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Minneapolis, MN 55401

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July 30, 2025

—Via Electronic Filing—

Mike Bull
Acting Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: REPLY COMMENTS
2026 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES
DOCKET NO. E002/AA-25-63

Dear Mr. Bull:

Northern States Power Company, doing business as Xcel Energy, submits this Reply to the June 30, 2025 Comments of the Minnesota Department of Commerce, Division of Energy Resources in the above-referenced docket. The Company provides additional information as requested by the Department and updates several inputs to our forecast.

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

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

Sincerely,

/s/

LISA R. PETERSON

DIRECTOR, REGULATORY PRICING & ANALYSIS

Enclosures

cc: Service List

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey C. Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF
NORTHERN STATES POWER COMPANY
FOR APPROVAL OF THE 2026 ANNUAL
FUEL FORECAST AND MONTHLY FUEL
COST CHARGES

DOCKET NO. E002/AA-25-63

REPLY COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this Reply to the Minnesota Department of Commerce – Division of Energy Resource’s June 30, 2025 Comments regarding our Petition requesting approval of the 2026 monthly Fuel Clause Adjustment (FCA) rates and associated forecast in the above-referenced docket.

We appreciate the Department’s thorough review of the Company’s 2026 fuel forecast and proposed rates and its recommendation that the Commission accept the Company’s compliance items and many of the inputs used in our forecast. In this Reply, we provide additional information as requested by the Department and update several inputs to our forecast model. The updates to model inputs result in a decrease of \$0.2 million in forecast 2026 fuel costs, and a decrease of \$0.01/MWh to the forecast annual average rate to \$32.19/MWh compared to our initial Petition.

REPLY COMMENTS

A. Nuclear Production Tax Credits (PTCs)

The first year of available nuclear PTCs was 2024, and the Company reported its 2024 nuclear PTC value in our March 3, 2025 FCA true-up filing in Docket No. E002/AA-23-153. The value of the nuclear PTCs allocated to Minnesota for 2024 was \$175.8 million, inclusive of transaction costs. In the 2026 FCA forecast, we estimated a

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nuclear PTC value for Minnesota ratepayers of **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. In response to DOC Information Request (IR) No. 2 in the instant docket, we provided updated forecasts of nuclear PTCs for 2025 and 2026. We explained that the reduction in forecasted nuclear PTCs compared to 2024 actuals is attributable to higher annual gross receipts and an increased forecast for the Locational Marginal Pricing (LMP).

In Comments, the Department concluded that we reasonably explained the discrepancy between actual and forecasted nuclear PTCs. However, since the Company has indicated its expectation to sell all the nuclear PTCs, the Department requested we provide in Reply Comments an analysis of the costs and benefits of transferring versus not transferring these credits.

As with other PTCs generated by the Company's resources, we are returning the value of the nuclear PTCs to our customers in a timely manner and maximizing the benefit. The value of the credits is subject to a sliding scale based on the revenue generated by the nuclear facilities, measured based on the LMP of energy, with the value of the credit diminishing as the LMP rises.

Returning the net PTC benefit to ratepayers through the FCA, minus the transfer costs, is consistent with the Company's methodology for returning PTC-transfer benefits of wind and solar PTCs as discussed in our Renewable Energy Standard (RES) Rider Petition in Docket Nos. E002/M-23-454 and E002/M-24-353, though through the FCA Rider where nuclear fuel costs are recovered. Similar to the information provided in the RES Rider proceeding, the rate base benefit of selling PTCs has a cumulative impact that is expected to greatly exceed the reduced benefit of providing only net PTCs in the FCA.

The Company intends to sell nuclear PTCs for the 2025 tax year in calendar year 2026. However, the Company will not know the value of the 2025 tax year PTCs until 2025 is over. As a result, an analysis showing the benefit to ratepayers is not possible at this time; however, the Company intends to pass the benefits back to customers through the FCA. Nuclear PTCs for the 2026 tax year are intended to be sold in calendar year 2027, though we have already offset fuel rates for 2026 by including an estimate of nuclear PTCs in the 2026 Fuel Forecast. Customers will therefore see the benefit from 2026 nuclear PTCs before they are sold through reduced fuel costs in 2026.

As noted in our response to DOC IR No. 2, 2026 nuclear PTCs are forecasted as an annual calculation based on both generation data and annual gross receipts that have

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been forecasted for 2026. Additionally, there is a phaseout of the credit based on annual gross receipts (which are calculated as generation multiplied by LMP). This phaseout begins when LMPs exceed \$25/MWh. 2026 LMPs are forecasted to be **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.¹

If gross receipts during the first half of the year are below the phaseout threshold, it would indicate that the Company would be able to claim the PTCs. However, if gross receipts increased during the second half of the year due to higher market prices, this would reduce and could eliminate any credit for the entire year. By contrast, when the Company produces and sells power from a qualifying wind facility, for example, the Company immediately earns the right to claim the PTC, regardless of market prices or any other activity during the remainder of the year. On an annual basis, the actual PTC benefits will almost certainly be different than the amounts assumed at forecast. This difference occurs because production varies from year to year, and the production levels are based on averages. The actual production could also be impacted by transmission congestion or other factors outside the Company's control.

The Company includes a forecast of the value of likely PTC sales or transfers based on our experience in the transfer market. This forecast will be trued-up in the March 1 annual True-Up filing based on the results of actual transfers. This process incentivizes the Company to maximize the value of tax credits for customers, while allowing us to recover our actual costs for participating in the tax credit market.

Additionally, PTC carryforwards are recorded as a deferred tax asset (DTA). This DTA is included in rate base as an asset on which customers are paying a return. By selling the PTCs (i.e., transferring to a third-party buyer), we are reducing the DTA for which customers are paying this carrying cost. Over time, it is expected that the savings for customers on the reduced DTA will outweigh the transaction costs of the PTC sales. Additionally, as the Company accelerates the monetization of the PTCs through sale transactions, it reduces the Company's need for financing.

B. MISO Costs and Revenue – Congestion Costs

In Comments, the Department acknowledges the congestion reduction in the 2026 forecast but remains concerned that the projected congestion costs are still materially higher than actual costs realized in most recent years 2023 and 2024. The Department

¹ We note that we have not updated the nuclear PTC forecast in the updated forecast included with this Reply, and so this LMP is as provided in our May 1 initial Petition.

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therefore requested we explain in Reply how our forecasted congestion costs methodology is reasonable and in the public interest.

The Company uses the average of congestion costs since April 2021 through the most current month available to capture some, but not all, of the volatility and uncertainty in the market. The Company selected the historical period for this case to capture a long enough period to reflect the volatility that has existed in congestion costs and Financial Transmission Rights (FTR) revenues due to the contributing factors mentioned above. The Company is still concerned that it could under-forecast these costs in 2026 due to changes in transmission availability, new renewable additions, generator retirements, and volatility of fuel prices both for our system and elsewhere in the MISO footprint.

As discussed in the Company's response to DOC IR No. 1 in this docket, because congestion costs and FTR revenues are volatile and difficult to predict, the Company continues to support its current forecast model and continues to believe it is reasonable and in the public interest. The volatility and unpredictability stems from the impact of numerous factors, including transmission outages both planned and unplanned (e.g. storm related, etc.), new renewable additions, generator retirements, and fuel prices, in particular natural gas. Although the Company has insight into some factors for the 2026 test period for its own resources, it does not have this insight for other market participants in MISO, which compounds the difficulty to predict these costs for 2026.

The Company is also working to address congestion costs and the FTR revenue issue specifically. In particular, we are working with MISO and other stakeholders to improve congestion management through Auction Revenue Rights (ARR) and FTR reform.² The reforms will 1) ensure Load Serving Entities and Market Participants have access to the financial hedges necessary to protect rate-payers; 2) improve FTR market performance – participation, model accuracy (e.g., outages, model updates), results, funding, and increased alignment to the day-ahead market; and 3) better position the ARR/FTR markets to function efficiently with the evolving energy usage and congestion patterns, driven by the ongoing fleet transition and expected data center load increases. These reforms are being discussed in the MISO Markets Subcommittee (MSC) with planned implementation in late 2026.

Congestion costs are inherent to the functioning of the MISO energy market, and the variability in congestion costs is more of a systemic than a singular change. Because

² FTR/ARR Markets Enhancements Proposal (MSC-2025-5) from Market Subcommittee July 10, 2025 meeting.

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we anticipate that higher congestion costs will persist, the Company continues its work to identify ways to mitigate these costs through transmission operation and expansion on a system level.

The increased costs are impacted by many aspects of system operations, but the common factor is that the transmission system in the Upper Midwest is over-subscribed. In other words, there is more low-cost generation installed in the western subregion of MISO than can be delivered to meet customer demand throughout the MISO footprint. To address this common factor in the long term, a cost-effective plan for transmission expansion must be implemented. Below, we discuss the current projects in construction, as well as necessary long-term, near- and medium-term partial solutions to the problem.

Current Projects in Construction: The Commission approved the Certificate of Need and Minor Alteration Route Permit for the Brookings Second Circuit project on May 31, 2024 in Docket No. E002/CN-23-200. Installation of the second circuit will reduce transmission system congestion and enable more renewable energy to be delivered to customers, resulting in savings each year. The project began construction on the western segment in mid-2024 and the eastern segment in 2025.

The Brookings Second Circuit Project will address one of the most electrically congested areas in Minnesota utilizing existing infrastructure and thereby reducing energy costs. Low-cost renewable energy generated in South Dakota, North Dakota, and Minnesota faces congestion when flowing to load centers such as the Twin Cities metropolitan area. When this congestion occurs, the cost of electricity increases due to congestion charges because the electricity needed is taken from higher-cost generators in areas without transmission constraints. These higher costs, resulting from inefficiencies in the dispatch of generation, increase consumer costs. Levels of congestion are projected to worsen over the next 10 years as more renewable energy facilities come on-line in this area. Cost estimates show that the Project would provide adjusted production cost savings over the 63-year life of the Project of \$335 million for NSP, \$834million for MISO as a whole, \$58.73 million for Otter Tail Power, and \$174 million for Great River Energy. These figures are based on production cost and other quantifiable economic benefits on a present-value basis over the book life of the Project. The Project would also further carbon-emission reduction policy objectives.

The Project will include installation of a second 345 kilovolt (kV) circuit on double circuit-capable structures on the Minnesota portion of the Western Segment and the Eastern Segment of the Original Brookings Line. While the Project largely consists of adding the additional circuit, we will also add 11 new structures to facilitate the addition of the new circuit.

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Long-Term Solutions: The MISO Long Range Transmission Planning (LRTP) process is currently evaluating the type of cost-effective solutions to not just address existing limitations but ensure sufficient transmission capacity is available to meet the plans and goals of the MISO membership over the next twenty years. This type of planning and implementation of cost-effective transmission capacity has the capability of mitigating the increased costs being incurred recently but take years, even exceeding a decade in some instances, to take effect. To address these increased costs on a more expedited basis, alternate approaches are required.

Near-Term Solutions: The Company is currently piloting technologies commonly referred to as Grid Enhancing Technologies (GETs) that could provide some near-term relief to congestion issues. One such GET is “Smart Wires,” a power control technology that can be utilized to alter the flow of power on the grid to avoid overloading certain facilities or lines. “LineVision” is another GET that can be utilized to monitor and help optimize transmission elements by allowing for the dynamic rating of limiting elements to take advantage of additional system capacity created by cooler temperatures or increased wind speeds. While these technologies can provide significant value, they are limited in their impact because they are designed only to optimize the existing system capability, not create new transmission system capacity. We are also supporting efforts in the MISO stakeholder process to develop and implement a procedure in which system optimization (temporary reconfiguration) can be analyzed and implemented in a fair and equitable fashion to ensure the reliable delivery of energy to meet customer demand.

Medium-Term Solutions: To bridge the gap between the limits of GETs and long-term transmission expansion, we have also been undertaking efforts to identify low-cost, high-impact system upgrades to target the most impactful constraints resulting in increased costs. Project #19914 (High-Bridge – Rogers Lake Bifurcation to Double Circuit) and Project #20709 (Uprate Split Rock – White 345 kV) are two projects that resulted from this analysis of low-cost, high-impact solutions that have been completed and have positively benefited congestion before a long-term solution planned at the same time could be placed in service. Additionally, any use or replacement of existing resource locations can leverage a robust system that has been designed to deliver energy to large areas of customer demand and reduce the risk of incurring additional congestion costs.

Going forward: A regular long-range transmission planning process that holistically incorporates planned system changes not normally accounted for in regional planning efforts like MTEP can ensure system limitations that cause large spikes in congestion costs can be mitigated before they become an issue or be identified as areas in which incurring the congestion is the more cost-effective solution than the cost of

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transmission expansion. Such a regular planning effort combined with a fair and equitable process for reviewing options for increased system flexibility would provide powerful tools to avoid future spikes in congestion costs.

C. Outage Costs

The forecasted total 2026 outage costs are **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. As a result, the Department requested we explain the change in forecasted total outage costs for 2026 compared to 2025. The drivers for the increase in forecast outage costs are 1) greater planned outage days in 2026 than 2025, and 2) higher LMP prices in 2026 than 2025. Each of these are explained in more detail below.

For 2026, there are **[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]** planned outage days in total than 2025. This is driven by **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. The 14 percent increase in planned outage days results in more GWh volume that directly impacts the planned outage cost calculation: put simply, more planned outage volume equals more outage costs. As shown in Department Table 9, Planned Outage GWh for 2026 are 22 percent higher than 2025, and the increase in planned outage days discussed above is the primary contributor.

For 2026, forecast LMP is 23 percent higher than 2025. The increase in LMP also significantly impacts the outage cost calculation as it drives the estimate of replacement power costs higher and increases the spread between the unit cost of the generators and the replacement power cost. Department Table 9 shows that the increase in outage cost per MWh is 17 percent higher for outages in total. The 17 percent increase is a direct result of the increase in forecast LMP discussed.

Another impact of higher LMP is more outage GWh are costed. The outage cost calculation assumes costs only when LMP is higher than the unit cost of the generators. As LMPs increase, there are more generation hours where LMP is greater than the unit cost of the generation and this results in greater GWh volume of outages. Department Table 9 shows a 28 percent increase in total outage GWh and the LMP impact on volume described above is a significant contributor. Greater outage volume will result in greater outage costs.

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D. Rock Aetna Wind Information

The Department noted that the forecasted capacity factors for Rock Aetna wind farm for years 2025 and 2026 are not included in Part H, Attachment 5 and requested we explain why these forecasts were omitted.

This information is provided in Part H, Attachment 5, Page 1 of the Petition. However, Rock Aetna is called “Wind Northern RA” in the attachment, which we believe may have led to confusion. Forecasted capacity factors for 2025 and 2026 are also provided under this name in the referenced attachment.

E. Forecast Input Updates

As outlined in the procedural schedule for fuel clause reform, utilities are able to update their forecast inputs with their July Reply Comments. We have updated the inputs discussed below. These inputs include those that are significant cost drivers to any year’s fuel forecast and those that should be updated to remain true to an objective of reform. As always, our goal is to provide the most accurate forecast of test year costs that is possible at the time of Commission review.

The updates to model inputs result in a decrease of \$0.2 million in forecast 2026 fuel costs, and a decrease of \$0.01/MWh to the forecast annual average rate to \$32.19/MWh. We provide Attachments A, B, and C to summarize the updated forecast, which correspond to Part A, Attachments 1, 2, and 3 of the May 1 forecast filing.

1. Coal Pricing

Market prices and escalation assumptions for coal and rail were updated for our Reply. Forecast coal generation prices have increased for this Reply update and are compared to our original filing in Attachment D. The overall impact on coal generation cost/MWh is an increase of 1.0 percent as compared to our original filing.

2. Natural Gas Prices

Natural gas prices have been updated to NYMEX closing prices as of July 9, 2025. The annual average price of natural gas for Ventura has decreased to \$4.13/MMBtu, which is 3.9 percent lower than our original filing. A comparison of the updated monthly natural gas prices to the prices assumed in our original May 1 filing is shown in Attachment E.

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3. *Electric Market Prices*

Our price forecast for MISO LMP has been updated to correspond with the date of the updated natural gas prices from market close on July 9, 2025. The average annual price has decreased to \$38.37/MWh, which is 2.1 percent lower than our original filing. A comparison of the updated monthly LMPs to the LMPs assumed in our original May 1 filing is shown in Attachment E.

4. *MISO Costs*

We updated MISO costs based on the most recent historical data available through June 2025. Details on the updated costs by MISO charge type are shown in Attachment F. The net of MISO Day 2 and Day 3 costs and revenues in the Reply forecast is **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** resulting in a **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** from the initial filing forecast of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. The primary driver of **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] as shown in

Attachment F.

5. *Maintenance Updates*

We have updated planned maintenance for 2025 for our Reply to reflect the latest planned schedules for our generating plants. Our 2025 updated replacement power cost estimate for this Reply filing is provided as Attachment G. The most significant change in planned maintenance is **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS].

6. *PPA Updates*

We have updated PPA contracts for 2025 to reflect changes that have occurred since our initial filing. The primary change is **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] for our Reply filing.

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F. Revised Rate Summary

1. *Community Solar Garden Net Cost Exclusion Rate*

The updated fuel forecast impacts the calculation of the CSG exclusion credit. We have updated our calculation to this credit by dividing forecasted Residential CSG above market costs by the forecasted Residential FCA kWh. Based on the updated fuel forecast, the Company has calculated the net cost of generation for CSGs as 0.590 cents per kWh for 2026.

2. *Proposed Monthly Fuel Clause Rates by Customer Class*

Tables 1 and 2 below summarize the rates by month and by customer class revised to reflect the updated 2026 forecast inputs using the Class Ratio Adjustment. See Attachment A, pages 2, 3, and 4 for details.

Table 1
Revised 2026 Monthly Fuel Clause Rates by Customer Class (\$/kWh)

Month	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
January	\$0.02057	\$0.02055	\$0.02024	\$0.02571	\$0.01615	\$0.01547
February	\$0.02122	\$0.02120	\$0.02088	\$0.02654	\$0.01666	\$0.01595
March	\$0.02216	\$0.02214	\$0.02180	\$0.02771	\$0.01740	\$0.01665
April	\$0.03189	\$0.03186	\$0.03138	\$0.03987	\$0.02505	\$0.02398
May	\$0.03305	\$0.03302	\$0.03253	\$0.04133	\$0.02595	\$0.02485
June	\$0.03513	\$0.03510	\$0.03457	\$0.04394	\$0.02758	\$0.02640
July	\$0.03386	\$0.03383	\$0.03332	\$0.04236	\$0.02657	\$0.02543
August	\$0.03269	\$0.03266	\$0.03217	\$0.04089	\$0.02565	\$0.02455
September	\$0.03036	\$0.03033	\$0.02988	\$0.03796	\$0.02384	\$0.02282
October	\$0.02863	\$0.02860	\$0.02817	\$0.03579	\$0.02248	\$0.02153
November	\$0.02558	\$0.02556	\$0.02518	\$0.03199	\$0.02009	\$0.01923
December	\$0.02706	\$0.02704	\$0.02663	\$0.03384	\$0.02125	\$0.02034

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Table 2
Revised 2026 Monthly Fuel Clause Rates for
C&I General Time of Use Service Pilot (\$/kWh)

Month	Commercial & Industrial General TOU Service Pilot		
	Demand		
	Peak	Base	Off-Peak
January	\$0.02669	\$0.02152	\$0.01059
February	\$0.02754	\$0.02221	\$0.01091
March	\$0.02876	\$0.02318	\$0.01139
April	\$0.04138	\$0.03337	\$0.01642
May	\$0.04290	\$0.03458	\$0.01700
June	\$0.04561	\$0.03676	\$0.01805
July	\$0.04397	\$0.03543	\$0.01738
August	\$0.04244	\$0.03421	\$0.01678
September	\$0.03941	\$0.03177	\$0.01562
October	\$0.03715	\$0.02995	\$0.01474
November	\$0.03320	\$0.02677	\$0.01316
December	\$0.03512	\$0.02831	\$0.01392

We provide as Attachment H updated redline and clean tariff sheets reflecting our updated rate proposal, including the updated exclusion rate. We will make a tariff compliance filing within 10 days of the Commission Order in this docket to reflect the final approved rates, to be effective January 1.

CONCLUSION

The Company appreciates this opportunity to submit its Reply to the Department's review of our 2026 Fuel Forecast. Through this Reply, we have provided additional information in response to the questions raised by the Department and have updated several inputs to the 2026 forecast. We respectfully request that the Commission approve Xcel Energy's 2026 Annual Fuel Forecast and resulting proposed monthly fuel cost charges for the months January-December 2026 as updated and supplemented by this Reply.

Dated: July 30, 2025

Northern States Power Company

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

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Line #		01/01/2026	02/01/2026	03/01/2026	04/01/2026	05/01/2026	06/01/2026	07/01/2026	08/01/2026	09/01/2026	10/01/2026	11/01/2026	12/01/2026	2026 Total
1	Costs in \$1,000's													
2														
3	Own Generation													
4	Fossil Fuel	[PROTECTED DATA BEGINS]												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	Purchased Energy													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens (CSG)	\$8,714	\$14,883	\$23,191	\$25,595	\$31,285	\$33,469	\$33,823	\$29,775	\$24,195	\$17,515	\$9,958	\$6,278	\$258,680
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	MISO Market Charges													
25	Subtotal													
26														
27	Total NSP System Costs													
28														
29	Less Sales Revenue													
30	Less Solar Gardens - Above Market Cost	(\$4,900)	(\$8,757)	(\$16,967)	(\$18,443)	(\$22,376)	(\$21,705)	(\$17,984)	(\$16,246)	(\$15,660)	(\$11,400)	(\$6,858)	(\$3,939)	(\$165,235)
31	Less Renewable*Connect Pilot													
32	Less Renewable*Connect Flex (MTM)													
33	Less Renewable*Connect LT													
34														
35	NSP Net System Costs Excluded CSG Above Market													
36	& Renewable*Connect Costs													
37														
38	Interchange Agreement Energy Req Allocator													
39														
40	NSPM System Costs Excluded CSG Above Market													
41	& Renewable*Connect Costs													
42														
43	NSPM System Calendar Month MWh Sales													
44														
45	Less Renewable*Connect Pilot MWh Sales													
46	Less Renewable*Connect Flex (MTM) MWh Sales													
47	Less Renewable*Connect LT MWh Sales													
48														
49	Net NSPM System Calendar Month MWh Sales													31,883,904
50														
51	NSPM System Cost in cents/kWh													
52														
53	Minnesota Jurisdiction MWh Sales													
54														
55	Less Renewable*Connect Pilot MWh Sales													
56	Less Renewable*Connect Flex (MTM) MWh Sales													
57	Less Renewable*Connect LT MWh Sales													
58														
59	Net MN MWh Sales													27,434,341
60														
61	MN Fuel Cost													
62	Solar Gardens - Above Market Cost	\$4,900	\$8,757	\$16,967	\$18,443	\$22,376	\$21,705	\$17,984	\$16,246	\$15,660	\$11,400	\$6,858	\$3,939	\$165,235
63	Benson Buyout Cost													
64														
65	Forecast MN FCA Costs													\$883,068
66														
67														
68	Forecast MN FCA Cost in cents/kWh													3.219
69														
70														
71	Forecast MN FCA Cost in \$/MWh													32.19
72	Forecast MN Nuclear PTCs													
73	Total MN FCA Costs including MN Nuclear PTCs													\$831,951
74	Forecast MN FCA Cost incl. NPTCs in cents/kWh													3.033
75	Forecast MN FCA Cost incl. NPTCs in \$/MWh													30.33

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Northern States Power Company
Electric Utility - State of Minnesota

Docket No. E002/AA-25-63
Reply Comments Attachment A
Corresponds to May 1 Part A, Attachment 1
Page 2 of 4

Proposed 2026 Monthly Fuel Clause Charges with 2024 True-Ups and NPTCs (\$/kWh) - July 31 Update

	Residential	Commercial & Industrial				Outdoor Lighting	Commercial & Industrial General TOUService Pilot		
		Non-Demand	Demand				Demand		
			Non-TOD	On-Peak	Off-Peak		Peak	Base	Off-Peak
January									
Forecast	\$0.02910	\$0.02907	\$0.02864	\$0.03638	\$0.02285	\$0.02188	\$0.03776	\$0.03045	\$0.01498
2024 True-Up	(\$0.00174)	(\$0.00174)	(\$0.00172)	(\$0.00218)	(\$0.00137)	(\$0.00131)	(\$0.00226)	(\$0.00182)	(\$0.00090)
2024 NPTCs	<u>(\$0.00679)</u>	<u>(\$0.00678)</u>	<u>(\$0.00668)</u>	<u>(\$0.00849)</u>	<u>(\$0.00533)</u>	<u>(\$0.00510)</u>	<u>(\$0.00881)</u>	<u>(\$0.00710)</u>	<u>(\$0.00349)</u>
Total	\$0.02057	\$0.02055	\$0.02024	\$0.02571	\$0.01615	\$0.01547	\$0.02669	\$0.02152	\$0.01059
February									
Forecast	\$0.03109	\$0.03106	\$0.03059	\$0.03888	\$0.02440	\$0.02336	\$0.04035	\$0.03253	\$0.01598
2024 True-Up	(\$0.00201)	(\$0.00201)	(\$0.00198)	(\$0.00251)	(\$0.00158)	(\$0.00151)	(\$0.00261)	(\$0.00210)	(\$0.00103)
2024 NPTCs	<u>(\$0.00786)</u>	<u>(\$0.00785)</u>	<u>(\$0.00773)</u>	<u>(\$0.00983)</u>	<u>(\$0.00617)</u>	<u>(\$0.00591)</u>	<u>(\$0.01020)</u>	<u>(\$0.00822)</u>	<u>(\$0.00404)</u>
Total	\$0.02122	\$0.02120	\$0.02088	\$0.02654	\$0.01666	\$0.01595	\$0.02754	\$0.02221	\$0.01091
March									
Forecast	\$0.03117	\$0.03114	\$0.03067	\$0.03898	\$0.02447	\$0.02342	\$0.04046	\$0.03261	\$0.01602
2024 True-Up	(\$0.00183)	(\$0.00183)	(\$0.00181)	(\$0.00229)	(\$0.00144)	(\$0.00138)	(\$0.00238)	(\$0.00192)	(\$0.00094)
2024 NPTCs	<u>(\$0.00718)</u>	<u>(\$0.00717)</u>	<u>(\$0.00706)</u>	<u>(\$0.00897)</u>	<u>(\$0.00563)</u>	<u>(\$0.00539)</u>	<u>(\$0.00931)</u>	<u>(\$0.00751)</u>	<u>(\$0.00369)</u>
Total	\$0.02216	\$0.02214	\$0.02180	\$0.02771	\$0.01740	\$0.01665	\$0.02876	\$0.02318	\$0.01139
April									
Forecast	\$0.03189	\$0.03186	\$0.03138	\$0.03987	\$0.02505	\$0.02398	\$0.04138	\$0.03337	\$0.01642
May									
Forecast	\$0.03305	\$0.03302	\$0.03253	\$0.04133	\$0.02595	\$0.02485	\$0.04290	\$0.03458	\$0.01700
June									
Forecast	\$0.03513	\$0.03510	\$0.03457	\$0.04394	\$0.02758	\$0.02640	\$0.04561	\$0.03676	\$0.01805
July									
Forecast	\$0.03386	\$0.03383	\$0.03332	\$0.04236	\$0.02657	\$0.02543	\$0.04397	\$0.03543	\$0.01738
August									
Forecast	\$0.03269	\$0.03266	\$0.03217	\$0.04089	\$0.02565	\$0.02455	\$0.04244	\$0.03421	\$0.01678
September									
Forecast	\$0.03036	\$0.03033	\$0.02988	\$0.03796	\$0.02384	\$0.02282	\$0.03941	\$0.03177	\$0.01562
October									
Forecast	\$0.02863	\$0.02860	\$0.02817	\$0.03579	\$0.02248	\$0.02153	\$0.03715	\$0.02995	\$0.01474
November									
Forecast	\$0.02558	\$0.02556	\$0.02518	\$0.03199	\$0.02009	\$0.01923	\$0.03320	\$0.02677	\$0.01316
December									
Forecast	\$0.02706	\$0.02704	\$0.02663	\$0.03384	\$0.02125	\$0.02034	\$0.03512	\$0.02831	\$0.01392

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Northern States Power Company
Electric Utility - State of Minnesota
Monthly Fuel Clause Charge January 2026 - December 2026

Docket No. E002/AA-25-63
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Protected Data is shaded.

Month Fuel Cost Charges Applied to Customer Billing														
Jan-26														
Feb-26														
Mar-26														
Apr-26														
May-26														
Jun-26														
Jul-26														
Aug-26														
Sep-26														
Oct-26														
Nov-26														
Dec-26														
12 Months														
FORECASTED COST OF FUEL														
[1]	Forecasted MN Cost in \$1,000's	[PROTECTED DATA BEGINS]												
[2]	Forecasted Minn. Retail Sales Subject to FCC *													
[3]	Forecasted MN Cost in cents/kWh [1]/[2]*100													
		PROTECTED DATA ENDS]												
Class FAF Ratio														
[4]	Residential FAF Ratio	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192
[5]	C&I Non-Demand FAF Ratio	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183
[6]	C & I Demand Non-TOD FAF Ratio	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030
[7]	C & I Demand TOD On-Peak FAF Ratio	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746
[8]	C & I Demand TOD Off-Peak FAF Ratio	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001
[9]	Outdoor Lighting FAF Ratio	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659
[10]	C&I Demand General TOU Peak Ratio	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230
[11]	C&I Demand General TOU Base Ratio	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0183
[12]	C&I Demand General TOU Off-Peak Ratio	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	1.0030
2026 Monthly Fuel Cost Charges		[PROTECTED DATA BEGINS]												
[13]	Residential [3]*[4]													
[14]	C & I Non-Demand [3]*[5]													
[15]	C & I Demand Non-TOD [3]*[6]													
[16]	C & I Demand TOD On-Peak [3]*[7]													
[17]	C & I Demand TOD Off-Peak [3]*[8]													
[18]	Outdoor Lighting [3]*[9]													
[19]	C&I Demand General TOU Peak [3]*[10]													
[20]	C&I Demand General TOU Base [3]*[11]													
[21]	C&I Demand General TOU Off-Peak [3]*[12]													
MN Retail MWh Subject to FCA *														
[22]	Residential													
[23]	C & I Non-Demand													
[24]	C & I Demand Non-TOD													
[25]	C & I Demand TOD On-Peak													
[26]	C & I Demand TOD Off-Peak													
[27]	Outdoor Lighting													
[28]	C&I Demand General TOU Peak													
[29]	C&I Demand General TOU Base													
[30]	C&I Demand General TOU Off-Peak													
[31]	Total													
2026 Class Fuel Cost Revenues in \$1,000's														
[32]	Residential [13]*[22]/100													
[33]	C & I Non-Demand [14]*[23]/100													
[34]	C & I Demand Non-TOD [15]*[24]/100													
[35]	C & I Demand TOD On-Peak [16]*[25]/100													
[36]	C & I Demand TOD Off-Peak [17]*[26]/100													
[37]	Outdoor Lighting [18]*[27]/100													
[38]	C & I Demand Non-TOD [19]*[28]/100													
[39]	C & I Demand TOD On-Peak [20]*[29]/100													
[40]	C & I Demand TOD Off-Peak [21]*[30]/100													
[41]	Total [32]+[33]+[34]+[35]+[36]+[37]+[38]+[39]+[40]													
[42]	2026 Cost vs Revenue Diff in \$1,000's [1]-[41]													
[43]	2026 Cost vs Revenue Diff in \$1,000's [42]													
[44]	MN Retail MWh Subject to FCA [31]													
[45]	Monthly Class Ratio Adjustment [43]/[44]*100													
PROTECTED DATA ENDS]														

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Northern States Power Company
Electric Utility - State of Minnesota
Monthly Fuel Clause Charge January 2026 - December 2026

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Month Fuel Cost Charges Applied to Customer Billing		Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	12 Months
2026 Proposed Monthly Fuel Cost Charges in \$/kWh														
[46]	Residential [13]/100+[45]/100	\$0.02910	\$0.03109	\$0.03117	\$0.03189	\$0.03305	\$0.03513	\$0.03386	\$0.03269	\$0.03036	\$0.02863	\$0.02558	\$0.02706	
[47]	C & I Non-Demand [14]/100+[45]/100	\$0.02907	\$0.03106	\$0.03114	\$0.03186	\$0.03302	\$0.03510	\$0.03383	\$0.03266	\$0.03033	\$0.02860	\$0.02556	\$0.02704	
[48]	C & I Demand Non-TOD [15]/100+[45]/100	\$0.02864	\$0.03059	\$0.03067	\$0.03138	\$0.03253	\$0.03457	\$0.03332	\$0.03217	\$0.02988	\$0.02817	\$0.02518	\$0.02663	
[49]	C & I Demand TOD On-Peak [16]/100+[45]/100	\$0.03638	\$0.03888	\$0.03898	\$0.03987	\$0.04133	\$0.04394	\$0.04236	\$0.04089	\$0.03796	\$0.03579	\$0.03199	\$0.03384	
[50]	C & I Demand TOD Off-Peak [17]/100+[45]/100	\$0.02285	\$0.02440	\$0.02447	\$0.02505	\$0.02595	\$0.02758	\$0.02657	\$0.02565	\$0.02384	\$0.02248	\$0.02009	\$0.02125	
[51]	Outdoor Lighting [18]/100+[45]/100	\$0.02188	\$0.02336	\$0.02342	\$0.02398	\$0.02485	\$0.02640	\$0.02543	\$0.02455	\$0.02282	\$0.02153	\$0.01923	\$0.02034	
[52]	C&I Demand Generl TOU Peak [19]/100+[45]/100	\$0.03776	\$0.04035	\$0.04046	\$0.04138	\$0.04290	\$0.04561	\$0.04397	\$0.04244	\$0.03941	\$0.03715	\$0.03320	\$0.03512	
[53]	C&I Demand General TOU Base [20]/100+[45]/100	\$0.03045	\$0.03253	\$0.03261	\$0.03337	\$0.03458	\$0.03676	\$0.03543	\$0.03421	\$0.03177	\$0.02995	\$0.02677	\$0.02831	
[54]	C&I Demand General TOU Off-Peak [21]/100+[45]/100	\$0.01498	\$0.01598	\$0.01602	\$0.01642	\$0.01700	\$0.01805	\$0.01738	\$0.01678	\$0.01562	\$0.01474	\$0.01316	\$0.01392	
2024 True-Up Factor by Class Category **														
[55]	Residential	-\$0.00174	-\$0.00201	-\$0.00183										
[56]	C & I Non-Demand	-\$0.00174	-\$0.00201	-\$0.00183										
[57]	C & I Demand Non-TOD	-\$0.00172	-\$0.00198	-\$0.00181										
[58]	C & I Demand TOD On-Peak	-\$0.00218	-\$0.00251	-\$0.00229										
[59]	C & I Demand TOD Off-Peak	-\$0.00137	-\$0.00158	-\$0.00144										
[60]	Outdoor Lighting	-\$0.00131	-\$0.00151	-\$0.00138										
[61]	C&I Demand Generl TOU Peak	-\$0.00226	-\$0.00261	-\$0.00238										
[62]	C&I Demand General TOU Base	-\$0.00182	-\$0.00210	-\$0.00192										
[63]	C&I Demand General TOU Off-Peak	-\$0.00090	-\$0.00103	-\$0.00094										
2024 Nuclear Production Tax Credits by Class Category **														
[64]	Residential	-\$0.00679	-\$0.00786	-\$0.00718										
[65]	C & I Non-Demand	-\$0.00678	-\$0.00785	-\$0.00717										
[66]	C & I Demand Non-TOD	-\$0.00668	-\$0.00773	-\$0.00706										
[67]	C & I Demand TOD On-Peak	-\$0.00849	-\$0.00983	-\$0.00897										
[68]	C & I Demand TOD Off-Peak	-\$0.00533	-\$0.00617	-\$0.00563										
[69]	Outdoor Lighting	-\$0.00510	-\$0.00591	-\$0.00539										
[70]	C&I Demand Generl TOU Peak	-\$0.00881	-\$0.01020	-\$0.00931										
[71]	C&I Demand General TOU Base	-\$0.00710	-\$0.00822	-\$0.00751										
[72]	C&I Demand General TOU Off-Peak	-\$0.00349	-\$0.00404	-\$0.00369										
2026 Proposed Monthly Fuel Cost Charges with 2024 True-Up and Nuclear Production Tax Credits in \$/kWh														
[73]	Residential [46]+[55]+[64]	\$0.02057	\$0.02122	\$0.02216	\$0.03189	\$0.03305	\$0.03513	\$0.03386	\$0.03269	\$0.03036	\$0.02863	\$0.02558	\$0.02706	
[74]	C & I Non-Demand [47]+[56]+[65]	\$0.02055	\$0.02120	\$0.02214	\$0.03186	\$0.03302	\$0.03510	\$0.03383	\$0.03266	\$0.03033	\$0.02860	\$0.02556	\$0.02704	
[75]	C & I Demand Non-TOD [48]+[57]+[66]	\$0.02024	\$0.02088	\$0.02180	\$0.03138	\$0.03253	\$0.03457	\$0.03332	\$0.03217	\$0.02988	\$0.02817	\$0.02518	\$0.02663	
[76]	C & I Demand TOD On-Peak [49]+[58]+[67]	\$0.02571	\$0.02654	\$0.02771	\$0.03987	\$0.04133	\$0.04394	\$0.04236	\$0.04089	\$0.03796	\$0.03579	\$0.03199	\$0.03384	
[77]	C & I Demand TOD Off-Peak [50]+[59]+[68]	\$0.01615	\$0.01666	\$0.01740	\$0.02505	\$0.02595	\$0.02758	\$0.02657	\$0.02565	\$0.02384	\$0.02248	\$0.02009	\$0.02125	
[78]	Outdoor Lighting [51]+[60]+[69]	\$0.01547	\$0.01595	\$0.01665	\$0.02398	\$0.02485	\$0.02640	\$0.02543	\$0.02455	\$0.02282	\$0.02153	\$0.01923	\$0.02034	
[79]	C&I Demand Generl TOU Peak [52]+[61]+[70]	\$0.02669	\$0.02754	\$0.02876	\$0.04138	\$0.04290	\$0.04561	\$0.04397	\$0.04244	\$0.03941	\$0.03715	\$0.03320	\$0.03512	
[80]	C&I Demand General TOU Base [53]+[62]+[71]	\$0.02152	\$0.02221	\$0.02318	\$0.03337	\$0.03458	\$0.03676	\$0.03543	\$0.03421	\$0.03177	\$0.02995	\$0.02677	\$0.02831	
[81]	C&I Demand General TOU Off-Peak [54]+[63]+[72]	\$0.01059	\$0.01091	\$0.01139	\$0.01642	\$0.01700	\$0.01805	\$0.01738	\$0.01678	\$0.01562	\$0.01474	\$0.01316	\$0.01392	

* Excluded Renewable*Connect MWh

** 2024 True-Up factors and NPTC factors were filed on March 31, 2025 in Docket No. E002/AA-23-153

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

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Line #		01/01/2026	02/01/2026	03/01/2026	04/01/2026	05/01/2026	06/01/2026	07/01/2026	08/01/2026	09/01/2026	10/01/2026	11/01/2026	12/01/2026	2026 Total
1	Energy in GWhs													
2														
3	Own Generation													
4	Fossil Fuel	[PROTECTED DATA BEGINS]												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	Purchased Energy													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	70.1	119.7	186.6	205.9	251.7	269.3	272.1	239.6	194.7	140.9	80.1	50.5	2,081.3
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 Flex (MTM) GWh													
31	Less Renewable* Connect LT GWh													
32														
33	Net System GWh													42,958.6

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 Reply Comments Attachment C
 Corresponds to May 1 Part A, Attachment 3
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Northern States Power Company
 Electric Utility - State of Minnesota
 Jan 2026 - Dec 2026

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Line #		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
1	\$/MWh													
2														
3	Own Generation													
4	Fossil Fuel	[PROTECTED DATA BEGINS]												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	Purchased Energy													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	\$124.29	\$124.29	\$124.29	\$124.29	\$124.29	\$124.29	\$124.29	\$124.29	\$124.29	\$124.29	\$124.29	\$124.29	\$124.29
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	\$69.88	\$73.13	\$90.94	\$89.56	\$88.90	\$80.60	\$66.08	\$67.82	\$80.44	\$80.90	\$85.59	\$77.99	\$79.39
30	Less Renewable*Connect Pilot													
31	Less Renewable* Connect Flex (MTM)													
32	Less Renewable*Connect LT													
33														
34	Net System \$/MWh													\$23.15

PROTECTED DATA ENDS]

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Northern States Power Company
Electric Utility - State of Minnesota
Coal Pricing - Updated July 2025

Docket No. E002/AA-25-63
Reply Comments Attachment D
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2026 Forecast Year

		Total Price				Coal Price				Rail Price				Diesel Price					
		[PROTECTED DATA BEGINS]																	
July 31 Reply Filing																			
May 1 Filing																			
Change																			

PROTECTED DATA ENDS]

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Northern States Power Company
Electric Utility - State of Minnesota
Gas and LMP Pricing - Updated July 2025

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2026 Forecast Year

Ventura \$/MMBtu			
May 1 Filing	July 31 Reply Filing	Change	
1/1/2026	6.79	6.21	
2/1/2026	6.54	5.99	
3/1/2026	4.16	3.70	
4/1/2026	3.49	3.35	
5/1/2026	3.48	3.28	
6/1/2026	3.50	3.37	
7/1/2026	3.61	3.59	
8/1/2026	3.64	3.65	
9/1/2026	3.52	3.50	
10/1/2026	3.57	3.57	
11/1/2026	4.04	4.02	
12/1/2026	5.29	5.35	
Average	4.30	4.13	-0.17
			-3.9%

LMP \$/MWh		
May 1 Filing	July 31 Reply Filing	Change
[PROTECTED DATA BEGINS]		
39.19	38.37	-0.82
PROTECTED DATA ENDS]		-2.1%

MISO Charge Category	May 1 Filing	July 31 Reply Filing	Change
(in \$1000s)	[PROTECTED DATA BEGINS]		
Congestion			
FTR			
Incremental Transmission losses			
RSG/RNU			
ASM			
TOTAL			

PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS

[REDACTED]

PROTECTED DATA ENDS]

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

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Reply Comments Attachment G
Corresponds to May 1 Part B, Attachment 7
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		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]											

Redline

MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FUEL CLAUSE RIDER (Continued)

Section No. 5
~~35th~~^{36th} Revised Sheet No. 91.1

FUEL COST FACTORS (~~2025~~²⁰²⁶)

Commercial & Industrial						
Month	Residential	Non-Demand	Non-TOD	Demand On-Peak	Off-Peak	Outdoor Lighting
January	\$0.02617 0.02057	\$0.02615 0.02055	\$0.025760.02024	\$0.03272 0.02571	\$0.02056 0.01615	\$0.01968 0.01547
February	\$0.02819 0.02122	\$0.02817 0.02120	\$0.027740.02088	\$0.03525 0.02654	\$0.02213 0.01666	\$0.02119 0.01595
March	\$0.02919 0.02216	\$0.02916 0.02214	\$0.028730.02180	\$0.03651 0.02771	\$0.02291 0.01740	\$0.02193 0.01665
April	\$0.00972 0.03189	\$0.00970 0.03186	\$0.009550.03138	\$0.01215 0.03987	\$0.00763 0.02505	\$0.00730 0.02398
May	\$0.02618 0.03305	\$0.02616 0.03302	\$0.025770.03253	\$0.03273 0.04133	\$0.02057 0.02595	\$0.01969 0.02485
June	\$0.02839 0.03513	\$0.02837 0.03510	\$0.027930.03457	\$0.03551 0.04394	\$0.02228 0.02758	\$0.02133 0.02640
July	\$0.02787 0.03386	\$0.02783 0.03383	\$0.027420.03332	\$0.03487 0.04236	\$0.02185 0.02657	\$0.02092 0.02543
August	\$0.02617 0.03269	\$0.02615 0.03266	\$0.025760.03217	\$0.03275 0.04089	\$0.02053 0.02565	\$0.01965 0.02455
September	\$0.02300 0.03036	\$0.02299 0.03033	\$0.022640.02988	\$0.02878 0.03796	\$0.01805 0.02384	\$0.01728 0.02282
October	\$0.02099 0.02863	\$0.02097 0.02860	\$0.020660.02817	\$0.02626 0.03579	\$0.01648 0.02248	\$0.01578 0.02153
November	\$0.01839 0.02558	\$0.01837 0.02556	\$0.018090.02518	\$0.02300 0.03199	\$0.01442 0.02009	\$0.01384 0.01923
December	\$0.02055 0.02706	\$0.02052 0.02704	\$0.020240.02663	\$0.02569 0.03384	\$0.01612 0.02125	\$0.01543 0.02034

Commercial & Industrial General TOU Service Pilot Program

Month	Peak	Base	Off-Peak
January	\$0.033960.02669	\$0.027380.02152	\$0.013480.01059
February	\$0.036590.02754	\$0.029590.02221	\$0.014500.01091
March	\$0.037890.02876	\$0.030550.02318	\$0.015000.01139
April	\$0.012690.04138	\$0.010170.03337	\$0.004990.01642
May	\$0.033980.04290	\$0.027490.03458	\$0.013470.01700
June	\$0.036860.04561	\$0.029790.03676	\$0.014580.01805
July	\$0.036290.04397	\$0.029160.03543	\$0.014280.01738
August	\$0.033990.04244	\$0.027490.03421	\$0.013430.01678
September	\$0.029870.03941	\$0.024070.03177	\$0.011810.01562
October	\$0.027260.03715	\$0.021970.02995	\$0.010790.01474
November	\$0.023870.03320	\$0.019250.02677	\$0.009450.01316
December	\$0.026660.03512	\$0.021490.02831	\$0.010550.01392

(Continued on Sheet No. 5-91.2)

Northern States Power Company, a Minnesota corporation

Minneapolis, Minnesota 55401

MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FUEL CLAUSE RIDER (Continued)

Section No. 5
~~35th~~36th Revised Sheet No. 91.1

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, Voluntary Renewable*Connect Program Rider (Renewable*Connect Flex), and Voluntary Renewable*Connect Program Rider (Long Term) kWh sales. Qualifying costs are the sum of the following:

(Continued on Sheet No. 5-91.2)

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EVP, Chief Legal & Compliance Officer and President, Northern States Power Company, a Minnesota corporation

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Order Date: ~~06-12-19~~

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401

MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FUEL CLAUSE RIDER (Continued)

Section No. 5
~~4st~~2nd Revised Sheet No. 91.4

EXCLUSION OF COMMUNITY SOLAR GARDEN COSTS

To comply with Minn. Stat. § 216B.1641, Subd. 11, the fuel adjustment charge to residential customers who have received bill payment assistance or income-qualified energy assistance programs within the proceeding twelve-month timeframe and who also do not subscribe to a community solar garden shall exclude the “net cost of community solar garden generation”. To achieve this exclusion, these customers shall receive a bill credit of ~~\$0.00684~~\$0.00590 per kWh of billed usage that removes “net cost of community solar garden generation”.

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Date Filed: 08-02-2407-30-25

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EVP, Chief Legal & Compliance Officer and President, Northern States Power Company, a Minnesota corporation

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FUEL CLAUSE RIDER (Continued)

Section No. 5
 36th Revised Sheet No. 91.1

FUEL COST FACTORS (2026)

Month	Residential	Commercial & Industrial				Outdoor Lighting	
		Non-Demand	Non-TOD	Demand On-Peak	Off-Peak		
January	\$0.02057	\$0.02055	\$0.02024	\$0.02571	\$0.01615	\$0.01547	R
February	\$0.02122	\$0.02120	\$0.02088	\$0.02654	\$0.01666	\$0.01595	
March	\$0.02216	\$0.02214	\$0.02180	\$0.02771	\$0.01740	\$0.01665	
April	\$0.03189	\$0.03186	\$0.03138	\$0.03987	\$0.02505	\$0.02398	
May	\$0.03305	\$0.03302	\$0.03253	\$0.04133	\$0.02595	\$0.02485	
June	\$0.03513	\$0.03510	\$0.03457	\$0.04394	\$0.02758	\$0.02640	
July	\$0.03386	\$0.03383	\$0.03332	\$0.04236	\$0.02657	\$0.02543	
August	\$0.03269	\$0.03266	\$0.03217	\$0.04089	\$0.02565	\$0.02455	
September	\$0.03036	\$0.03033	\$0.02988	\$0.03796	\$0.02384	\$0.02282	
October	\$0.02863	\$0.02860	\$0.02817	\$0.03579	\$0.02248	\$0.02153	
November	\$0.02558	\$0.02556	\$0.02518	\$0.03199	\$0.02009	\$0.01923	
December	\$0.02706	\$0.02704	\$0.02663	\$0.03384	\$0.02125	\$0.02034	

Commercial & Industrial General TOU Service Pilot Program

Month	Peak	Base	Off-Peak	
January	\$0.02669	\$0.02152	\$0.01059	R
February	\$0.02754	\$0.02221	\$0.01091	
March	\$0.02876	\$0.02318	\$0.01139	
April	\$0.04138	\$0.03337	\$0.01642	
May	\$0.04290	\$0.03458	\$0.01700	
June	\$0.04561	\$0.03676	\$0.01805	
July	\$0.04397	\$0.03543	\$0.01738	
August	\$0.04244	\$0.03421	\$0.01678	
September	\$0.03941	\$0.03177	\$0.01562	
October	\$0.03715	\$0.02995	\$0.01474	
November	\$0.03320	\$0.02677	\$0.01316	
December	\$0.03512	\$0.02831	\$0.01392	

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, Voluntary Renewable*Connect Program Rider (Renewable*Connect Flex), and Voluntary Renewable*Connect Program Rider (Long Term) kWh sales. Qualifying costs are the sum of the following:

(Continued on Sheet No. 5-91.2)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401

MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FUEL CLAUSE RIDER (Continued)

Section No. 5
2nd Revised Sheet No. 91.4

EXCLUSION OF COMMUNITY SOLAR GARDEN COSTS

To comply with Minn. Stat. § 216B.1641, Subd. 11, the fuel adjustment charge to residential customers who have received bill payment assistance or income-qualified energy assistance programs within the proceeding twelve-month timeframe and who also do not subscribe to a community solar garden shall exclude the “net cost of community solar garden generation”. To achieve this exclusion, these customers shall receive a bill credit of \$0.00590 per kWh of billed usage that removes “net cost of community solar garden generation”.

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Date Filed: 07-30-25

By: Ryan J. Long

Effective Date:

EVP, Chief Legal & Compliance Officer and President, Northern States Power Company, a Minnesota corporation

Docket No. E002/AA-25-63

Order Date:

CERTIFICATE OF SERVICE

I, Joshua DePauw, 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-25-63**

Dated this 30th day of July 2025

/s/

Joshua DePauw
Regulatory Administrator

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
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4	Jessica L	Bayles	jessica.bayles@stoel.com	Stoel Rives LLP		1150 18th St NW Ste 325 Washington DC, 20036 United States	Electronic Service		No	AA-25-63
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6	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	AA-25-63
7	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		Yes	AA-25-63
8	James	Canaday	james.canaday@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota St. St. Paul MN, 55101 United States	Electronic Service		No	AA-25-63
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13	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
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16	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	AA-25-63
17	Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy		414 Nicollet Mall - 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63
18	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-Reliance Minneapolis MN, 55406 United States	Electronic Service		No	AA-25-63
19	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	AA-25-63
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23	Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY		401 Nicollet Mall FL 8 Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63
24	Shubha	Harris	shubha.m.harris@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401 - FL 8 Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63
25	Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall, 401-7 Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
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28	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	AA-25-63
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34	Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63
35	Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.		8300 Norman Center Drive Suite 1000 Bloomington MN, 55437 United States	Electronic Service		No	AA-25-63
36	Annie	Levenson Falk	annief@cupminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	AA-25-63
37	Ryan	Long	ryan.j.long@xcelenergy.com			414 Nicollet Mall 401 8th Floor Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63
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#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
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41	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	AA-25-63
42	Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis		350 S. 5th Street Room M 301 Minneapolis MN, 55415 United States	Electronic Service		No	AA-25-63
43	David	Moeller	dmoeller@allte.com	Minnesota Power			Electronic Service		No	AA-25-63
44	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63
45	Christa	Moseng	christa.moseng@state.mn.us		Office of Administrative Hearings	P.O. Box 64620 Saint Paul MN, 55164-0620 United States	Electronic Service		No	AA-25-63
46	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63
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48	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	AA-25-63
49	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	AA-25-63
50	Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy		414 Nicollet Mall FL 5 Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63
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#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
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53	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	AA-25-63
54	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall, MN1180-07-MCA Minneapolis MN, 55401-1993 United States	Electronic Service		Yes	AA-25-63
55	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN, 55423 United States	Electronic Service		No	AA-25-63
56	Joshua	Smith	joshua.smith@sierraclub.org			85 Second St FL 2 San Francisco CA, 94105 United States	Electronic Service		No	AA-25-63
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58	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	AA-25-63
59	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63
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61	James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63
62	Carla	Vita	carla.vita@state.mn.us	MN DEED		Great Northern Building 12th Floor 180 East Fifth Street St. Paul MN, 55101 United States	Electronic Service		No	AA-25-63
63	Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine		225 South Sixth Street, Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
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65	Patrick	Zomer	pat.zomer@lawmoss.com	Moss & Barnett PA		150 S 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63