITION

SUMMARY

Please take notice that on April 30, 2021 Northern States Power Company, doing business as Xcel Energy, submitted to the Minnesota Public Utilities Commission a Petition for approval of our 2022 Annual Fuel Forecast and resulting proposed monthly fuel cost charges for the months of January-December 2022 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 2022 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-21-295

NOTICE OF REPORT AVAILABILITY

On April 30, 2021, 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 2022 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 – 5 and Part G, Workpapers 3, 4, 6, 7, 8, 9, 10, and 11 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 2021.

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 2022 - Dec 2022

Protected Data is shaded.

Line #	Updated 4-1-2021													
1	*Costs in $1,000's*	1/1/2022	2/1/2022	3/1/2022	4/1/2022	5/1/2022	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	11/1/2022	12/1/2022	2022 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	$9,148	$12,913	$18,038	$20,576	$23,802	$20,816	$24,489	$23,331	$16,859	$13,603	$9,432	$7,729	$200,737
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**	($6,982)	($10,707)	($15,640)	($17,608)	($20,042)	($17,500)	($19,534)	($18,513)	($14,373)	($11,902)	($8,093)	($6,336)	($167,231)
31	**Less Renewable Connect Pilot**													
32	**Less Renewable Connect MTM**													
33	**Less Renewable Connect LT**													
34														
35	**Net System Costs**													
36														
37	**Net System Sales**													
38	Calendar Month MWh Sales													
39														
40	**Less Renewable Connect Pilot MWh Sales**													
41	**Less Renewable Connect MTM MWh Sales**													
42	**Less Renewable Connect LT MWh Sales**													
43														
44	**Net Sys MWh Sales**													37,656,109
45														
46	**System Cost in cents/kWh**													
47														
48	**Minnesota Juris. MWh Sales**													
49														
50	**Less Renewable Connect Pilot MWh Sales**													
51	**Less Renewable Connect MTM MWh Sales**													
52	**Less Renewable Connect LT MWh Sales**													
53														
54	**Net MN MWh Sales**													26,631,660
55														
56	**MN Fuel Cost**													
57	**Solar Gardens - Above Market Cost**	$6,982	$10,707	$15,640	$17,608	$20,042	$17,500	$19,534	$18,513	$14,373	$11,902	$8,093	$6,336	$167,231
58	**Laurentian Buyout costs**													
59	**Pine Bend Buyout Cost**													
60	**Benson Buyout Cost**													
61														
62	**Forecast MN FCA Costs**													$805,608
63														
64														
65	**Forecast MN FCA Cost in cents/kWh**													**3.025**
66														
67														
68	**Forecast MN FCA Cost in $/MWh**													30.25

PROTECTED DATA ENDS]

Proposed 2022 Monthly Fuel Clause Charges ($/KWh)

	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
January	$0.02480	$0.02512	$0.02434	$0.03041	$0.01992	$0.01946
February	$0.03012	$0.03050	$0.02955	$0.03695	$0.02417	$0.02361
March	$0.03029	$0.03067	$0.02972	$0.03716	$0.02431	$0.02375
April	$0.03059	$0.03097	$0.03001	$0.03751	$0.02456	$0.02399
May	$0.03312	$0.03353	$0.03249	$0.04062	$0.02659	$0.02597
June	$0.03880	$0.03929	$0.03807	$0.04760	$0.03114	$0.03042
July	$0.03258	$0.03299	$0.03196	$0.03998	$0.02614	$0.02553
August	$0.03281	$0.03322	$0.03218	$0.04026	$0.02632	$0.02570
September	$0.03238	$0.03279	$0.03177	$0.03972	$0.02600	$0.02539
October	$0.03026	$0.03064	$0.02969	$0.03712	$0.02429	$0.02372
November	$0.02764	$0.02799	$0.02712	$0.03391	$0.02218	$0.02167
December	$0.02564	$0.02596	$0.02515	$0.03144	$0.02058	$0.02010

Northern States Power Company
Electric Utility - State of Minnesota
Monthly Fuel Clause Charge January 2022 - December 2022

Protected Data is shaded.

Month Fuel Cost Charges Applied to Customer Billing	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	12 Months
FORECASTED COST OF FUEL													
	[PROTECTED DATA BEGINS												
[1] Forecasted MN Cost in $1,000's													**$805,608**
[2] Forecasted Minn. Retail Sales Subject to FCC *													26,631,660
[3] Forecasted MN Cost in cents/kWh [1]/[2]*100													**3.025¢**
												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
2022 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													26,631,660
2022 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]													$804,661
[30] **2022 Cost vs Revenue Diff in $1,000's** [1]-[29]													
[31] **2022 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]
2022 Proposed Monthly Fuel Cost Charges in $/kWh													
[34] **Residential** [10]/100+[33]/100	**$0.02480**	**$0.03012**	**$0.03029**	**$0.03059**	**$0.03312**	**$0.03880**	**$0.03258**	**$0.03281**	**$0.03238**	**$0.03026**	**$0.02764**	**$0.02564**	
[35] **C & I Non-Demand** [11]/100+[33]/100	**$0.02512**	**$0.03050**	**$0.03067**	**$0.03097**	**$0.03353**	**$0.03929**	**$0.03299**	**$0.03322**	**$0.03279**	**$0.03064**	**$0.02799**	**$0.02596**	
[36] **C & I Demand Non-TOD** [12]/100+[33]/100	**$0.02434**	**$0.02955**	**$0.02972**	**$0.03001**	**$0.03249**	**$0.03807**	**$0.03196**	**$0.03218**	**$0.03177**	**$0.02969**	**$0.02712**	**$0.02515**	
[37] **C & I Demand TOD On-Peak** [13]/100+[33]/100	**$0.03041**	**$0.03695**	**$0.03716**	**$0.03751**	**$0.04062**	**$0.04760**	**$0.03998**	**$0.04026**	**$0.03972**	**$0.03712**	**$0.03391**	**$0.03144**	
[38] **C & I Demand TOD Off-Peak** [14]/100+[33]/100	**$0.01992**	**$0.02417**	**$0.02431**	**$0.02456**	**$0.02659**	**$0.03114**	**$0.02614**	**$0.02632**	**$0.02600**	**$0.02429**	**$0.02218**	**$0.02058**	
[39] **Outdoor Lighting** [15]/100+[33]/100	**$0.01946**	**$0.02361**	**$0.02375**	**$0.02399**	**$0.02597**	**$0.03042**	**$0.02553**	**$0.02570**	**$0.02539**	**$0.02372**	**$0.02167**	**$0.02010**	

* Excluded Renewable*Connect MWh

2022 Proposed Costs verses Revenues													
2022 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]													$805,608
[47] Total Forecasted MN Costs [1]													$805,608
[48] **2022 Cost vs Revenue Diff in $1,000's** [47]-[46]													$0
													PROTECTED DATA ENDS]

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Northern States Power Company
Electric Utility - State of Minnesota

Jan 2022 - Dec 2022

Protected Data is shaded.

Line #	Updated 4-1-2021													
1	*Energy in GWhs*	**1/1/2022**	**2/1/2022**	**3/1/2022**	**4/1/2022**	**5/1/2022**	**6/1/2022**	**7/1/2022**	**8/1/2022**	**9/1/2022**	**10/1/2022**	**11/1/2022**	**12/1/2022**	**2022 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	71.9	101.4	141.7	161.6	187.0	163.5	192.4	183.3	132.4	106.9	74.1	60.7	1,577.0
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 GWh**													
31	**Less Renewable Connect LT GWh**													
32														
33	**Net System GWh**													41,042.8

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota

Jan 2022 - Dec 2022

Protected Data is shaded.

Line #	Updated 4-1-2021													
1	*$/MWh*	**1/1/2022**	**2/1/2022**	**3/1/2022**	**4/1/2022**	**5/1/2022**	**6/1/2022**	**7/1/2022**	**8/1/2022**	**9/1/2022**	**10/1/2022**	**11/1/2022**	**12/1/2022**	**2022 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	$127.29	$127.29	$127.29	$127.29	$127.29	$127.29	$127.29	$127.29	$127.29	$127.29	$127.29	$127.29	$127.29
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**	$97.15	$105.55	$110.36	$108.93	$107.18	$107.02	$101.54	$101.00	$108.52	$111.38	$109.21	$104.35	$106.04
30	**Less Renewable Connect Pilot**													
31	**Less Renewable Connect MTM**													
32	**Less Renewable Connect LT**													
33														
34	**Net System $/MWh**													$21.20

PROTECTED DATA ENDS]

2022 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	5,824	3,709,939	85.62%
February	5,394	3,224,373	88.95%
March	5,203	3,549,269	91.69%
April	4,774	3,147,692	91.58%
May	5,935	3,319,620	75.18%
June	7,947	3,618,603	63.24%
July	8,992	4,148,511	62.01%
August	8,524	4,021,858	63.42%
September	7,011	3,314,735	65.66%
October	5,208	3,312,623	85.49%
November	5,284	3,238,278	85.11%
December	5,789	3,588,496	83.31%
Annual	**8,992**	**42,193,996**	**53.56%**

Redline

FUEL COST FACTORS (~~2021~~2022) T

Month	Residential	Commercial & Industrial Non-Demand	Commercial & Industrial Demand Non-TOD	Commercial & Industrial Demand On-Peak	Commercial & Industrial Demand Off-Peak	Outdoor Lighting	
January	~~$0.02315~~ $0.02480	~~$0.02344~~ $0.02512	~~$0.02271~~ $0.02434	~~$0.02839~~ $0.03041	~~$0.01859~~ $0.01992	~~$0.01816~~ $0.01946	R
February	~~$0.02613~~ $0.03012	~~$0.02646~~ $0.03050	~~$0.02564~~ $0.02955	~~$0.03206~~ $0.03695	~~$0.02097~~ $0.02417	~~$0.02048~~ $0.02361	
March	~~$0.02716~~ $0.03029	~~$0.02750~~ $0.03067	~~$0.02665~~ $0.02972	~~$0.03332~~ $0.03716	~~$0.02180~~ $0.02431	~~$0.02129~~ $0.02375	
April	~~$0.02854~~ $0.03059	~~$0.02890~~ $0.03097	~~$0.02800~~ $0.03001	~~$0.03500~~ $0.03751	~~$0.02292~~ $0.02456	~~$0.02239~~ $0.02399	
May	~~$0.03236~~ $0.03312	~~$0.03277~~ $0.03353	~~$0.03175~~ $0.03249	~~$0.03970~~ $0.04062	~~$0.02597~~ $0.02659	~~$0.02537~~ $0.02597	
June	~~$0.03617~~ $0.03880	~~$0.03663~~ $0.03929	~~$0.03548~~ $0.03807	~~$0.04438~~ $0.04760	~~$0.02902~~ $0.03114	~~$0.02834~~ $0.03042	~~R~~
July	~~$0.03086~~ $0.03258	~~$0.03125~~ $0.03299	~~$0.03027~~ $0.03196	~~$0.03786~~ $0.03998	~~$0.02476~~ $0.02614	~~$0.02418~~ $0.02553	
August	~~$0.03012~~ $0.03281	~~$0.03049~~ $0.03322	~~$0.02954~~ $0.03218	~~$0.03696~~ $0.04026	~~$0.02416~~ $0.02632	~~$0.02359~~ $0.02570	
September	~~$0.03067~~ $0.03238	~~$0.03106~~ $0.03279	~~$0.03010~~ $0.03177	~~$0.03763~~ $0.03972	~~$0.02462~~ $0.02600	~~$0.02405~~ $0.02539	
October	~~$0.02743~~ $0.03026	~~$0.02777~~ $0.03064	~~$0.02691~~ $0.02969	~~$0.03364~~ $0.03712	~~$0.02201~~ $0.02429	~~$0.02150~~ $0.02372	
November	~~$0.02474~~ $0.02764	~~$0.02505~~ $0.02799	~~$0.02427~~ $0.02712	~~$0.03035~~ $0.03391	~~$0.01985~~ $0.02218	~~$0.01938~~ $0.02167	
December	~~$0.02310~~ $0.02564	~~$0.02339~~ $0.02596	~~$0.02266~~ $0.02515	~~$0.02834~~ $0.03144	~~$0.01854~~ $0.02058	~~$0.01811~~ $0.02010	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:

1. The cost of fuels consumed in the Company's generating stations as recorded in Federal Energy Regulatory Commission (FERC) Accounts 151 and 518.

2. The cost of energy purchases as recorded in FERC Account 555, exclusive of capacity or demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased on an economic dispatch basis.

(Continued on Sheet No. 5-91.2)

3. All Midwest ISO (MISO) costs and revenues authorized by the Commission to flow through this Fuel Clause Rider and excluding MISO costs and revenues that are recoverable in base rates, as prescribed in applicable Commission Orders.

4. All fuel and purchased energy expenses incurred by the Company over the duration of any Commission-approved contract, as provided for by Minnesota Statutes, Section 216B.1645, except any such expenses recovered in base rates or other riders.

(Continued on Sheet No. 5-91.2)

Clean

FUEL COST FACTORS (2022) T

Month	Residential	Commercial & Industrial Non-Demand	Demand Non-TOD	Demand On-Peak	Demand Off-Peak	Outdoor Lighting	
January	$0.02480	$0.02512	$0.02434	$0.03041	$0.01992	$0.01946	R
February	$0.03012	$0.03050	$0.02955	$0.03695	$0.02417	$0.02361	
March	$0.03029	$0.03067	$0.02972	$0.03716	$0.02431	$0.02375	
April	$0.03059	$0.03097	$0.03001	$0.03751	$0.02456	$0.02399	
May	$0.03312	$0.03353	$0.03249	$0.04062	$0.02659	$0.02597	
June	$0.03880	$0.03929	$0.03807	$0.04760	$0.03114	$0.03042	
July	$0.03258	$0.03299	$0.03196	$0.03998	$0.02614	$0.02553	
August	$0.03281	$0.03322	$0.03218	$0.04026	$0.02632	$0.02570	
September	$0.03238	$0.03279	$0.03177	$0.03972	$0.02600	$0.02539	
October	$0.03026	$0.03064	$0.02969	$0.03712	$0.02429	$0.02372	
November	$0.02764	$0.02799	$0.02712	$0.03391	$0.02218	$0.02167	
December	$0.02564	$0.02596	$0.02515	$0.03144	$0.02058	$0.02010	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:

1. The cost of fuels consumed in the Company's generating stations as recorded in Federal Energy Regulatory Commission (FERC) Accounts 151 and 518.

2. The cost of energy purchases as recorded in FERC Account 555, exclusive of capacity or demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased on an economic dispatch basis.

3. All Midwest ISO (MISO) costs and revenues authorized by the Commission to flow through this Fuel Clause Rider and excluding MISO costs and revenues that are recoverable in base rates, as prescribed in applicable Commission Orders.

4. All fuel and purchased energy expenses incurred by the Company over the duration of any Commission-approved contract, as provided for by Minnesota Statutes, Section 216B.1645, except any such expenses recovered in base rates or other riders.

(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

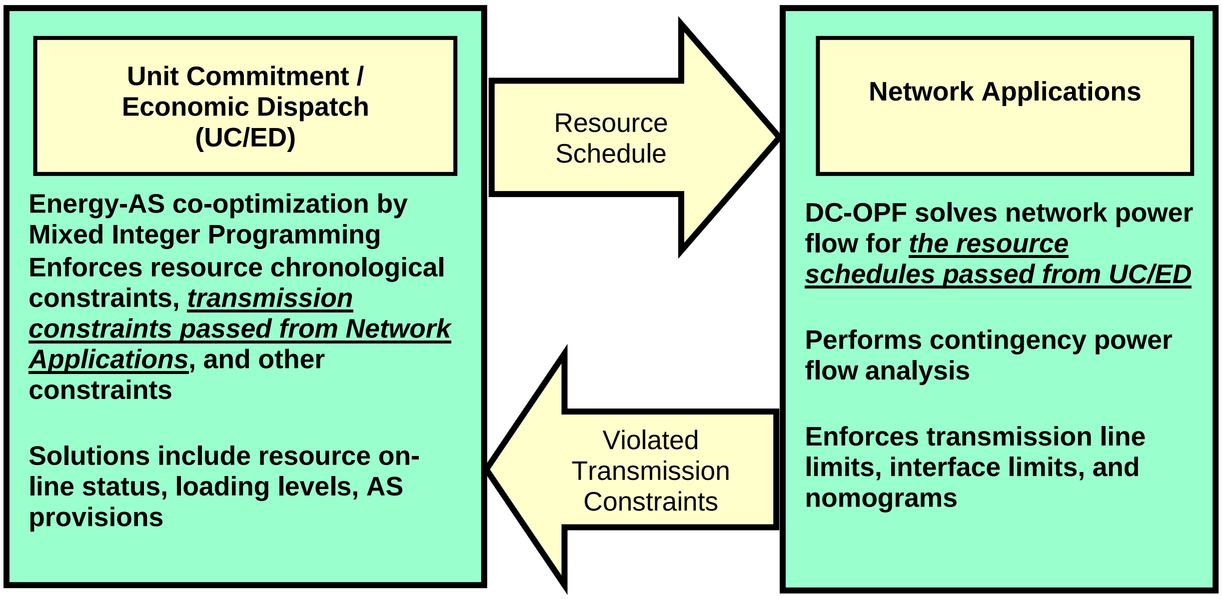
Key to Applications:

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

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Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2022

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Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2022 Total AVG
		[PROTECTED DATA BEGINS												
Allen S King	Coal													
Allen S King	Gas													
Allen S King 1	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	Coal													
Bay Front 5	Gas													
Bay Front 5	Wood													
Bay Front 6	Coal													
Bay Front 6	Gas													
Bay Front 6	Wood													
Bay Front	AVG COST													
Black Dog 25 CC	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	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 CC 1x1	Gas													
High Bridge CC 2x1	Gas													
High Bridge	AVG COST													
Invenergy 1	Gas													
Invenergy 1	Oil													
Invenergy 2	Gas													
Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1F	Oil													
Inver Hills 1G	Gas													
Inver Hills 2F	Oil													
Inver Hills 2G	Gas													
Inver Hills 3F	Oil													
Inver Hills 3G	Gas													
Inver Hills 4F	Oil													
Inver Hills 4G	Gas													
Inver Hills 5F	Oil													
Inver Hills 5G	Gas													
Inver Hills 6F	Oil													
Inver Hills 6G	Gas													
Inver Hills	AVG COST													
LS Power	AVG COST													
MEC I														
MEC II														
MEC	AVG COST													
Red Wing 1	RDF													
Red Wing 1	Gas													
Red Wing 2	RDF													
Red Wing 2	Gas													
Red Wing	AVG COST													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 1	Oil													
Sherburne 2	Coal													
Sherburne 2	Oil													
Sherburne 3	Coal													
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	AVG COST													
Wilmarth 1	RDF													
Wilmarth 1	Gas													
Wilmarth 2	RDF													
Wilmarth 2	Gas													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

PROTECTED DATA ENDS]

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Coal Expense
$/Mbtu
2022

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Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2022
	[PROTECTED DATA BEGINS												
Allen S King 1													
Bay Front 5													
Bay Front 6													
Bay Front AVG													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

PROTECTED DATA ENDS]

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

Docket No. E002/AA-21-295
Petition
Part B, Attachment 4

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[PROTECTED DATA BEGINS

Item ID	Item Description (Q1-2021 04-23-21 09:56:52)	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022
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					
4					
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8					
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36					

PROTECTED DATA ENDS]

	2016	2017	2018	2019	2020		5 Yr Average	ES Adder	Modeled
	[PROTECTED DATA BEGINS								
Monti									
PI1									
PI2									
SHC1									
SHC2									
SHC3									
King									
BD 5/2									
Highbridge									
Riverside									

PROTECTED DATA ENDS]

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[PROTECTED DATA BEGINS

	Unit		MISO Rate
1	Angus Anson 2		
2	Angus Anson 3		
3	Angus Anson 4		
4	Black Dog 6		
5	Blue Lake 1		
6	Blue Lake 2		
7	Blue Lake 3		
8	Blue Lake 4		
9	Blue Lake 7		
10	Blue Lake 8		
11	Inver Hills 1		
12	Inver Hills 2		
13	Inver Hills 3		
14	Inver Hills 4		
15	Inver Hills 5		
16	Inver Hills 6		
17	Wheaton 1		
18	Wheaton 2		
19	Wheaton 3		
20	Wheaton 4		
21	Wheaton 6		

PROTECTED DATA ENDS]

*MISO calculates each unit's Equivalent Forced Outage Rate – Demand (eFORd) based on three-years of history for peaking plants.

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

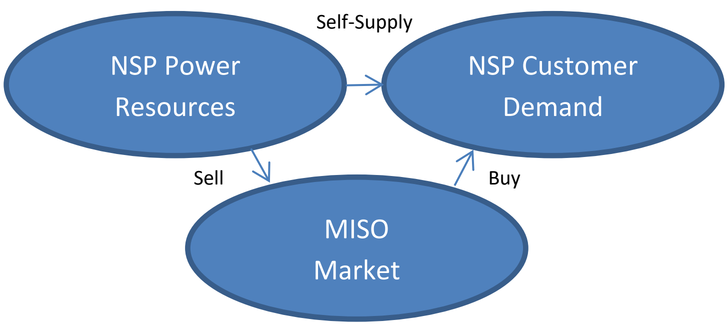
		Planned							Unplanned						
Unit	**Type**	**Outage MWh**	**Replacement Cost ($)**	**Unit Cost ($)**	**Energy Cost Due to Outages ($)**	**Replacement Cost $/MWh**	**Unit Cost $/MWh**	**Outage Cost $/MWh**	**Outage MWh**	**Replacement Cost ($)**	**Unit Cost ($)**	**Energy Cost Due to Outages ($)**	**Replacement 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:

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

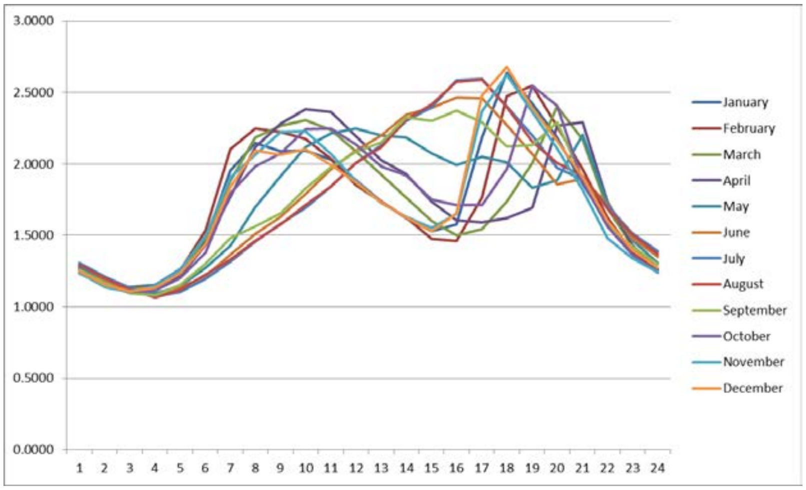
$$P_d^{NG} = Daily\ Natural\ Gas\ Price;\ NL_t = Hourly\ Net\ Load = D_t - W_t$$

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

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

The historical daily price pattern ($S_{1..24}^M$) 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.

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	Category	2022 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

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White Paper:
Typical Meteorological Year (TMY) profile for modeling wind and solar generation on the NSP System

February 2021

Introduction

This paper discusses the process used to select months to create Typical Meteorological Year (TMY) profiles of wind and solar generation for Xcel Energy's upper Midwest region.

Selection of months based on average capacity factor

In the Company's experience, there is a greater variance in the monthly capacity factors for wind generation than for solar generation. Accordingly, the Company chose to base the selection of the month-year combinations for the TMY on wind speed data rather than solar irradiance data. Selection of the months used in the TMY was made by first comparing the wind generation capacity factors for each month-year combination against the average wind generation capacity factor[1] for each month across the years from 2012 through 2020[2]. The TMY months selected were limited to those that have occurred in the last three years. For example, the average capacity factor for all February wind generation for the years 2012 through 2020 was 48.7%. The capacity factors for the last three Februarys (February 2018, 2019 and 2020) were 47.2%, 37.4% and 53.9%, respectively. The capacity factor of 47.2% for February 2018 was closest to the average February capacity factor of 48.7%, so it was chosen for the TMY profile. Actual hourly wind generation from each wind farm for February 2018 was used in the TMY profile. After the initial selection of month-year combinations, the month-year combinations were re-evaluated with an objective of realizing an annual capacity factor for the TMY profile that was approximately 1.5% lower than the average annual capacity factor for the years 2012-2020.[3]

The 2021 Typical Meteorological Year profile includes renewable generation data from 2021 for January, data from 2020 for March, May and July, data from 2019 for

[1] To account for the effect of improving turbine technology increasing capacity factors over time, wind speed data for each month-year combinations was converted to generation using an empirical power curve from a recently built Xcel Energy wind farm. This provided a consistent power conversion across time.
[2] Data from January 2021 was available for this analysis. For all other months, the most recent data was from 2020.
[3] Applying a linear best-fit through weather reanalysis wind speed data converted to generation from 1980 through 2019 results in a line with a slope of -1.5%.

April, August, October, November, and December, and data from 2018 for February, June, and September.

Figure 1 shows the spread between the minimum capacity factor, the average capacity factor, and the maximum capacity factor for each month based on the nine years of hourly wind speed data that the Company used to select the month-year pairs to generation the TMY profiles. As can be seen in Figure 1, the month-year pairs that make up the TMY are representative of the average monthly capacity factors calculated from all nine years of hourly data for each month.

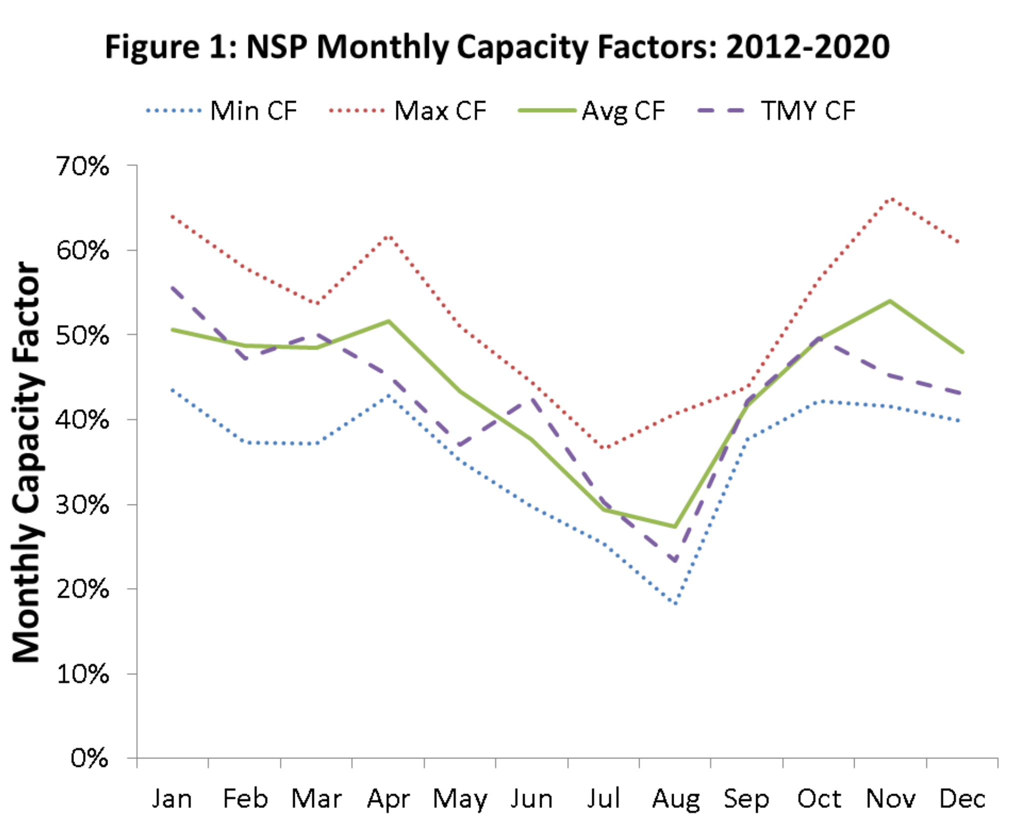
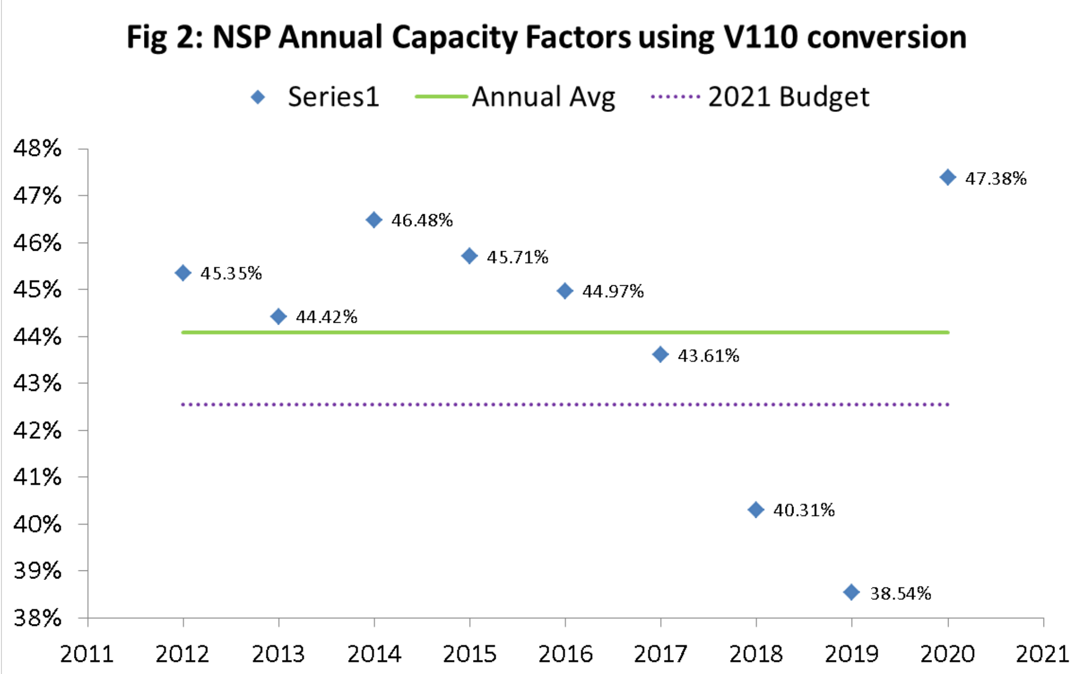


Figure 2 shows the annual capacity factors for the years 2012 through 2020 using wind speed data converted to generation using an empirical power conversion from a farm equipped with Vestas V-110 turbines. As can be seen in Figure 2, the TWY profile has an annual capacity factor that is 1.53% lower than the average of the annual capacity factors for the years 2012-2020.



Constructing Generation profiles for the TMY

As mentioned earlier, actual generation data is generally used for the TMY profile rather than generation profiles based upon wind speed data and turbine power curves. Smaller, older wind farms occasionally have outages which can last for months at a time. For currently active small wind farms with historic monthly periods of zero generation, a generation profile is created from a wind farm of similar size and geographic location with good generation data which is scaled to match the capacity of the wind farm with zero generation.[4]

Only for time periods without generation data, wind farm generation profiles were derived using wind speed data from a wind farm which is geographically proximate, then converted to generation using the most representative power conversion. In order to account for geographic diversity, the wind speed profiles may have been shifted either earlier or later.

[4] A notable exception is the 11.55 MW MinWind (Rock County) facility. Starting in October 2019 this facility stopped generating energy and is not expected to generate energy between now and the termination of the PPA in 2025. Accordingly, the generation profile for this wind farm is 0 MW for each hour of the year.

- The 200 MW Crowned Ridge 1 profile was derived using MinnDakota wind speed data with a -2 hour offset and the Crowned Ridge 1 wind farm empirical power curve.
- The 200 MW Crowned Ridge 2 profile was derived using MinnDakota wind speed data with a -1 hour offset and the Crowned Ridge 1 wind farm empirical power curve.
- The 296.2 MW Dakota Range self-build profile was derived using MinnDakota wind speed data with a 0 hour offset and the Vestas V136-4.2 turbine power curve with the top generation capped at 96%.
- The 150 MW Dakota Range 3 PPA profile was derived using MinnDakota wind speed data with a +1 hour offset and the Nordex N149-4.8 turbine power curve with the top generation capped at 96.5%.
- The 200 MW Freeborn self-build profile was derived using Pleasant Valley wind speed data with a -2 hour offset and the Vestas V136-4.2 turbine power curve with the top generation capped at 96%.
- The 200 MW Blazing Star 1 self-build profile was derived using MinnDakota wind speed data with a -2 hour offset and the Blazing Star 1 wind farm empirical power curve.
- The 200 MW Blazing Star 2 self-build profile was derived using MinnDakota wind speed data with a -1 hour offset and the Blazing Star 1 wind farm empirical power curve.
- The 150 MW Foxtail self-build profile was derived using Courtenay wind speed data with a +2 hour offset and the Foxtail wind farm empirical power curve.
- The 105.6 MW Glen Ullin PPA profile was derived using Border wind speed data with a +2 hour offset and the Glen Ullin wind farm empirical power curve.
- The 100.2 MW Lake Benton repower profile was derived using MinnDakota wind speed data with a 0 hour offset and the Lake Benton wind farm empirical power curve.
    - The Lake Benton repower affects turbines on two commercial pricing nodes: (1) Buffalo Ridge DIR TR1; and (2) Chanarambie DIR TR4. The total output of the Lake Benton repower was split on a pro-rata basis based on the capacity assigned to these two nodes.
- The 44 MW Jeffers repower profile was derived using Jeffers or Odell wind speed data with a 0 hour offset and the Jeffers wind farm empirical power curve.

- The 98.9 MW Mower County repower profile was derived using Mower County or Grand Meadows wind speed data with a 0 hour offset and the Mower County wind farm empirical power curve.
- The 100 MW Deuel Harvest profile was derived using MinnDakota wind speed data with a -1 hour offset and the Glen Ullin wind farm empirical power curve.
- The 200 MW Heartland Divide 2 profile was derived using Nobles wind speed data with a +2 hour offset and the Glen Ullin wind farm empirical power curve.
- The 26 MW Community Wind North repower profile was derived using Community Wind North or MinnDakota wind speed data with a 0 hour offset and the Community Wind North wind farm empirical power curve.
- The 80 MW Elk Creek Solar and 100 MW ND generic solar profiles were derived using irradiance data from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) and converted to generation profiles using the NREL System Advisory Model (SAM).

In December 2020, the Minnesota Commission also approved the Company's proposal to help the state recover from the economic hardship caused by the pandemic by authorizing a $750 million plan to repower five older wind farms with the latest technology. While not yet approved, the Company is also working on a repower plan for a sixth farm. Separate TMY generation profiles were created for these farms for use in future years when these repower projects are complete.

- The 200 MW Nobles repower profile was derived using Nobles wind speed data and the Glen Ullin wind farm empirical power curve.
- The 100.5 MW Grand Meadows repower profile was derived using Grand Meadows wind speed data and the Glen Ullin wind farm empirical power curve.
- The 200 MW Pleasant Valley repower profile was derived using Pleasant Valley wind speed data and the Blazing Star 1 wind farm empirical power curve.
- The 150 MW Border repower profile was derived using Border wind speed data and the Blazing Star 1 wind farm empirical power curve.
- The 100.24 MW ACE repower profile was derived using MinnDakota wind speed data and the Glen Ullin wind farm empirical power curve.
- The 21 MW Ewington repower profile was derived using Nobles wind speed data and the Glen Ullin wind farm empirical power curve.

The monthly capacity factors were reviewed for each wind farm to ensure that the monthly capacity factors were in line with the capacity factors for geographically proximate wind farms with similar vintage of turbine technology.

Because generation data from non-contiguous months were being combined, there were some extreme changes in generation volumes from the last hour of one month to the first hour of the adjoining month. Using the raw values, the four most extreme hourly changes in wind generation occurred at the transition between months. In order to eliminate these four artificially extreme ramps, the data over a 4-hour period was smoothed with a straight-line interpolation between the penultimate hour of the preceding month and the second hour of the following month.

Wind Maintenance Adjustment

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**

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Protected Data is Shaded

	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	
Barron County	10/17/2012	10/17/2012	12/31/2022	10	Barron County Waste-to-Energy Facility	All	1.865			RDF		Must Take		None
CC Calpine	3/11/2004	1/1/2006	12/31/2026	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	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
Green Whey Dairy	1/11/2012	2/16/2012	2/16/2022	10	Green Whey Dairy	All	3.2			Digester		Must Take		RPS
Gundersen Lutheran Landfill	1/11/2012	2/16/2012	2/16/2022	10	Gundersen Lutheran	All	1.137			Landfill		Must Take		RPS
Hastings	9/10/1985	10/1/1987	6/30/2033	45	City of Hastings Hydro	All	0.450			Hydro		Must Take		None
Heller DairyFarm	4/22/2013	5/1/2013	5/1/2023	10	Cow Poo LLC	All	2.7			RDF		Must Take		RPS
HERC	8/1/1986	1/1/1990	12/30/2024	28	Hennepin Energy Resource Recovery (HERC)	All	33.7			Digester		Must Take		None
Neshonoc	6/23/1986	1/1/1987	Evergreen	33	Neshkoro Power Associates - Neshonoc	All	0.400			Hydro		Must Take		RPS
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	4	Manitoba Hydro Electric Board	6am-10pm, Mon-Fri	125			Hydro		Must Take		None
Rapidan	2/24/1983	5/1/1984	1/20/2025	33	Rapidan Hydro, LLC	All	2.900			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	5/27/2010	5/26/2030	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	3/9/2017	9/11/2018	9/10/2033	15	Dragonfly Solar, LLC	All	0.8			Solar		Must Take		RPS
Solar Elk Creek Bridge	3/26/2021	1/1/2022	5/31/2023	1.5	Elk Creek Solar, LLC	All	80			Solar		Must Take		Renewable*Connect
Solar Marshall	3/4/2015	1/09/2017	6/8/2042	25.5	Marshall Solar, LLC	All	62.25			Solar		Must Take		RPS
Solar North Star	3/6/2015	12/21/2016	12/20/2041	25.67	North Star Solar PV	All	100			Solar		Must Take		RPS
Solar Slayton	11/3/2010	1/14/2013	1/3/2033	10	Slayton Solar, LLC	All	1.66			Solar		Must Take		RPS
St Cloud	5/12/1986	11/1/1988	5/31/2041	33	The City of St. Cloud	All	Summer: 8.1, Winter: 6.6 (Summer = May thru October)			Hydro		Must Take		None
StPaul CoGen	12/23/1998	3/25/2003	3/24/2023	20	St. Paul Cogeneration	All	25			Biomass		Must Take		RPS
Western Technical College Angelo Dam	4/28/2014	4/28/2014	3/31/2024	10	Western Technical College	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			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	9/28/2006	5/28/2008	5/27/2028	20	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
									PROTECTED DATA ENDS]				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	
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
Wind Garwin McNeilus	Various	Various	Various	20-25	Bangladesh Children's Support LLC, Brandon Wind LLC, BT Windfarm LLC, Burmese Children's Support, LLC, GarMar Foundation I, LLC/ REAP I, Gar Mar Wind I, LLC, GM Windfarm LLC, Henslin Creek LLC, Indian Children's Support, LLC, McNeilus Windfarm LLC, Salvadoran Children's Support , SG (JCKD) Windfarm LLC, Southeast Asian Children's Support, LLC, Triton Wind LLC, Wasioja Wind LLC, Wilhelm Wind LLC	All	27.5			Wind		Must Take		RPS
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 Minn Dakota	12/29/2005	12/31/2007	12/30/2022	15	MinnDakota Wind LLC	All	150			Wind		Must Take		RPS
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	105.75			Wind		Must Take		RPS
Wind Phase 4	4/26/2002	12/15/2003	12/14/2023	20	Chanarambie Power Partners, LLC	All	85.5			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 MinWind	10/17/2003	2/2/2005	2/1/2025	20	Minwind III -IX, LLC	All	11.55			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
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	10/26/2031		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 Viking	12/21/2002	12/18/2003	12/17/2018	15	Buffalo Ridge Wind Farm LLC, Moulton Heights Wind Power Project LLC, Muncie Power Partners LLC, North Ridge Wind Farm LLC, Vandy South Project, Viking Wind Farm LLC, Vindy Power Partners LLC, Wilson-West Windfarm LLC	All	12			Wind		Must Take		None
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
									PROTECTED DATA ENDS]				PROTECTED DATA ENDS]	

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Protected Data is Shaded

	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 Woodstock	9/19/1997	5/1/2004	4/30/2034	30	Woodstock Wind Farm, LLC	All	10.2			Wind		Must Take		RPS
Wind Crown Ridge	3/7/2017	Est. 12/31/2019	25 Yrs from COD	25	Crowned Ridge Wind, LLC	All	300			Wind		Must Take		RPS
Wind Clean Energy	3/13/2017	Est. 12/31/2019	20 Yrs from COD	20	ALLETE Clean Energy, Inc.	All	105.6			Wind		Must Take		RPS
Wind Dakota Range III		Est. 12/31/2020	20 Yrs from COD	20	DAKOTA RANGE III, LLC	All	151.2			Wind		Must Take		RPS
Wind Deuel Harvest PPA	11/25/2019	Est. 12/31/2021	20 Yrs from COD	20	Deuel Harvest Wind Energy, LLC	All	100			Wind		Must Take		Renewable*Connect
Wind Heartland Divide 2 PPA	7/21/2020	Est. 12/31/2021	20 Yrs from COD	20	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

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
1	Le Sueur	9/9/2015	0.036	5
2	Lincoln	4/25/2016	0.204	18
3	Ramsey	5/12/2016	0.125	7
4	Hennepin	8/22/2016	0.036	18
5	Chisago	12/14/2016	1	26
6	Dakota	12/14/2016	1	33
7	Chisago	12/15/2016	1	26
8	Carver	12/15/2016	1	675
9	Scott	12/19/2016	1	80
10	Dakota	12/20/2016	1	14
11	Stearns	12/21/2016	1	35
12	Dakota	12/22/2016	1	13
13	Stearns	1/4/2017	1	12
14	Stearns	1/5/2017	1	293
15	Goodhue	1/12/2017	0.972	28
16	Dakota	1/13/2017	1	13
17	Chisago	1/13/2017	0.972	16
18	Goodhue	2/13/2017	1	300
19	Carver	2/28/2017	0.972	13
20	Washington	3/10/2017	0.036	7
21	Wabasha	3/13/2017	1	189
22	Dakota	3/15/2017	1	204
23	Blue Earth	5/31/2017	1	12
24	Redwood	5/31/2017	1	41
25	Winona	5/31/2017	0.25	31
26	Rice	6/30/2017	1	282
27	Dodge	7/18/2017	1	494
28	Washington	7/18/2017	1	202
29	Olmsted	7/19/2017	1	437
30	Kandiyohi	8/14/2017	1	7
31	Pipestone	8/18/2017	1	46
32	Chisago	8/22/2017	1	11
33	Stearns	8/24/2017	1	20
34	Chippewa	8/29/2017	1	10
35	Dakota	8/31/2017	1	26
36	Pope	9/13/2017	1	19
37	Stearns	9/13/2017	0.972	17
38	Stearns	9/13/2017	0.972	24
39	Lincoln	9/14/2017	0.2	21
40	Sherburne	9/22/2017	1	153
41	Dodge	9/27/2017	1	21
42	Benton	9/29/2017	1	22
43	McLeod	10/25/2017	1	38

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
44	Chippewa	10/25/2017	1	50
45	Hennepin	10/25/2017	1	12
46	McLeod	10/26/2017	1	100
47	Pipestone	10/30/2017	1	40
48	Stearns	10/30/2017	1	24
49	Benton	10/30/2017	1	23
50	Wright	11/3/2017	1	1192
51	Stearns	11/9/2017	1	14
52	Wright	11/13/2017	1	1169
53	Stearns	11/16/2017	1	122
54	Nicollet	11/20/2017	1	13
55	Blue Earth	11/20/2017	1	35
56	Scott	11/30/2017	0.998	13
57	Scott	11/30/2017	0.7	7
58	Dakota	11/30/2017	1	135
59	Rice	11/30/2017	1	210
60	Stearns	12/13/2017	1	14
61	Chisago	12/13/2017	1	11
62	Carver	12/15/2017	1	34
63	Chisago	12/18/2017	1	10
64	Dodge	12/18/2017	1	34
65	Scott	12/20/2017	0.997	12
66	Carver	12/21/2017	0.396	14
67	Renville	12/28/2017	1	47
68	Washington	1/10/2018	1	21
69	Carver	1/16/2018	1	11
70	Le Sueur	1/18/2018	1	12
71	Dakota	1/23/2018	0.99	14
72	Wabasha	1/29/2018	1	12
73	Pipestone	1/31/2018	1	44
74	Sherburne	2/12/2018	0.25	177
75	Rice	2/14/2018	0.998	163
76	Le Sueur	2/23/2018	1	33
77	Carver	2/26/2018	0.998	311
78	Waseca	2/26/2018	1	29
79	Rice	2/28/2018	1	11
80	Le Sueur	2/28/2018	1	39
81	Washington	2/28/2018	1	702
82	Faribault	3/2/2018	1	14
83	Rice	3/2/2018	1	10
84	Steele	3/5/2018	0.4	83
85	Carver	3/6/2018	1	12
86	Chisago	3/13/2018	1	12

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
87	Carver	3/14/2018	0.998	143
88	Sherburne	3/14/2018	1	22
89	Pope	3/15/2018	1	497
90	Benton	3/25/2018	1	12
91	Scott	3/28/2018	0.99	19
92	Goodhue	4/12/2018	0.8	139
93	Washington	4/13/2018	1	16
94	Pope	4/19/2018	1	280
95	Washington	4/20/2018	1	12
96	Goodhue	4/26/2018	0.998	132
97	Chisago	4/30/2018	1	9
98	Stearns	4/30/2018	1	30
99	Sherburne	4/30/2018	1	29
100	Goodhue	5/11/2018	1	27
101	Renville	5/16/2018	1	24
102	Renville	5/17/2018	1	21
103	Goodhue	5/22/2018	1	10
104	Blue Earth	5/30/2018	1	10
105	Steele	6/5/2018	1	7
106	Hennepin	6/6/2018	0.18	32
107	Chippewa	6/15/2018	1	28
108	Lyon	6/15/2018	1	37
109	Rice	6/20/2018	1	19
110	Le Sueur	6/29/2018	1	12
111	Sherburne	6/29/2018	1	14
112	Watonwan	7/2/2018	0.25	23
113	Sherburne	7/13/2018	1	15
114	Washington	7/16/2018	1	10
115	Steele	7/18/2018	1	7
116	Goodhue	7/19/2018	1	18
117	Dakota	7/27/2018	1	23
118	Goodhue	7/30/2018	1	16
119	Chisago	8/1/2018	1	26
120	DOUGLAS	8/2/2018	1	304
121	Le Sueur	8/6/2018	1	467
122	Blue Earth	8/7/2018	1	535
123	Chisago	8/9/2018	1	16
124	Wright	8/14/2018	0.972	6
125	Benton	8/14/2018	0.99	13
126	Carver	8/16/2018	0.25	338
127	Wright	8/27/2018	1	442
128	Chisago	8/30/2018	1	11
129	Washington	9/4/2018	0.25	444

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
130	Washington	9/7/2018	0.25	96
131	Goodhue	9/14/2018	1	12
132	Dakota	9/17/2018	0.75	9
133	Goodhue	9/19/2018	1	24
134	Waseca	9/27/2018	1	6
135	Chisago	9/28/2018	1	50
136	Chisago	9/28/2018	1	8
137	Hennepin	9/28/2018	0.32	32
138	Blue Earth	10/16/2018	1	22
139	Wright	10/17/2018	1	24
140	McLeod	10/25/2018	1	6
141	Waseca	10/25/2018	1	6
142	Washington	10/29/2018	1	14
143	Benton	10/30/2018	1	11
144	Waseca	11/1/2018	1	11
145	Chippewa	11/14/2018	1	143
146	Kandiyohi	11/14/2018	1	27
147	Pope	11/16/2018	1	18
148	Sherburne	11/16/2018	1	6
149	Chisago	11/26/2018	1	12
150	Chisago	11/27/2018	1	16
151	Wright	11/28/2018	1	12
152	Scott	11/28/2018	0.823	9
153	Hennepin	11/28/2018	0.527	72
154	Scott	11/28/2018	1	9
155	Chisago	11/28/2018	1	10
156	Chisago	11/28/2018	1	12
157	Chisago	11/29/2018	1	14
158	Sherburne	12/3/2018	1	16
159	Chisago	12/7/2018	1	8
160	Sherburne	12/10/2018	1	15
161	Chisago	12/11/2018	0.5	19
162	Stearns	12/17/2018	1	64
163	Benton	12/17/2018	1	10
164	Benton	12/17/2018	1	8
165	Chippewa	12/18/2018	1	14
166	Le Sueur	12/19/2018	1	12
167	Murray	12/20/2018	1	9
168	Murray	12/20/2018	1	12
169	Yellow Medicine	12/21/2018	1	83
170	Ramsey	1/8/2019	0.54	8
171	Dodge	1/9/2019	1	12
172	Hennepin	1/11/2019	1	697

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
173	Meeker	1/23/2019	0.76	10
174	Stearns	1/28/2019	0.324	9
175	Nicollet	1/31/2019	1	8
176	Waseca	2/13/2019	1	12
177	Chisago	2/27/2019	1	11
178	Stearns	3/4/2019	0.72	10
179	Stearns	3/4/2019	1	13
180	Blue Earth	3/5/2019	0.24	8
181	McLeod	3/12/2019	1	32
182	Washington	3/22/2019	1	127
183	Stearns	3/25/2019	1	11
184	Wabasha	3/26/2019	0.85	133
185	Pope	3/26/2019	1	18
186	Sherburne	3/28/2019	1	24
187	Pope	3/28/2019	1	17
188	Renville	3/29/2019	1	16
189	Goodhue	4/11/2019	1	543
190	Stearns	4/16/2019	1	12
191	Chisago	4/22/2019	1	219
192	Washington	4/22/2019	1	110
193	Wright	4/29/2019	1	1070
194	Rice	4/30/2019	1	8
195	Carver	5/1/2019	1	7
196	Lyon	5/3/2019	1	13
197	Benton	5/13/2019	1	287
198	Dodge	5/15/2019	1	78
199	Dodge	5/15/2019	0.4	81
200	Kandiyohi	5/21/2019	1	10
201	Chisago	5/21/2019	1	9
202	Wright	5/31/2019	1	150
203	Stearns	6/3/2019	1	14
204	Dakota	6/7/2019	1	16
205	Dakota	6/7/2019	1	12
206	Sibley	6/14/2019	1	58
207	Stearns	6/18/2019	1	16
208	Freeborn	6/18/2019	0.25	39
209	Chisago	7/3/2019	1	15
210	Carver	7/22/2019	1	10
211	Scott	7/24/2019	0.598	64
212	Carver	7/25/2019	1	9
213	Sherburne	7/26/2019	1	17
214	Hennepin	7/30/2019	0.18	21
215	Sherburne	7/31/2019	0.996	148

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
216	Dakota	8/6/2019	1	143
217	Rice	8/8/2019	1	50
218	Scott	8/13/2019	1	13
219	Chisago	8/16/2019	0.998	210
220	Stearns	8/16/2019	1	166
221	Stearns	8/16/2019	1	155
222	Wabasha	8/20/2019	1	154
223	Wabasha	8/20/2019	1	140
224	Winona	8/21/2019	1	197
225	Winona	8/22/2019	1	129
226	Wabasha	8/22/2019	1	117
227	Winona	8/22/2019	1	90
228	Chippewa	8/26/2019	1	23
229	Carver	8/29/2019	1	7
230	McLeod	8/30/2019	1	13
231	Chisago	9/3/2019	1	7
232	Waseca	9/6/2019	1	11
233	Olmsted	9/9/2019	1	7
234	Pope	9/11/2019	1	12
235	Pope	9/11/2019	1	10
236	Hennepin	9/18/2019	0.96	191
237	Rice	9/18/2019	1	14
238	Blue Earth	9/24/2019	0.62	34
239	Goodhue	9/27/2019	1	32
240	Blue Earth	9/27/2019	0.62	28
241	Rice	10/9/2019	1	17
242	Stearns	10/23/2019	1	26
243	Stearns	10/25/2019	0.95	41
244	Sherburne	10/29/2019	1	15
245	Scott	10/30/2019	0.4	6
246	Waseca	11/18/2019	0.996	150
247	Sherburne	11/26/2019	1	15
248	Stearns	12/3/2019	1	13
249	Meeker	12/11/2019	1	42
250	Dakota	12/11/2019	1	16
251	DOUGLAS	12/11/2019	1	26
252	Meeker	12/13/2019	1	202
253	Rice	12/13/2019	1	10
254	Pope	12/16/2019	1	7
255	Stearns	12/16/2019	1	10
256	Nicollet	12/18/2019	1	189
257	Blue Earth	12/18/2019	1	168
258	McLeod	12/18/2019	1	158

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
259	Chisago	12/19/2019	1	11
260	Stearns	12/23/2019	1	16
261	Sherburne	12/23/2019	1	15
262	Sherburne	12/26/2019	1	10
263	Stearns	12/27/2019	1	196
264	DOUGLAS	12/27/2019	1	156
265	McLeod	12/27/2019	1	10
266	Renville	12/30/2019	1	14
267	Sherburne	12/30/2019	0.94	8
268	Goodhue	12/31/2019	0.59	6
269	Winona	1/3/2020	1	195
270	Winona	1/3/2020	1	200
271	Stearns	1/13/2020	1	17
272	Rice	1/14/2020	1	10
273	Dakota	1/15/2020	1	8
274	Meeker	1/17/2020	1	7
275	Winona	2/12/2020	1	22
276	Goodhue	2/13/2020	1	27
277	Pope	2/17/2020	1	12
278	Hennepin	2/17/2020	0.29	7
279	Rice	2/20/2020	1	12
280	Goodhue	2/26/2020	1	20
281	Pope	2/26/2020	1	14
282	Waseca	2/27/2020	1	9
283	Goodhue	2/28/2020	1	217
284	Goodhue	2/28/2020	1	197
285	Sherburne	2/28/2020	1	21
286	Waseca	3/4/2020	1	10
287	Washington	3/9/2020	1	8
288	Goodhue	3/9/2020	1	215
289	Rice	3/20/2020	1	11
290	Sibley	3/26/2020	1	16
291	Dakota	3/26/2020	1	11
292	Sibley	4/3/2020	1	19
293	Olmsted	4/3/2020	1	9
294	Dodge	4/7/2020	1	13
295	DOUGLAS	4/9/2020	1	18
296	Olmsted	4/13/2020	1	12
297	Olmsted	4/16/2020	1	0
298	Rice	4/24/2020	0.96	104
299	Scott	4/27/2020	1	793
300	Rice	4/27/2020	1	16
301	Goodhue	4/30/2020	1	28

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
302	Chisago	5/19/2020	1	10
303	Benton	5/20/2020	1	10
304	Stearns	5/21/2020	1	6
305	Dodge	5/21/2020	1	12
306	Carver	5/28/2020	1	52
307	Pope	5/30/2020	1	28
308	Dakota	6/2/2020	1	233
309	Dakota	6/4/2020	1	239
310	Waseca	6/16/2020	1	9
311	Rice	6/17/2020	1	22
312	Winona	6/24/2020	1	17
313	Winona	6/24/2020	1	40
314	Benton	7/10/2020	1	21
315	Rice	7/13/2020	1	30
316	Rice	7/20/2020	1	31
317	McLeod	7/20/2020	1	12
318	Nicollet	7/30/2020	1	13
319	Goodhue	7/30/2020	1	17
320	Stearns	7/31/2020	1	16
321	Wright	7/31/2020	1	25
322	Le Sueur	7/31/2020	1	9
323	Sherburne	7/31/2020	1	27
324	Goodhue	8/18/2020	1	11
325	Sherburne	9/1/2020	1	11
326	Redwood	9/14/2020	0.86	31
327	Chisago	9/14/2020	1	10
328	Waseca	9/15/2020	1	14
329	Chippewa	9/16/2020	1	23
330	Redwood	9/16/2020	1	32
331	Waseca	9/21/2020	1	12
332	Steele	9/22/2020	1	9
333	Nicollet	9/22/2020	1	7
334	Redwood	9/28/2020	1	25
335	Washington	9/28/2020	1	21
336	Freeborn	9/29/2020	1	25
337	Wright	10/1/2020	1	9
338	Dodge	10/6/2020	1	14
339	Dakota	10/6/2020	1	7
340	Clay	10/8/2020	1	42
341	Clay	10/8/2020	1	38
342	Clay	10/8/2020	1	37
343	Clay	10/8/2020	1	32
344	Nicollet	10/8/2020	1	27

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
345	Benton	10/14/2020	1	9
346	Rice	10/15/2020	0.7	8
347	Kandiyohi	10/19/2020	1	15
348	Kandiyohi	10/19/2020	1	13
349	Washington	10/20/2020	1	86
350	Clay	10/21/2020	1	31
351	Goodhue	10/26/2020	1	9
352	Waseca	10/27/2020	1	10
353	Renville	10/29/2020	1	15
354	Freeborn	10/30/2020	1	55
355	Chippewa	10/30/2020	1	26
356	Benton	11/3/2020	1	100
357	Dakota	11/4/2020	1	11
358	Goodhue	11/5/2020	1	20
359	Olmsted	11/9/2020	1	10
360	Dodge	11/9/2020	1	18
361	Sherburne	11/10/2020	1	11
362	Dodge	11/16/2020	1	9
363	Goodhue	11/19/2020	1	9
364	Rice	11/19/2020	1	11
365	Dodge	11/23/2020	1	11
366	Winona	11/30/2020	1	22
367	Stearns	12/1/2020	1	0
368	Renville	12/4/2020	1	0
369	McLeod	12/4/2020	1	0
370	Lyon	12/7/2020	1	0
371	Chisago	12/9/2020	1	0
372	Stearns	12/9/2020	1	0
373	Carver	12/10/2020	1	0
374	Chisago	12/11/2020	1	0
375	Pope	12/14/2020	1	0
376	Pope	12/14/2020	1	0
377	Stearns	12/16/2020	1	0
378	Nicollet	12/17/2020	1	0
379	Rice	12/21/2020	1	0
380	Pope	12/21/2020	1	0
381	Pope	12/28/2020	1	0
382	McLeod	12/30/2020	1	0

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 2021v1.0 Forecast (completed in March 2021).

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;
    - 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, including the following:
    - Number of Small Commercial and Industrial customers;
    - Gross State/Metro Product for the respective jurisdiction;
    - Employment for the respective jurisdiction;

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

- 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, including the following:
    - 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, including the following:
    - 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, including the following:
    - 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 this model, we use the time period from 2003 to December 2020 and therefore the historical DSM would include any measure that results in decreased sales in any (or all) years from 2003 through December 2020. 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 2003 through December 2020 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 Regulatory Strategy and Planning 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 2020 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 levels for several large customers. In addition, the historical Large Commercial and Industrial sales data was adjusted to remove sales from two large customers who have ceased operations in order to create a consistent data series.

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 limited interval trend variable to account for the declining COVID-19 pandemic impacts. Conversely, the Small Commercial and Industrial and Large Commercial and Industrial customer classes have 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 Commercial and Industrial regression models. 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 workable 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 2001-2020. 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 a historical average loss factor for each jurisdiction and assumes it will not change in the future.

Former AAA	Description	Docket or Rule	May 1, 2021 Annual Forecast of Rates
Part D, Section 1 and all Schedules	Policies and Actions: Fuel Procurement	Rule 7825.2800	Part D, Attachment 1
D-1, Schedule 1	Nuclear Fuel Component of Service	Rule 7825.2800	Part D, Attachment 2
D-1, Schedule 2	Coal Contracts	Rule 7825.2800	Part D, Attachment 3
D-1, Schedule 3	Transportation & Related Services Contracts	Rule 7825.2800	Part D, Attachment 4
D-1, Schedule 4	Wood and RDF Contracts	Rule 7825.2800	Part D, Attachment 5
D-1, Schedule 5	Cost Changes	Rule 7825.2800	Part D, Attachment 6
Part D, Section 2	Policies and Actions: Dispatching Policies and Procedures	Rule 7825.2800	Part D, Attachment 7
Part D, Section 3	Policies and Actions: Fuel Supply	Rule 7825.2800	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, Section 5	Policies and Actions: Other Actions to Minimize Costs	Rule 7825.2800	Part D, Attachment 10
Part E, Section 1	Annual Report of Automatic Adjustment Charges: Base Cost of Fuel	Rule 7825.2810; Docket 04-1279	Discussed in Petition, Section IX, Subsection B Part A, Attachment 1
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, Section IX, Subsection B
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, Section IX, Subsection B
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, Section IX, Subsection B
Part E, Section 5	Annual Report of Automatic Adjustment Charges: Monthly Fuel Clause Adjustment	Rule 7825.2810; Docket 04-1279	Discussed in Petition, Section IX, Subsection B Part A, Attachment 1
Part F, Schedule 1	Memo Engaging Auditor	Rule 7825.2820	NA
Part F, Schedule 2	Independent Auditor’s Report	Rule 7825.2820	NA
Part G, Schedule 1	5-Year Fuel Cost Forecast – Per Unit Summary	Rule 7825.2830	Part A, Attachment 1 Part E, Attachment 3
Part G, Schedule 2	5-Year Fuel Cost Forecast – Cost Summary	Rule 7825.2830	Part A, Attachment 2 Part E, Attachment 1
Part G, Schedule 3	5-Year Fuel Cost Forecast – Energy Summary	Rule 7825.2830	Part A, Attachment 3 Part E, Attachment 2
Part G, Schedule 4	Fossil Fuel Costs	Rule 7825.2830	Part B, Attachment 2 Part E, Attachment 4
Part G, Schedule 5	Coal Burn Expenses	Rule 7825.2830	Part B, Attachment 3 Part E, Attachment 5
Part G, Schedule 6	Nuclear Fuel Expenses	Rule 7825.2830	Part B, Attachment 4 Part E, Attachment 6
Part G, Schedule 7	Peak Demand and Energy Requirements	Rule 7825.2830	Part A, Attachment 4 Part E, Attachment 7
Part G, Schedule 8	Estimated Load Management Impact	Rule 7825.2830	Part E, Attachment 8
Part H, Section 3	Natural Gas Financial Instruments	Dockets M-01-1953 and AA-02-950	NA
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 H, Section 5, Schedule 2	Wind Curtailment Report Narrative	Docket AA-04-1279	Discussed in Petition, Section VI, Subsection A - x and xiii Part G, Workpaper 9
Part H, Section 6	KODA PPA	Docket M-08-1098	NA
Part H, Section 7	WMRE PPA	Docket M-10-61	NA
Part H, Section 8	Diamond K Dairy PPA	Docket M-486	NA

Former AAA	Description	Docket or Rule	May 1, 2021 Annual Forecast of Rates
Part H, Section 9 and Schedules H-9-1 and H-9-2	Community Solar Gardens	Docket M-13-867	Discussed in Petition, Section VI, Subsection A - ix Part B, Attachment 12 Part G, Workpapers 7 & 8
Part H, Section 10	FCA Rule Variance Dockets	Docket AA-15-611	Discussed in Petition, Section VIII, Subpart B Part C, Attachment 2
Part H, Section 11	HERC	Docket 17-532	NA
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
Part J, Section 5	Monthly MISO Day 2 charges and allocation	Docket AA-07-1130	Discussed in Petition, Section VI, Subsection A - xiii Part B, Attachment 9 Part F, Workpaper 5
Part J, Section 6	Annual and Daily Ancillary Services Market charges and summary	Docket M-08-528	NA
Part K, Section 1	Generation facilities maintenance expenses	Docket AA-06-1208	NA
Part K, Section 3	Contractor and supplier performance	Docket AA-08-995	NA
Part K, Section 4 Schedule 1	Offsetting Revenues and/or compensation Received by IOUs	Docket AA-10-884	NA
Part K, Section 4 Schedule 2	Handling of forced outages	Docket 08-995 and Docket AA-10-884	NA
Part K, Section 4 Schedule 3	Unusual Adjustments over $500,000	Dockets AA-09-961 and AA-10-884	NA
New Compliance	Self-Scheduling	Dockets AA-17-492 and CI-19-704	NA
Part M	Notice of Reports Availability	Rule 7825.2840	Addendum to Petition
New Compliance	Renewable*Connect Neutrality	Docket M-15-985	NA
New Compliance	MISO Day 2 and Day 3 charges	Docket 19-293	Part A, Attachments 1-3

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 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
- Forecast FCA – E002/M-00-420, E002/M-01-477, E,G002/M-01-838, E002/M-02-645, E002/M-03-585, E002/M-04-595, E002/M-05-613, E002/M-06-589, E002/M-07-484, E002/M-08-451, E002/M-14-364, and E002/M-17-445
- Fuel Clause Reform – E999/CI-03-802, Orders dated December 19, 2017, June 12, 2019, and November 5, 2019
- 2019 Fuel Factor True-Up – E002/AA-20-182
- 2020 Fuel Forecast and Factors – E002/AA-19-293
- Adjustment to 2020 Fuel Factors – E002/AA-20-437
- 2021 Fuel Forecast and Factors – E002/AA-20-417

The fuel clause adjustment factors also reflect the MISO Day 2 and ASM charges recovery, wind contracts curtailment payments, renewable energy purchase agreements, the Renewable*Connect 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, E002/M-09-1055, Notice of Approval dated October 12, 2009. 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
- Goodhue North, LLC, E002/M-09-1349, Order dated April 28, 2010[1]
- Goodhue South, LLC, E002/M-09-1350, Order dated April 28, 2010[2]
- 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, E002/M-09-1481, Order dated June 25, 2010[3]
- WM Renewable Energy, LLC, E002/M-10-161, Order dated April 30, 2010
- Big Blue, LLC, E002/M-10-733, Notice of Approval dated August 26, 2010[4]
- Community Wind North, LLC, E002/M-10-734, Order dated August 26, 2010[5]
- 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, E002/M-08-1487, Order dated April 24, 2009. Amendment approved in E002/M-19-58, Order dated March 25, 2019[6]
- Ewington Energy Systems LLC, E002/M-06-1472, Notice of Approval dated November 30, 2006 and E002/M-20-620, Order dated January 22, 2021
- Jeffers Wind 20, LLC, E002/M-06-1234, Notice of Approval dated November 30, 2006[7]
- Uilk Wind Farm, LLC, E002/M-08-1502, Notice of Approval dated February 6, 2009

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[1] On July 24, 2013, the Company notified the MPUC that the PPAs with Goodhue North and Goodhue South had been terminated. The MPUC issued an Order closing the associated dockets on October 23, 2013.
[2] Id.
[3] The amended PPA was approved by the Commission's September 8, 2014 Order in Docket No. E002/M-14-490.
[4] The amended PPA was approved by the Commission's February 27, 2014 Order in Docket No. E002/M-13-1002.
[5] The Commission approved the Company's acquisition of this project in its December 3, 2019 Order in Docket No. E002/PA-18-777. The PPA was terminated on December 31, 2020, and this facility is now owned by the Company.
[6] 100% of this resource is currently reserved for the Windsource program, and so no costs associated with the PPA flow through the fuel clause.
[7] The Commission approved the Company's acquisition of this project in its December 3, 2019 Order in Docket No. E002/PA-18-777. The PPA was terminated on December 31, 2020, and this facility is now owned by the Company.

  - 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
  - Dakota Range III, E002/M-18-765, Order dated July 19, 2019
- Windsource Exemption – E002/M-01-1479, E002/M-09-1177 [8]
- End-Of-Life Nuclear Fuel Accrual – E002/M-05-1648
- Community Solar Gardens Program – E002/M-13-867
- Renewable*Connect – E002/M-15-985, Order dated February 27, 2017 and E002/M-19-33, Order dated August 12, 2019
- Inver Hills Sales Gain Sharing Refund – E002/PA-17-529, Order dated February 16, 2018
- Sherco Land Sale Sharing Refund – E002/M-17-528, Order dated February 6, 2018
- Solar Energy Standard Exemption – E002/M-17-425, Order dated October 12, 2017
- Sherco 3 Outage Settlement – E002/GR-12-961, E002/GR-13-868, E999/AA-13-599, E999/AA-14-579, E999/AA-16-523, E999/AA-17-482 and E999/AA-18-373, Order dated April 11, 2019

[8] The Windsource program will end on or around January 1, 2022, and subscribers will be transitioned to the Renewable*Connect program.

FUEL PROCUREMENT POLICIES

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.

In 2020, we began to offer the King Station and Unit 2 of the Sherburne County Generating Station into the MISO market on a seasonal basis. Although we expect this change in approach to dispatching these units will have an impact on our total coal requirements for these units, we do not expect it to change our general coal purchasing strategy to meet the lower requirements.

Nuclear

The market price for uranium during the early part of first quarter of 2021 has been trending lower with a high spot market price of $30.40 per pound in early January to a low of $29.10 per pound in early February.

Even at today's market prices, the cost of nuclear fuel continues to be higher than the historical costs of the 1990s and early 2000s, when the market price for uranium was less than $10.00 per pound. With the continued weakness in market prices, the current prices are at a level that is impacting the forecast levels of uranium production. Existing supply in the marketplace has decreased through the closure of mines, reduction of production targets, suspension of production at mines throughout the world, and buying by producers to fulfill contractual obligations. Global uranium production is forecasted to increase by 9% in 2021. Early closures of nuclear power plants in the United States have reduced demand, but uranium demand and supply are forecasted to be at similar levels in 2021 and 2022. Unpredicted differences between supply and demand is projected to be covered by end user inventories. Spot market volume at 91.7 million pounds of U_3O_8 for 2020 is significantly above the 56.3 million pounds of U_3O_8 for 2019 and is approximately 3.4 percent greater than the volume for this period in 2018 (88.7 million pounds). Volume in the later part of 2020 declined from record levels in the first part of 2020 and spot market prices also declined in the later part of 2020. For the rest of 2021 and into 2022, prices will likely decrease moderately as uranium end users draw down inventories, producers cover obligations, and anticipated U.S policy-related decisions occur. Spot market volumes are forecasted to remain low through early 2021. Longer-term prices will likely increase as production beyond 2023 is forecasted to be below demand and potential impacts that may occur based on any actions that are taken as a result of policy-related decisions. Additionally, demand is likely to increase with the restart of more reactors in Japan and as construction and start-up of new nuclear power plants world-wide continues. Prices could be further impacted if supply projections are not met. Closings of nuclear reactors world-wide have decreased demand and increased uranium end-user inventories. The current market analysis forecasts supply and inventories meeting demand until about 2024, but will continue to be dependent on the willingness of suppliers to bring new supply into the market, as well as the interest of companies and governments to continue construction of new nuclear power plants. Continued developments in government programs and agreements will favorably influence supply/demand projections and should help to moderate future increases to nuclear fuel prices.

Several trade activities, such as uncertainty with regard to trade policy with China and implementation of the new Russian Suspension Agreement beyond 2020 and continued threats of 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 2020. If quotas under the new Russian Suspension Agreement and/or 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 be significantly impacted. A list of current nuclear fuel components of service contracts is shown on Part D, Attachment 2.

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. In light of the February 2021 natural gas market price spike, the Company will be assessing the performance of this strategy.

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 20 and 25 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. Delivered wood fuel costs have seen a modest decline in price recently, primarily due to fuel switching to low-cost natural gas by many biomass fuel consumers such as wood product and paper mills. 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.

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.

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Nuclear Fuel Components of Services for the Period of January through December 2020

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
	[PROTECTED DATA BEGINS			
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4				
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12				
				PROTECTED DATA ENDS]

	[PROTECTED DATA BEGINS			
13				
14				
15				
16				
17				
				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				
				PROTECTED DATA ENDS]

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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				
5				
6				
				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				
5				
6				
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				
14				
15				
16				
17				
18				
19				
20				
21				
22				
				PROTECTED DATA ENDS]

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	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
23				
24				
25				
26				
27				
28				
				PROTECTED DATA ENDS]

Cost Changes – January 1, 2020 to January 1, 2021

	Contract	Percent Change
[PROTECTED DATA BEGINS		

PROTECTED DATA ENDS]

Cost Changes – January 1, 2020 to January 1, 2021

	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, 2020 compared to the contract price on January 1, 2021.

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 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 2020.

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

3. A contract was executed in **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**

   A contract was executed in **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**

   A contract was executed in **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**

   A contract amendment was executed in **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

A contract amendment was executed in **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**

A contract amendment was 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 $2.02/MBtu during 2019. (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 2018 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]

CONSERVATION IMPROVEMENT PROGRAM

Xcel Energy's Conservation Improvement Program (CIP) is designed to help our customers use energy wisely. The Company has developed nearly 40 commercial and residential CIP programs with the intent of providing customers the opportunity to lower their energy consumption and overall energy bills.

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 CIP. CIP 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 CIP 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.

Additionally, the Company has several electric load management programs available to customers. These programs provide customers rate discounts for reducing electric load on days with peak demand for electricity or rebates for participation in control events utilizing a smart thermostat or energy management systems.

The Company is required to file with the Department every three years, a CIP 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 CIP Triennial Plan, which was filed on July 1, 2020 and approved on November 25, 2020.[1]

On April 1 of each year, the Company is required to file with the Department an annual CIP Status Report, which details the cost-effectiveness and spending for the prior year's CIP program. The Deputy Commissioner issued approval of the Company's 2019 CIP Status Report on August 6, 2020.[2]

[1] Docket No. E,G002/CIP-20-473
[2] Docket No. E,G002/CIP-16-115.08

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)[1] are transmission-owning members of MISO. NSPM and NSPW (the NSP Companies) 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.

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2023 - Dec 2026

Protected Data Shaded

Line #	Updated 4-1-2021													
1	*Costs in $1,000's*	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	2023 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	$10,705	$15,417	$21,946	$25,524	$30,066	$26,715	$31,865	$30,703	$21,763	$17,261	$11,785	$9,523	$253,274
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**	($8,400)	($12,990)	($18,968)	($21,839)	($25,352)	($22,576)	($25,388)	($24,425)	($18,550)	($15,098)	($10,121)	($7,794)	($211,502)
31	**Less Renewable Connect Pilot**													
32	**Less Renewable Connect MTM**													
33	**Less Renewable Connect LT**													
34														
35	**Net System Costs**													
36														
37	**Net System Sales**													
38	Calendar Month MWh Sales													
39														
40	**Less Renewable Connect Pilot MWh Sales**													
41	**Less Renewable Connect MTM MWh Sales**													
42	**Less Renewable Connect LT MWh Sales**													
43														
44	**Net Sys MWh Sales**													
45														
46	**System Cost in cents/kWh**													
47														
48	**Minnesota Juris. MWh Sales**													
49														
50	**Less Renewable Connect Pilot MWh Sales**													
51	**Less Renewable Connect MTM MWh Sales**													
52	**Less Renewable Connect LT MWh Sales**													
53														
54	**Net MN MWh Sales**													
55														
56	**MN Fuel Cost**													
57	**Solar Gardens - Above Market Cost**	$8,400	$12,990	$18,968	$21,839	$25,352	$22,576	$25,388	$24,425	$18,550	$15,098	$10,121	$7,794	$211,502
58	**Laurentian Buyout costs**													
59	**Pine Bend Buyout Cost**													
60	**Benson Buyout Cost**													
61														
62	**Forecast MN FCA Costs**													
63														
64														
65	**Forecast MN FCA Cost in cents/kWh**													
66														
67														
68	**Forecast MN FCA Cost in $/MWh**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2023 - Dec 2026

Protected Data Shaded

Line #	Updated 4-1-2021													
1	*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
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	$13,109	$19,497	$26,280	$30,262	$35,320	$31,114	$36,816	$35,207	$24,781	$19,524	$13,247	$10,642	$295,798
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**	($10,354)	($16,349)	($22,208)	($25,286)	($28,883)	($25,336)	($27,841)	($26,702)	($19,934)	($16,222)	($10,785)	($8,425)	($238,325)
31	**Less Renewable Connect Pilot**													
32	**Less Renewable Connect MTM**													
33	**Less Renewable Connect LT**													
34														
35	**Net System Costs**													
36														**PROTECTED DATA ENDS]**
37	**Net System Sales**													
38	Calendar Month MWh Sales													
39														
40	**Less Renewable Connect Pilot MWh Sales**													
41	**Less Renewable Connect MTM MWh Sales**													
42	**Less Renewable Connect LT MWh Sales**													
43														
44	**Net Sys MWh Sales**													
45														
46	**System Cost in cents/kWh**													
47														
48	**Minnesota Juris. MWh Sales**													
49														
50	**Less Renewable Connect Pilot MWh Sales**													
51	**Less Renewable Connect MTM MWh Sales**													
52	**Less Renewable Connect LT MWh Sales**													
53														
54	**Net MN MWh Sales**													
55														
56	**MN Fuel Cost**													
57	**Solar Gardens - Above Market Cost**													
58	**Laurentian Buyout costs**													
59	**Pine Bend Buyout Cost**													
60	**Benson Buyout Cost**													
61														
62	**Forecast MN FCA Costs**													
63														
64														
65	**Forecast MN FCA Cost in cents/kWh**													
66														
67														
68	**Forecast MN FCA Cost in $/MWh**													

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Northern States Power Company
Electric Utility - State of Minnesota
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Updated 4-1-2021

Protected Data Shaded

Line #	*Costs in $1,000's*	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	$14,570	$20,664	$28,994	$33,268	$38,694	$33,972	$40,066	$38,194	$26,800	$21,051	$14,241	$11,408	$321,922
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**	($10,964)	($16,296)	($23,159)	($26,952)	($30,788)	($26,155)	($27,800)	($26,795)	($20,060)	($16,596)	($11,067)	($8,629)	($245,259)
31	**Less Renewable Connect Pilot**													
32	**Less Renewable Connect MTM**													
33	**Less Renewable Connect LT**													
34														
35	**Net System Costs**													
36														**PROTECTED DATA ENDS]**
37	**Net System Sales**													
38	Calendar Month MWh Sales													
39														
40	**Less Renewable Connect Pilot MWh Sales**													
41	**Less Renewable Connect MTM MWh Sales**													
42	**Less Renewable Connect LT MWh Sales**													
43														
44	**Net Sys MWh Sales**													
45														
46	**System Cost in cents/kWh**													
47														
48	**Minnesota Juris. MWh Sales**													
49														
50	**Less Renewable Connect Pilot MWh Sales**													
51	**Less Renewable Connect MTM MWh Sales**													
52	**Less Renewable Connect LT MWh Sales**													
53														
54	**Net MN MWh Sales**													
55														
56	**MN Fuel Cost**													
57	**Solar Gardens - Above Market Cost**													
58	**Laurentian Buyout costs**													
59	**Pine Bend Buyout Cost**													
60	**Benson Buyout Cost**													
61														
62	**Forecast MN FCA Costs**													
63														
64														
65	**Forecast MN FCA Cost in cents/kWh**													
66														
67														
68	**Forecast MN FCA Cost in $/MWh**													

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Northern States Power Company
Electric Utility - State of Minnesota

Jan 2023 - Dec 2026

Protected Data Shaded

Line #	Updated 4-1-2021													
1	*Costs in $1,000's*	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	$15,739	$22,228	$31,067	$35,516	$41,166	$36,025	$42,356	$40,258	$28,171	$22,069	$14,893	$11,901	$341,388
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**	($11,384)	($16,736)	($23,844)	($28,586)	($32,064)	($26,162)	($28,086)	($26,996)	($20,618)	($17,179)	($11,579)	($8,916)	($252,150)
31	**Less Renewable Connect Pilot**													
32	**Less Renewable Connect MTM**													
33	**Less Renewable Connect LT**													
34														
35	**Net System Costs**													
36														**PROTECTED DATA ENDS]**
37	**Net System Sales**													
38	Calendar Month MWh Sales													
39														
40	**Less Renewable Connect Pilot MWh Sales**													
41	**Less Renewable Connect MTM MWh Sales**													
42	**Less Renewable Connect LT MWh Sales**													
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44	**Net Sys MWh Sales**													
45														
46	**System Cost in cents/kWh**													
47														
48	**Minnesota Juris. MWh Sales**													
49														
50	**Less Renewable Connect Pilot MWh Sales**													
51	**Less Renewable Connect MTM MWh Sales**													
52	**Less Renewable Connect LT MWh Sales**													
53														
54	**Net MN MWh Sales**													
55														
56	**MN Fuel Cost**													
57	**Solar Gardens - Above Market Cost**													
58	**Laurentian Buyout costs**													
59	**Pine Bend Buyout Cost**													
60	**Benson Buyout Cost**													
61														
62	**Forecast MN FCA Costs**													
63														
64														
65	**Forecast MN FCA Cost in cents/kWh**													
66														
67														
68	**Forecast MN FCA Cost in $/MWh**													

Northern States Power Company
Electric Utility - State of Minnesota

Jan 2023 - Dec 2026

Protected Data Shaded

Line #	**Updated 4-1-2021**													
1	*Energy in GWhs*	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	2023 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	84.5	121.7	173.2	201.4	237.3	210.8	251.5	242.3	171.7	136.2	93.0	75.2	1,998.7
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]

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2023 - Dec 2026

Protected Data Shaded

Line #	**Updated 4-1-2021**													
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	103.2	153.5	207.0	238.3	278.2	245.0	289.9	277.3	195.2	153.8	104.3	83.8	2,329.5
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**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2023 - Dec 2026
Updated 4-1-2021

Protected Data Shaded

Line #	*Energy in GWhs*	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	114.7	162.6	228.2	261.9	304.6	267.4	315.4	300.6	210.9	165.7	112.1	89.8	2,533.8
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**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2023 - Dec 2026
Updated 4-1-2021

Protected Data Shaded

Line #	*Energy in GWhs*	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	122.3	172.7	241.4	276.0	319.9	280.0	329.2	312.9	218.9	171.5	115.7	92.5	2,653.0
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 GWh**													
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 2023 - Dec 2026

Protected Data Shaded

Line #	Updated 4-1-2021													
1	*$/MWh*	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	2023 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	$126.72	$126.72	$126.72	$126.72	$126.72	$126.72	$126.72	$126.72	$126.72	$126.72	$126.72	$126.72	$126.72
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**													
30	**Renewable Connect Pilot**													
31	**Renewable Connect MTM**													
32	**Renewable Connect LT**													
33														
34	**Net System $/MWh**													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2023 - Dec 2026
Protected Data Shaded

Line #	Updated 4-1-2021													
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	$126.98	$126.98	$126.98	$126.98	$126.98	$126.98	$126.98	$126.98	$126.98	$126.98	$126.98	$126.98	$126.98
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**													
30	**Renewable Connect Pilot**													
31	**Renewable Connect MTM**													
32	**Renewable Connect LT**													
33														
34	**Net System $/MWh**													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2023 - Dec 2026

Protected Data Shaded

Line #	**Updated 4-1-2021**													
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	$127.05	$127.05	$127.05	$127.05	$127.05	$127.05	$127.05	$127.05	$127.05	$127.05	$127.05	$127.05	$127.05
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**													
30	**Renewable Connect 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 2023 - Dec 2026

Protected Data Shaded

Line #	Updated 4-1-2021													
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	$128.68	$128.68	$128.68	$128.68	$128.68	$128.68	$128.68	$128.68	$128.68	$128.68	$128.68	$128.68	$128.68
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**													
30	**Renewable Connect 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-21-295
Petition
Part E, Attachment 4

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2023

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Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2023 Total AVG
		[PROTECTED DATA BEGINS												
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	Coal													
Bay Front 5	Gas													
Bay Front 5	Wood													
Bay Front 6	Coal													
Bay Front 6	Gas													
Bay Front 6	Wood													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	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													
CT Invenergy 1	Gas													
CT Invenergy 1	Oil													
CT Invenergy 2	Gas													
CT Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1F	Oil													
Inver Hills 1G	Gas													
Inver Hills 2F	Oil													
Inver Hills 2G	Gas													
Inver Hills 3F	Oil													
Inver Hills 3G	Gas													
Inver Hills 4F	Oil													
Inver Hills 4G	Gas													
Inver Hills 5F	Oil													
Inver Hills 5G	Gas													
Inver Hills 6F	Oil													
Inver Hills 6G	Gas													
Inver Hills	AVG COST													
LS Power	AVG COST													
CC MEC I	Gas													
CC MEC II	Gas													
MEC	AVG COST													
Red Wing 1	RDF													
Red Wing 1	Gas													
Red Wing 2	RDF													
Red Wing 2	Gas													
Red Wing	AVG COST													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 1	Oil													
Sherburne 2	Coal													
Sherburne 2	Oil													
Sherburne 3	Coal													
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	AVG COST													
Willmarth 1	RDF													
Willmarth 1	Gas													
Willmarth 2	RDF													
Willmarth 2	Gas													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

PROTECTED DATA ENDS]

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

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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	Coal													
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	Coal													
Bay Front 5	Gas													
Bay Front 5	Wood													
Bay Front 6	Coal													
Bay Front 6	Gas													
Bay Front 6	Wood													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	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													
CT Invenergy 1	Gas													
CT Invenergy 1	Oil													
CT Invenergy 2	Gas													
CT Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1F	Oil													
Inver Hills 1G	Gas													
Inver Hills 2F	Oil													
Inver Hills 2G	Gas													
Inver Hills 3F	Oil													
Inver Hills 3G	Gas													
Inver Hills 4F	Oil													
Inver Hills 4G	Gas													
Inver Hills 5F	Oil													
Inver Hills 5G	Gas													
Inver Hills 6F	Oil													
Inver Hills 6G	Gas													
Inver Hills	AVG COST													
LS Power	AVG COST													
CC MEC I	Gas													
CC MEC II	Gas													
MEC	AVG COST													
Red Wing 1	RDF													
Red Wing 1	Gas													
Red Wing 2	RDF													
Red Wing 2	Gas													
Red Wing	AVG COST													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 1	Oil													
Sherburne 2	Coal													
Sherburne 2	Oil													
Sherburne 3	Coal													
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	AVG COST													
Willmarth 1	RDF													
Willmarth 1	Gas													
Willmarth 2	RDF													
Willmarth 2	Gas													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

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Northern States Power Company
Electric Operations - State of Minnesota

Docket No. E002/AA-21-295
Petition
Part E, Attachment 4

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

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[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	Coal													
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	Coal													
Bay Front 5	Gas													
Bay Front 5	Wood													
Bay Front 6	Coal													
Bay Front 6	Gas													
Bay Front 6	Wood													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	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													
CT Invenergy 1	Gas													
CT Invenergy 1	Oil													
CT Invenergy 2	Gas													
CT Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1F	Oil													
Inver Hills 1G	Gas													
Inver Hills 2F	Oil													
Inver Hills 2G	Gas													
Inver Hills 3F	Oil													
Inver Hills 3G	Gas													
Inver Hills 4F	Oil													
Inver Hills 4G	Gas													
Inver Hills 5F	Oil													
Inver Hills 5G	Gas													
Inver Hills 6F	Oil													
Inver Hills 6G	Gas													
Inver Hills	AVG COST													
LS Power	AVG COST													
CC MEC I	Gas													
CC MEC II	Gas													
MEC	AVG COST													
Red Wing 1	RDF													
Red Wing 1	Gas													
Red Wing 2	RDF													
Red Wing 2	Gas													
Red Wing	AVG COST													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 1	Oil													
Sherburne 2	Coal													
Sherburne 2	Oil													
Sherburne 3	Coal													
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	AVG COST													
Willmarth 1	RDF													
Willmarth 1	Gas													
Willmarth 2	RDF													
Willmarth 2	Gas													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

PROTECTED DATA ENDS]

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

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[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	Coal													
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	Coal													
Bay Front 5	Gas													
Bay Front 5	Wood													
Bay Front 6	Coal													
Bay Front 6	Gas													
Bay Front 6	Wood													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	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													
CT Invenergy 1	Gas													
CT Invenergy 1	Oil													
CT Invenergy 2	Gas													
CT Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1F	Oil													
Inver Hills 1G	Gas													
Inver Hills 2F	Oil													
Inver Hills 2G	Gas													
Inver Hills 3F	Oil													
Inver Hills 3G	Gas													
Inver Hills 4F	Oil													
Inver Hills 4G	Gas													
Inver Hills 5F	Oil													
Inver Hills 5G	Gas													
Inver Hills 6F	Oil													
Inver Hills 6G	Gas													
Inver Hills	AVG COST													
LS Power	AVG COST													
CC MEC I	Gas													
CC MEC II	Gas													
MEC	AVG COST													
Red Wing 1	RDF													
Red Wing 1	Gas													
Red Wing 2	RDF													
Red Wing 2	Gas													
Red Wing	AVG COST													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 1	Oil													
Sherburne 2	Coal													
Sherburne 2	Oil													
Sherburne 3	Coal													
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	AVG COST													
Willmarth 1	RDF													
Willmarth 1	Gas													
Willmarth 2	RDF													
Willmarth 2	Gas													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

PROTECTED DATA ENDS]

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Northern States Power Company
Electric Operations - State of Minnesota

Coal Expense
$/Mbtu
2023

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2023
	[PROTECTED DATA BEGINS												
Allen S King													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													
													PROTECTED DATA ENDS]

Coal Expense
$/Mbtu
2024

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Allen S King													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

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Electric Operations - State of Minnesota

Coal Expense
$/Mbtu
2025

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Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2025
	[PROTECTED DATA BEGINS												
Allen S King													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

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PUBLIC DOCUMENT
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Coal Expense
$/Mbtu
2026

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2026
	[PROTECTED DATA BEGINS												
Allen S King													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

PROTECTED DATA ENDS]

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

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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												
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26	Prairie Island 2 - Refueling Outage End Date												
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28	Prairie Island 2 - Fuel Expense - Dollars												
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30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
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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												
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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												
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68	Prairie Island 2 - EOL Recovery Expense - Dollars												
69	Monticello - EOL Recovery Expense - Dollars												

PROTECTED DATA ENDS]

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

Docket No. E002/AA-21-295
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Part E, Attachment 6

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17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
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Nuclear Fuel Expense (Units noted in row)

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2023 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	5,811	3,679,396	85.11%
February	5,326	3,197,584	89.35%
March	5,250	3,522,941	90.19%
April	4,833	3,121,732	89.72%
May	5,855	3,293,703	75.61%
June	7,949	3,590,641	62.73%
July	9,010	4,118,802	61.44%
August	8,534	3,992,191	62.88%
September	6,953	3,289,430	65.71%
October	5,167	3,289,114	85.56%
November	5,246	3,216,540	85.16%
December	5,764	3,567,605	83.19%
Annual	**9,010**	**41,879,679**	**53.06%**

2024 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	5,777	3,659,161	85.13%
February	5,237	3,302,496	90.60%
March	5,290	3,504,638	89.05%
April	4,891	3,102,243	88.10%
May	5,762	3,274,195	76.38%
June	7,940	3,569,195	62.43%
July	9,023	4,099,285	61.06%
August	8,546	3,973,403	62.49%
September	6,899	3,272,868	65.89%
October	5,133	3,273,058	85.71%
November	5,208	3,199,283	85.32%
December	5,732	3,550,586	83.25%
Annual	**9,023**	**41,780,412**	**52.71%**

2025 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	5,736	3,667,121	85.93%
February	5,180	3,187,765	91.57%
March	5,247	3,516,124	90.07%
April	4,841	3,114,404	89.36%
May	5,710	3,287,866	77.40%
June	7,938	3,580,727	62.65%
July	9,034	4,110,095	61.15%
August	8,560	3,983,083	62.55%
September	6,862	3,282,982	66.45%
October	5,100	3,283,965	86.55%
November	5,176	3,208,936	86.10%
December	5,704	3,559,588	83.88%
Annual	**9,034**	**41,782,655**	**52.80%**

2026 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	5,716	3,663,185	86.14%
February	5,151	3,185,451	92.03%
March	5,216	3,512,190	90.51%
April	4,794	3,108,777	90.07%
May	5,664	3,282,039	77.88%
June	7,934	3,571,889	62.53%
July	9,039	4,100,077	60.97%
August	8,566	3,971,620	62.32%
September	6,814	3,271,444	66.68%
October	5,052	3,273,057	87.07%
November	5,126	3,197,351	86.63%
December	5,656	3,547,637	84.31%
Annual	**9,039**	**41,684,715**	**52.64%**

Estimated Load Management Impact

Summer Peak (MW)

	System Base Peak	Total Load Mgmt/ Load Relief	Net Peak
2022	8,992	673	8,319
2023	9,010	679	8,331
2024	9,023	683	8,340
2025	9,034	685	8,349
2026	9,039	687	8,352

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	Laurentian Recovery
Workpaper 7	NSP Solar Gardens Forecast
Workpaper 8	NSP Solar Gardens Price Forecast
Workpaper 9	NSP Wind Curtailment Cost
Workpaper 10	Forced Outage Calculation for Baseload and Intermediate Plants
Workpaper 11	Renewable*Connect Program

CERTIFICATE OF SERVICE

I, Lynnette Sweet, 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-21-295
E002/GR-13-868
E002/GR-15-826
Miscellaneous Electric

Dated this 30th day of April 2021

/s/
____
Lynnette Sweet
Regulatory Administrator

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