COMMERCE DEPARTMENT

April 15, 2026 **PUBLIC DOCUMENT**

Sasha Bergman
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **PUBLIC** Comments of the Minnesota Department of Commerce
Docket No. E002/AA-24-63

Dear Ms. Bergman,

Attached are the **PUBLIC** comments of the Minnesota Department of Commerce (Department) in the following matter:

Annual True-Up Compliance Report of 2025 Annual Fuel Forecast and Monthly Fuel Cost Charges.

The Petition was filed by Northern States Power Company, doing business as Xcel Energy, on February 27, 2026, with Petition Errata filed on March 4, 2026.

The Department recommends the Minnesota Public Utilities Commission (Commission) approve the Petition with modifications, as described herein. The Department is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ Dr. SYDNIE LIEB
Assistant Commissioner of Regulatory Analysis

CN/AG/ad
Attachment

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

PUBLIC Comments of the Minnesota Department of Commerce

Docket No. E002/AA-24-63

I. INTRODUCTION

On February 27, 2026, Northern States Power Company, doing business as Xcel Energy (Xcel or the Company) filed its 2025 true-up Petition (Petition) in the current docket requesting the Minnesota Public Utilities Commission (Commission) authorize Xcel to implement true-up factors by class for the Company's Fuel Clause Adjustment (FCA).[1] On March 4, 2026, Xcel filed Errata stating that it had inadvertently omitted Part B, Attachment 16 from its initial filing and submitted that attachment with the errata. The added attachment addresses congestion and curtailment strategies compliance.[2]

As presented in the Petition, the actual 2025 fuel and purchased power costs were approximately $845.7 million compared to the approved 2025 forecast of $891.2 million, while actual collections were approximately $907.6 million because Minnesota jurisdictional sales were higher than forecasted. After accounting for a mid-year $10.4 million refund already implemented, Xcel reports a fuel-related over-collection of approximately $51.6 million.[3] The Company also proposes to refund approximately $83.1 million in 2025 nuclear production tax credits, credit about $0.2 million of land-sale gains, and offset those refunds by a roughly $3.1 million over-refund associated with the Sherco 3 replacement-power refund, for a net proposed refund of about $131.8 million.[4]

The Petition stated that Xcel would begin to implement the refund within 30 days if no party objected, in accordance with established FCA processes. As no party objected, Xcel therefore began the refund on April 1, 2026. The final amount of the refund may still be adjusted on September 1 once review of Xcel's petition is completed.[5]

Below, the Minnesota Department of Commerce (Department or DOC) provides relevant background information, summarizes the petition, and provides its analysis of Xcel's Petition.

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[1] *In the Matter of the Petition of Northern States Power Company for Approval of the 2025 Annual Fuel Forecast and Monthly Fuel Charges*, Petition, Xcel Energy, February 27, 2026, Docket No. E002/AA-24-63, (eDockets) 20262-228790-02 (Hereinafter "Current FCA True-Up Petition").

[2] *In the Matter of the Petition of Northern States Power Company for Approval of the 2025 Annual Fuel Forecast and Monthly Fuel Charges*, Errata, Xcel Energy, March 4, 2026, Docket No. E002/AA-24-63, (eDockets) 20263-228911-01

[3] A December 2025 mid-year adjustment filing by company already refunded $10.4 million in over-collected fuel costs to Xcel customers.

[4] FCA True-Up Petition at 1-2.

[5] FCA True-Up Petition at 3.

II. PROCEDURAL BACKGROUND

A. FUEL CLAUSE STATUTE

Minn. Stat. § 216B.16, subd. 7, the Fuel Clause Statute, authorizes the Commission to allow a public utility to automatically adjust charges for the cost of certain energy costs, referred to generally as "fuel." Specifically, the Fuel Clause Statute states:

> Notwithstanding any other provision of this chapter, the commission may permit a public utility to file rate schedules containing provisions for the automatic adjustment of charges for public utility service in direct relation to changes in:
>
> (1) federally regulated wholesale rates for energy delivered through interstate facilities;
> (2) direct costs for natural gas delivered;
> (3) costs for fuel used in generation of electricity or the manufacture of gas; or
> (4) prudent costs incurred by a public utility for sorbents, reagents, or chemicals used to control emissions from an electric generation facility, provided that these costs are not recovered elsewhere in rates. The utility must track and report annually the volumes and costs of sorbents, reagents, or chemicals using separate accounts by generating plant.

B. FUEL CLAUSE REFORM

On December 19, 2017, in Docket No. E999/CI-03-802, the Fuel Clause Investigation Docket, the Commission issued an Order[6] approving new annual fuel clause adjustment requirements as follows:

- The Commission will set recovery of the utility's fuel, power purchase agreements, and other related costs (fuel rates) in a rate case or an annual fuel clause adjustment filing unless a utility can show a significant unforeseen impact.
- Each electric utility will publish the monthly fuel rates in advance of each year to give customers notice of the next year's monthly electric fuel rates.
- The monthly fuel clause adjustment will not operate – each electric utility will charge an approved monthly rate.
- Utilities will be allowed to track any changes in $/MWh (megawatt-hour) fuel costs that occur over the year and there will be no carrying charge on the tracker.

[6] *In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments,* Order Approving New Annual Fuel Clause Adjustment Requirements and Setting Filing Requirements, Minnesota Public Utilities Commission, December 19, 2017, Docket No. E999/CI-03-802, (eDockets) 201712-138275-01.

- Annually, each electric utility will report actual $/MWh fuel costs in each month by fuel type (including identification of costs from specific power purchase agreements) and compare the annual revenue based on the fuel rates set by the Commission with annual revenues based on actual costs for the year.
- Each electric utility will refund any over-collections and show prudence of costs before allowing recovery of under-collections. If annual revenues collected ($/MWh) are higher than total actual costs, the utility must refund the over-collection through a true-up mechanism. If annual revenues collected are lower than total actual costs), the utility must show why it is reasonable to charge the higher costs (under-collections) to ratepayers through a true-up mechanism.
- Each utility must file proposed fuel rates outside of a general rate case. If the proposed fuel rates are different from the rates set in a utility's most recent miscellaneous rate docket that coincides with a rate case, the utility must fully explain the basis for any difference. These filings should include complete documentation supporting the proposed fuel rates, including each PPA, 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.
- Each utility must file a lessons-learned report at the end of three years to assess the new process.

On December 12, 2018, the Commission issued an Order[7] in the Fuel Clause Investigation Docket, ordering as follows:

- The implementation date for the new fuel clause adjustment process is January 1, 2020.
- Beginning January 1, 2020, until the end of the pilot or as otherwise ordered, the FCA process shall follow the calendar year, and **the annual fuel clause adjustment true-up compliance filings shall be filed by March 1 of the year following the relevant calendar year**.
- Monthly automatic adjustment filings shall be discontinued once the new fuel clause adjustment process is implemented.
- Each utility shall file its annual fuel clause adjustment report in a separate docket.
- All changes approved in this docket shall remain in effect indefinitely.

[7] *In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments,* Order Revising Implementation Date, Establishing Procedural Requirements, and Varying Rule, Minnesota Public Utilities Commission, December 12, 2018, Docket No. E999/CI-03-802, (eDockets) 201812-148414-01.

- Before the lessons-learned reports are filed three years after implementation of the new FCA process, parties will discuss what information will be included in those reports.

As explained in the December 12, 2018 Order, the FCA was previously adjusted monthly:

> Minn. Stat. § 216B.16, subd. 7, authorizes the Commission to allow a public utility to automatically adjust charges for the cost of fuel. Pursuant to this statute, Minnesota's rate-regulated electric utilities have automatically adjusted their rates monthly through a fuel clause adjustment (FCA) mechanism and subsequently filed monthly and annual reports, which the Commission has reviewed for accuracy and prudence. The adjustments have reflected, on a per-kilowatt-hour basis, deviations from the base cost of energy established in the utility's most recent general rate case.* In 2003, the Commission initiated an investigation to explore possible changes to the FCA, inviting stakeholders to comment on the purpose, structure, rationale, and relevance of the FCA.
> *Minn. R. 7825.2600.

The new process, as approved in the December 19, 2017 Order, moved to setting rates through an annual process with post-year true-ups:

> After multiple rounds of comments, including a reform proposal submitted by the Department, the Commission issued its Order Approving New Annual Fuel Clause Adjustment Requirements and Setting Filing Requirements (December 2017 Order), in which the Commission approved the Department's proposal to change the FCA process. Under the new process, each utility will forecast its monthly fuel costs for the upcoming year in an annual filing, and will charge those forecasted rates unless the utility can show a significant unforeseen impact on those rates during the forecasted year. At the end of the forecasted year, each utility will compare its forecasted rates with its actual fuel costs incurred throughout the year, and will refund any over collections and show prudence of costs before recovering under collections.

On June 12, 2019, the Commission issued an Order[8] in the Fuel Clause Investigation Docket with additional requirements, including:

- The Commission adopts the procedural schedule contained in Appendix A to this order.[9]

[8] *In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments,* Order Approving Additional Details of New Fuel Clause Adjustment Process, Minnesota Public Utilities Commission, June 12, 2019, Docket No. E999/CI-03-802, (eDockets) 20196-153514-01 (Hereinafter "June 2019 Fuel Clause Investigation Docket Order").
[9] In addition, the body of the Order states: "The filing schedule for the new FCA process was proposed in Section III of the joint comments and is contained in Appendix A to this order. The schedule covers the years 2020–2023, with 2020 acting as

- The Commission adopts a threshold of plus or minus 5 percent of all FCA costs and revenues to determine whether an event qualifies as a significant unforeseen impact that may justify an adjustment to the approved fuel rates. The Electric Utilities are permitted to implement revised rates following a 30-day notice period, subject to a full refund, if no party objects to the revised rates.
- The Commission approves the use of a regulatory asset account to track under-recovered FCA funds and a regulatory liability account to track over-recovered FCA funds. Regulatory assets and liabilities shall be recorded in FERC account 182.3.

The applicable parts of the procedural schedule[10] for the true-up as related to the Current FCA True-Up are below:

- March 1, 2026: Utilities Submit True-Up for 2025
- April 15, 2026: Initial Comments
- May 2, 2026: Utility Reply Comments
- May 15, 2026: Response by Consumer Advocates
- August 2, 2026: Commission Order on True-Up
- September 1, 2026: Implement True-Up

On August 15, 2023, Xcel filed its lessons-learned report regarding the Fuel Clause Adjustment (FCA) Reform mechanism.[11] On March 12, 2024, the Commission issued an Order[12] accepting Xcel's report and requiring Xcel to incorporate the following in future FCA filings:

- Answers to recurring information requests (IRs), including the most recent three-year average of actual annual data compared to forecast for the FCA calculation components, generation costs, purchase costs, inter-system sales and outages; and
- A comparison of the actual winter energy purchases to the forecast amounts, with an explanation of a variance of 5% or greater.

C. XCEL ANNUAL FCA HISTORY

Department Table 1 shows Xcel's approved forecasts, actual costs, and recoveries in each year under the annual (post-reform) FCA process.

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the transition year to the new FCA process and therefore using a slightly different schedule than the subsequent years. The schedule for the years after 2023 will continue following the same process as the 2021–2023 schedule."

[10] Modified from New FCA Procedural Schedule in June 2019 Fuel Clause Investigation Docket Order, Appendix A.

[11] *In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments,* Compliance Filing – Lessons-Learned Report, Xcel Energy, August 15, 2023, Docket No. E999/CI-03-802, (eDockets) 20238-198261-01.

[12] *In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments,* Order Approving Compliance Filings and Amending Initial Annual Filing Requirements, Minnesota Public Utilities Commission, March 12, 2024, Docket No. E999/CI-03-802, (eDockets) 20243-204248-01.

Department Table 1:
Xcel FCA Forecasted and Actual Costs: 2021-2025

Year	Docket	Total Cost		Unit Cost		Actual Recoveries	Over/(Under) Recovery
		Forecasted	Actual	Forecasted	Actual		
		$ millions		$/MWh		$ millions	
2021	20-417	749.7	894.1	27.78	31.71	812.3	(81.8)
2022	21-295	849.4	950.2	31.47	33.55	954	3.8
2023	22-179	1,069.2	935.3	38.96	33.44	1,061.3	126.0
2024	23-153	1,022.7	894.7	38.10	33.42	1,019.4	124.7
2025	24-63	891.2	845.7	33.27	30.97	907.6	62.0
2026	25-63	835.4	TBD	TBD	TBD	TBD	TBD

The Department summarizes each of these years below.

C.1. 2021 FCA (Docket No. E002/AA-20-417)

On May 1, 2020, Xcel filed its 2021 forecast petition, in Docket No. E002/AA-20-417.17 On December 22, 2020 the Commission issued an Order approving Xcel's 2021 forecast.[13] The approved forecasted FCA costs for 2021 were $749.7 million or $27.78/MWh. In addition, the December 22, 2020 Order required Xcel in its 2022 true-up filing and future filings, to identify the number and MWhs of planned outages that were originally classified as unplanned.

On August 27, 2021, Xcel filed a petition requesting to increase its monthly fuel rate for October through December 2021 for an unrecovered balance of $25.2 million.[14]

On September 24, 2021, the Department filed a letter supporting Xcel's proposal to recover $25.2 million.[15]

On March 1, 2022, Xcel submitted its 2021 true-up petition, requesting approval of 2021 actual FCA expenses of $894.1 million, $144.3 million higher than the approved forecast of $749.7 million.[16] On a unit cost basis, Xcel's requested 2021 actual FCA costs were $31.71/MWh versus $27.78/MWh

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[13] *In the Matter of the Petition of Northern States Power Company for Approval of the 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Order, Minnesota Public Utilities Commission, December 22, 2020, Docket No. E002/AA-20-417, (eDockets) 20205-162826-08.
[14] *In the Matter of the Petition of Northern States Power Company for Approval of the 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Compliance Filing – Rate Adjustment Proposal to Monthly Fuel Cost Charges for the 2021 Forecast Period, Xcel Energy, August 27, 2021, Docket No. E002/AA-20-417, (eDockets) 20218-177503-01.
[15] *In the Matter of the Petition of Northern States Power Company for Approval of the 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Letter, Minnesota Department of Commerce, September 24, 2021, Docket No. E002/AA-20-417, (eDockets) 20219-178245-01.
[16] *In the Matter of the Petition of Northern States Power Company for Approval of the 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Annual True-Up Compliance Report, Xcel Energy, March 1, 2022, Docket No. E002/AA-20-417, (eDockets) 20223-183343-01.

forecasted. Xcel collected $812.3 million in 2021 FCA revenues leading to a $81.8 million under-recovery.

On July 5, 2022, the Commission issued an Order approving Xcel's 2021 true-up.[17]

Xcel recovered $81.8 million through increased FCA charges over the 12 months beginning September 2022.[18]

C.2. 2022 FCA (Docket No. E002/AA-21-295)

On April 30, 2021, Xcel filed its 2022 forecast petition, in Docket No. E002/AA-21-295.[19] On December 2, 2021 the Commission issued an Order approving Xcel's 2022 forecast.[20] The approved forecasted FCA costs for 2022 were $849.4 million or $31.47/MWh. In addition, the Order required Xcel Energy, in its 2023 true-up filing, to identify the number and MWhs of planned outages that were originally classified as unplanned.

On May 19, 2022, Xcel made a compliance filing proposing to increase its monthly fuel forecast charges by $61 million for the second half of 2022.[21] The filing was unopposed. On June 27, 2022, Xcel submitted a compliance filing with the increased FCA rates as requested in the May 19, 2022 filing.[22]

On March 1, 2023, Xcel submitted its 2022 true-up petition, requesting approval of 2022 actual FCA expenses of $950.2 million, $100.8 million higher than the approved forecast of $849.4 million.[23] On a unit cost basis, Xcel's requested 2022 actual FCA costs were $33.55/MWh versus $31.47/MWh forecasted. Xcel collected $954.0 million in 2022 FCA revenues leading to a $3.8 million over-recovery.

On June 30, 2023, the Commission issued an Order approving Xcel's 2022 true-up.[24]

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[17] *In the Matter of the Petition of Northern States Power Company for Approval of the 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Order, Minnesota Public Utilities Commission, July 5, 2022, Docket No. E002/AA-20-417, (eDockets) 20227-187192-01.

[18] *In the Matter of the Petition of Northern States Power Company for Approval of the 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Compliance Filing, Xcel Energy, July 13, 2022, Docket No. E002/AA-20-417, (eDockets) 20227-187381-01.

[19] *In the Matter of the Petition of Northern States Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Petition, Xcel Energy, April 30, 2021, Docket No. E002/AA-21-295, (eDockets) 20214-173731-02.

[20] *In the Matter of the Petition of Northern States Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Order, Minnesota Public Utilities Commission, December 2, 2021, Docket No. E002/AA-21-295, (eDockets) 202112-180345-01.

[21] *In the Matter of the Petition of Northern States Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Compliance Filing – Rate Adjustment Proposal to Monthly Fuel Cost Charges for the 202Forecast Period, Xcel Energy, May 19, 2022, Docket No. E002/AA-21-295, (eDockets) 20225-185907-01.

[22] *In the Matter of the Petition of Northern States Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Compliance Filing, Xcel Energy, June 27, 2022, Docket No. E002/AA-21-295, (eDockets) 20226-186886-01.

[23] *In the Matter of the Petition of Northern States Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Annual True-Up Compliance Report, Xcel Energy, March 1, 2023, Docket No. E002/AA-21-295, (eDockets) 20233-193561-01.

[24] *In the Matter of the Petition of Northern States Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Order, Minnesota Public Utilities Commission, June 30, 2023, Docket No. E002/AA-21-295, (eDockets) 20236-197088-01.

Xcel refunded $3.8 million to ratepayers through a one-time decrease in FCA charges in September 2023.[25]

C.3. 2023 FCA (Docket No. E002/AA-22-179)

On May 2, 2022, Xcel filed its 2023 forecast petition, in Docket No. E002/AA-22-179.[26] On December 5, 2022 the Commission issued an order approving Xcel's 2023 forecast.[27] The approved forecasted FCA costs for 2023 were $1,069.2 million or $38.96/MWh.

On May 19, 2023, Xcel submitted a compliance filing proposing to reduce the 2023 forecast by $30 million.[28] Xcel also proposed reducing 2023 FCA rates to recover $10 million less in each of July, August, and September, to reflect this lower forecast. This update was de facto approved, as no party objected during the 30-day notice period established under the FCA process. Xcel submitted another rate adjustment proposal on November 21, 2023 to reduce FCA rates by $5 million per month from January-August 2024.[29] That proposal was likewise de facto approved.

On March 1, 2024, Xcel submitted its 2023 true-up petition proposing to refund an additional $126 million from April to December 2024, which Xcel implemented on April 1, 2024.[30]

On November 15, 2024, the Commission approved the undisputed, non-nuclear portions of the 2023 true-up and Xcel's proposed $126 million refund. The Commission also found that the Prairie Island outage resulted from Xcel's imprudence and concluded that additional record development was needed to determine the appropriate refund amount associated with outage-related replacement power costs and any claimed offsets. In addition, the Commission referred the disputed Prairie Island replacement power cost issue to the Court of Administrative Hearings for a contested case proceeding.[31]

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[25] *In the Matter of the Petition of Northern States Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Compliance Filing, Xcel Energy, July 10, 2023, Docket No. E002/AA-21-295, (eDockets) 20237-197344-01.

[26] *In the Matter of the Petition of Northern States Power Company for Approval of the 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Petition, Xcel Energy, May 5, 2022, Docket No. E002/AA-22-179, (eDockets) 20225-185476-01.

[27] *In the Matter of the Petition of Northern States Power Company for Approval of the 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Order, Minnesota Public Utilities Commission, December 5, 2022, Docket No. E002/AA-22-179, (eDockets) 202212-191109-01.

[28] *In the Matter of the Petition of Northern States Power Company for Approval of the 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Compliance Filing – Rate Adjustment Proposal to Monthly Fuel Cost Charges for the 2023 Forecast Period, Xcel Energy, May 19, 2023, Docket No. E002/AA-22-179, (eDockets) 20235-196011-01.

[29] *In the Matter of the Petition of Northern States Power Company for Approval of the 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Compliance Filing – Rate Adjustment Proposal to Monthly Fuel Cost Charges for the 2023 Forecast Period, Xcel Energy, November 21, 2023, Docket No. E002/AA-22-179, (eDockets) 202311-200652-02.

[30] *In the Matter of the Petition of Northern States Power Company for Approval of the 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Annual True-Up Compliance Filing, Xcel Energy, March 1, 2024, Docket No. E002/AA-22-179, (eDockets) 20243-204018-01.

[31] *In the Matter of the Petition of Northern States Power Company for Approval of the 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges*, Order, Minnesota Public Utilities Commission, November 15, 2024, Docket No. E002/AA-22-179, (eDockets) 202411-211999-01.

On March 11, 2026, the Administrative Law Judge issued Findings of Fact, Conclusions of Law, and Recommendation, recommending that Xcel refund $40.6 million plus interest and that Xcel not recover its litigation expenses from ratepayers.[32]

C.4. 2024 FCA (Docket No. E002/AA-23-153)

On May 1, 2023, Xcel filed its 2024 forecast petition, in Docket No. E002/AA-23-153.[33] On November 9, 2023, the Commission approved Xcel's 2024 forecast petition and revised adjustment factors as reflected in Xcel's October 23, 2023 filing, subject to true-up.[34] In addition, the Commission required Xcel to report in future FCA true-ups, on the:

- Assumed versus actual wind capacity factors for the true-up year and three prior years, with and without curtailment, for each Xcel-owned wind facility; and
- Prudency of its management of unplanned outages at Sherco 1, King, and Sherco 3 in Xcel's next FCA true-up petition.

On November 17, 2023, Xcel submitted a compliance filing with FCA rates to be implemented on January 1, 2024.[35]

On September 30, 2024, Xcel submitted a compliance filing proposing to refund ratepayers $30.5 million for over-collected fuel costs beginning November 1, 2024.[36] This update was de facto approved, as no party objected during the 30-day notice period established under the FCA process.

On March 3, 2025, Xcel submitted 2024 FCA true-up petition, proposing to refund to customers an additional $94 million in fuel cost over-collection, $176 million of nuclear production tax credit transactions, and $48 million related to Sherco Unit 3 outage replacement power costs, for a total proposed refund to customers of $318 million.[37]

On August 7, 2025, the Commission issued its Order in Docket No. E002/AA-23-153 accepting Xcel's 2024 Fuel Forecast True-Up Report, approving Xcel's proposed refund of $94 million for 2024 fuel cost over-recovery, and approving Xcel's proposed refund of $176 million for nuclear production tax credits.

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[32] *In the Matter of the Petition of Northern States Power Company for Approval of the 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges*, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION, Minnesota Court of Administrative Hearings, March 11, 2026, (eDockets) 20263-229130-01.

[33] In *the Matter of the Petition of Northern States Power Company for Approval of the 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Petition, Xcel Energy, May 1, 2023, Docket No. E002/AA-23-153, (eDockets) 20235-195484-01.

[34] *In the Matter of the Petition of Northern States Power Company for Approval of the 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Order, Minnesota Public Utilities Commission, November 9, 2023, Docket No. E002/AA-23-153, (eDockets) 202311-200373-01.

[35] *In the Matter of the Petition of Northern States Power Company for Approval of the 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Compliance Filing, Xcel Energy, November 17, 2023, Docket No. E002/AA-23-153, (eDockets) 202311-200577-01.

[36] *In the Matter of the Petition of Northern States Power Company for Approval of the 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Compliance Filing – Rate Adjustment Proposal to Monthly Fuel Cost Charges for the 2024 Forecast Period, Xcel Energy, September 30, 2024, Docket No. E002/AA-23-153, (eDockets) 20249-210591-01.

[37] *In the Matter of the Petition of Northern States Power Company for Approval of the 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Annual True-Up Compliance Filing, Xcel Energy, March 3, 2025, Docket No. E002/AA-23-153, (eDockets) 20253-215976-01, at 1 and 2.

The Commission also required Xcel, in its next fuel clause adjustment or true-up filing, to provide a narrative regarding whether the vendor of equipment related to the Prairie Island reactor coolant pump seal replacements accepted financial responsibility, how any vendor credits would offset ratepayer costs, and, if the vendor failed or refused to make Xcel and ratepayers whole, Xcel's assessment of the vendor's legal liability and actions taken in response. In addition, the Commission required Xcel to provide in its next annual filing: (1) ARR/FTR segment and strategy information, and (2) a detailed discussion of congestion and curtailment mitigation strategies, including cost-benefit analysis or justification for why such analysis could not be performed.[38]

C.5. 2025 FCA (Docket No. E002/AA-24-63) (Current Docket)

On May 1, 2024, Xcel filed its 2025 forecast Petition in Docket No. E002/AA-24-63.[39] On November 8, 2024, the Commission approved Xcel's 2025 forecast petition and revised adjustment factors, subject to true-up.[40]

On November 24, 2024, Xcel submitted a compliance filing with FCA rates to be implemented on January 1, 2025.[41]

On October 22, 2025, Xcel submitted a compliance filing proposing to refund ratepayers $40 million for over-collected fuel costs beginning December 1, 2025.[42] As no party objected during the 30-day notice period established under the FCA process, that update was implemented.

On February 27, 2026, Xcel submitted 2025 FCA true-up Petition, proposing to refund to customers an additional $51.6 million in fuel cost over-collection, and $83.1 million of nuclear production tax credit transactions. After accounting for the over-refund of $3.1 million for Sherco 3 replacement power costs refund and approximately $0.2 million related to land sale credits, Xcel proposed a total return of $131.8 million to customers.

III. SUMMARY OF THE TRUE-UP PETITION IN THE CURRENT DOCKET

At a high level, the 2025 true-up Petition shows a materially favorable fuel cost variance but a materially unfavorable MISO settlement variance. The largest cost reductions came from lower-than-forecast Community Solar Gardens (CSG) costs and lower-than-forecast company-owned natural gas generation costs. Those favorable variances were partly offset by significantly higher-than-forecast

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[38] *In the Matter of Xcel Energy's Petition for Approval of its 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Order, Minnesota Public Utilities Commission, August 7, 2025, Docket No. E002/AA-23-153, (eDockets) 20258-221852-01.
[39] In *the Matter of the Petition of Northern States Power Company for Approval of the 2025 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Petition, Xcel Energy, May 1, 2024, Docket No. E002/AA-24-63, (eDockets) 20245-206297-02.
[40] *In the Matter of the Petition of Northern States Power Company for Approval of the 2025 Annual Fuel Forecast and Monthly Fuel Cost Charges for the months of January - December 2025,* Order, Minnesota Public Utilities Commission, November 8, 2023, Docket No. E002/AA-24-63, (eDockets) 202411-211745-01.
[41] *In the Matter of the Petition of Northern States Power Company for Approval of the 2025 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Compliance Filing, Xcel Energy, November 24, 2024, Docket No. E002/AA-24-63, (eDockets) 202511-225258-01.
[42] *In the Matter of the Petition of Northern States Power Company for Approval of the 2025 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Compliance Filing – Rate Adjustment Proposal to Monthly Fuel Cost Charges for the 2025 Forecast Period, Xcel Energy, October 22, 2025, Docket No. E002/AA-24-63, (eDockets) 202510-224206-02.

MISO charges, especially incremental transmission losses and uplift-related charges, and by outage-driven market purchases.

Xcel's 2025 true-up Petition requests Commission approval of a net customer refund of approximately $131.8 million. The Petition attributes that result to lower-than-forecast fuel and purchased power costs, higher-than-forecast sales and collections, refund of 2025 nuclear PTCs, modest land sale credits, and an offsetting reduction associated with Sherco 3 replacement power refund over collection.

Under this proposal, the true-up filing will still be subject to the standard Commission review process approved in the FCA reform docket, with any revisions or updates to be implemented on September 1, 2026 following the Commission's August 2026 Order regarding the current Petition. Xcel would implement the proposed refund through the proposed tariff modification in Part A, Attachment 8 of the Petition. As noted above, Xcel provisionally implemented the refund starting on April 1, 2026 and will continue to refund through the rest of 2026.

A. FCA OVERVIEW

The Department summarizes Xcel's actual versus forecasted 2025 FCA costs and collections in the table below, which is reproduced from Table 1 in the current FCA True-up Petition.

Department Table 2:
Summary of Xcel's 2025 Minnesota FCA Costs and Collections[43]

	Actual	Forecast	$ Difference	% Difference
Total FCA Costs	$845,660,000	$891,200,000	$(45,540,000)	–5.1%
MWh Sales	27,308,156	26,788,077	520,079	1.9%
Cost/MWh	$30.97	$33.27	$(2.30)	–6.9%
Fuel Collections	$907,646,000	$891,200,000	$16,446,000	1.8%
Mid-Year Adjustment Refund	$(10,367,000)			
(Over) Under-Recovery	$(51,619,000)			
Nuclear PTC Credits	$(83,059,000)			
Land Sales Credits	$(199,000)			
Sherco 3 Over-Refund	$3,105,000			
Total (Over) Under-Recovery	$(131,772,000)			

B. MAJOR CATEGORIES

The cost and offsetting credit/revenue components of the Company's actual and forecasted fuel and purchased power costs recoverable through the FCA can be broken into several major categories, as summarized in the following table.

[43] Figures from the Current FCA True-Up Petition at 4, Table 1

Department Table 3
Xcel's Actual vs. Forecasted 2025 FCA Costs and Revenues – Major Categories ($000)

		Actuals[44]	Forecast[45]	$ Variance	% Variance
1a	Coal	$151,924	$158,986	($7,062)	-4.4%
1b	Wood/RDF	$8,336	$9,594	($1,258)	-13.1%
1c	Natural Gas CC	$119,128	$215,885	($96,757)	-44.8%
1d	Natural Gas & Oil CT	$53,209	$45,276	$7,933	17.5%
1e	Nuclear	$113,877	$121,629	($7,752)	-6.4%
1 = ∑(1a-1e)	**Xcel's Generating Stations**	**$446,473**	**$551,370**	**($104,896)**	**-19.0%**
2a	LT Purchased Energy (Gas)	$136,512	$138,137	($1,625)	-1.2%
2b	LT Purchased Energy (Solar)	$52,112	$55,498	($3,386)	-6.1%
2c	LT Purchased Energy (Wind)	$212,239	$217,934	($5,695)	-2.6%
2d	LT Purchased Energy (Other)	$76,474	$64,448	$12,026	18.7%
2 = ∑(2a-2d)	**LT Purchased Energy**	**$477,337**	**$476,017**	**$1,320**	**0.3%**
3	Comm. Solar Gardens (CSG)	$205,484	$264,458	($58,974)	-22.3%
4	ST Market Purchases	$124,808	$16,552	$108,256	654.0%
5	MISO Costs	$187,110	$163,676	$23,434	14.3%
6= ∑(1-5)	**Total System Costs**	**$1,441,212**	**$1,472,073**	**($30,860)**	**-2.1%**
7	Sales Revenues	($307,174)	($256,708)	($50,466)	19.7%
8	CSG-Above Market Costs	($134,517)	($184,921)	$50,405	-27.3%
9	Renewable*Connect	($23,717)	($45,947)	$22,230	-48.4%
10 = ∑(6-9)	**Net System FCA Costs**	**$975,805**	**$984,497**	**($8,692)**	**-0.9%**
11	MN Juris. Sales MWh	28,316,612	28,093,335	223,277	0.8%
12	RC & Windsource MWh	-1,008,456	-1,305,258	296,802	-22.7%
13 = ∑(11-12)	**Net MN Sales MWh**	**27,308,156**	**26,788,077**	**520,079**	**1.9%**
14	MN FCA Costs	$698,112	$697,792	320	0.0%
15	CSG-Above Mkt. Costs	$134,439	$184,921	($50,483)	-27.3%
16	Biomass Buyouts	$8,487	$8,487	$0	0.0%
17	Net CSG Cost Exclusion	$2,246	$ -	$2,246	N/A
18	SES Exemption	$1,937	$ -	$1,937	N/A
19	Land Sale Credits	$199	$ -	$199	N/A
20	Nuclear PTCs	($83,059)	$ -	($83,059)	N/A
21 = ∑(14-20)	**Net MN FCA Costs**	**$762,361**	**$891,200**	**($128,839)**	**-14.5%**
22 = 21÷13	**Net MN FCA Costs ($/MWh)**	**$27.92**	**$33.27**	**($5.35)**	**-16.1%**

In explaining the results shown in the table above, Xcel points to a significantly favorable fuel-cost variance but a substantially unfavorable MISO settlement variance. The largest cost reductions stemmed from lower-than-forecast Community Solar Gardens (CSG) costs and lower-than-forecast company-owned natural gas generation costs. Those favorable variances were partly offset by

[44] Current FCA True-Up Petition, Part A, Attachments 1 and 2.
[45] *In the Matter of the Petition of Northern States Power Company for Approval of the 2025 Annual Fuel Forecast and Monthly Fuel Charges*, Reply Comments-Correction, Xcel Energy, August 7, 2024, Docket No. E002/AA-24-63, (eDockets) 20248-209337-01, Part A, Attachment 1.

significantly higher-than-forecast MISO charges, especially incremental transmission losses and uplift-related charges, and by outage-driven market purchases.[46]

IV. DEPARTMENT ANALYSIS

The Department analyzes Xcel's true-up petition and reviews individual components of Xcel's actual 2025 FCA costs below.

A. NATURAL GAS

Xcel's actual costs for owned natural gas generation were $172.34 million, 34% ($88.83 million) lower than forecasted. Actual generation from owned natural gas was 5,033 GWh, 33.74% lower than forecasted, with the lower-than-forecasted owned gas generation costs attributable to actual unit costs of $23.14/MWh being 32.9% lower than forecasted. Xcel attributed much of this shortfall to the Riverside generator failure and to a longer-than-assumed outage at Black Dog. Because owned natural gas generation was materially below forecast, fuel expenses decreased significantly.[47]

Xcel's actual costs for purchased natural gas generation (gas PPAs) were $136.5 million, 1.2% ($1.6 million), slightly lower than forecasted. Actual generation from gas PPAs was 3,855 GWh, 12.4% lower than forecasted, with almost in-line gas PPA costs attributable to actual unit costs of $35.41/MWh being 12.8% higher than forecasted.[48]

The Department concludes Xcel has reasonably explained the variances between actual and forecasted natural gas costs. The Department also continues to note the extremely significant impact of gas prices on the electricity market, not only due to their direct effect on the cost of gas generation, but also their knock-on effects due to gas generation's strong impact on setting LMPs. However, the prudence of the outage-related replacement power costs that partially offset these lower fuel costs cannot be fully resolved solely by looking at the natural-gas line item. The Department addresses outage prudence separately below.

B. COMMUNITY SOLAR GARDENS (CSG)

Actual 2025 CSG costs were $205.5 million, or $59.0 million (22.3%) lower than forecasted. Actual unit costs were $127.87/MWh, or $3.77/MWh (3.04%) lower than forecasted. The primary reason for lower-than-forecasted CSG costs was actual generation of 1,607 GWh being 524 GWh (24.59%) lower than forecasted.[49] In response to DOC IR No. 42, Xcel further explained that actual 2025 CSG generation was 524 GWh below forecast because approximately 23% of the shortfall was due to lower-than-expected solar output, 46% was due to fewer MW being placed into production than forecast, and 31% was due to lower MWh per MW than forecast.[50] Xcel also provided additional information on CSGs in Part C, Attachments 8-10.

[46] Current FCA True-Up Petition at 4 and 5.
[47] Current FCA True-Up Petition at 9 and 10.
[48] Current FCA True-Up Petition at 11.
[49] Current FCA True-Up Petition at 12.
[50] Xcel's response to DOC IR No.42, see Attachment 1.

The Department concludes Xcel has reasonably explained the variances between actual and forecasted CSG costs and does not have any objections to Xcel's proposed actual 2025 CSG recoveries.

C. COAL

Actual 2025 Company-owned coal generation costs were $151.9 million, $7.1 million (4.44%) lower than forecasted. Actual unit costs were $25.21/MWh, or $1.28/MWh (4.83%) lower than forecasted. Xcel attributed the lower-than-forecasted unit costs to lower realized coal and rail costs.[51]

The Department concludes Xcel has reasonably explained the variances between actual and forecasted coal costs. The Department does not have any objections to Xcel's proposed actual 2025 coal recoveries and will further discuss the outages referenced in this section below.

D. NUCLEAR

D.1. Nuclear outages

Actual 2025 Company-owned nuclear generation costs, excluding outage costs, were $113.9 million, $7.8 million (6.37%) lower than forecasted. The variance was primarily attributable to Monticello's refueling outage, which was longer than forecast.[52]

In August 7, 2025 Order in Docket No. E002/AA-23-153, the Commission required Xcel, in its next fuel clause adjustment or true-up filing, to provide a narrative regarding whether the vendor of equipment related to the Prairie Island reactor coolant pump seal replacements accepted financial responsibility, how any vendor credits would offset ratepayer costs, and, if the vendor failed or refused to make Xcel and ratepayers whole, Xcel's assessment of the vendor's legal liability and actions taken in response. The Company included a Prairie Island Unit 1 vendor liability update regarding the reactor coolant pump seal replacement issue, including discussion of additional maintenance, vendor responsibility, settlement, and credit treatment. Xcel reports that vendor liability reduced customer costs through a $616,022 vendor-covered second mobilization and replacement and a $100,000 credit applied to Prairie Island Unit 2's refueling outage.[53] Additionally, the Company agreed to pay $639,202 for the first mobilization and replacement. The Company noted these credits were applied to the Fall 2024 refueling outage for Prairie Island Unit 1 and the Fall 2025 refueling outage for Prairie Island Unit 2, and reduced the costs customers would pay through base rates.

[51] Current FCA True-Up Petition at 8.
[52] Current FCA True-Up Petition at 10, 11.
[53] Current FCA True-Up Petition at 22, 23.

Based on the Department's review of Xcel's reporting and resulting information provided in the Petition, the Department does not object to Xcel's explanation of the 2025 nuclear variance and concludes that Xcel has complied with the additional Prairie Island vendor liability reporting requirement established in Docket No. E002/AA-23-153. The Department requests Xcel to address in Reply Comments where these credits were reflected in base rates, including references to the relevant schedules or workpapers in Docket No. E002/GR-24-320.

D.2. Nuclear Production Tax Credits

The 2022 Inflation Reduction Act (IRA) extended and expanded production tax credits (PTCs) and investment tax credits (ITCs) benefits for clean energy resources and created a new PTC for nuclear resources. Beginning in 2024, "nuclear facilities are eligible for base credits of 0.3 cents/kWh generated by existing facilities" up to 1.5 cents/kWh if certain requirements are met. Xcel proposes returning $83.1 million in credits to customers, less transaction costs, in 2025. The Company explains NPTCs in 2025 were significantly lower than in 2024 ($175.8 million) due to higher annual gross receipts in 2025.[54]

Part A, Attachment 9 of the Petition includes a tracker for the PTCs and supporting calculations. The Department reviewed the calculations provided by the Company and supports refunding $83.1 million in nuclear PTCs.

E. NON-NUCLEAR GENERATION OUTAGES

Part C, Attachment 3 of the Petition provides a narrative regarding plant operation and maintenance contractor performance and operational initiatives. Part C, Attachment 4 provides the following information for each unplanned (forced) outage: primary reason, start and end date, equipment causing the outage, description of equipment failure, change in energy costs, and steps taken to prevent reoccurrence. Part C, Attachment 5a, provides actual versus forecasted unplanned outage costs and MWhs. Part C, Attachment 5b, provides actual versus forecasted planned outage costs and MWh. In addition, Part C, Attachments 5c and 5d, provide 3-year comparisons of forecasted outage costs to actuals for unplanned and planned outages, respectively.

E.1. Non-Nuclear Unplanned Outages

The Department summarizes Xcel's 2025 actual versus forecasted unplanned outages for non-nuclear units below:

[54] Current FCA True-Up Petition at 17, 18.

Department Table 4:
Xcel 2025 Non-Nuclear Unplanned Outages[55]

Unit	Type of Plant	Fuel	Expected Retirement	Actual MWh	Forecasted MWh	Difference
Black Dog	CT*, CC^	Natural Gas		**[TRADE SECRET DATA HAS BEEN EXCISED]**		
High Bridge 1						
High Bridge 2	CC		TBD			
Riverside 1						
Riverside 2						
Natural Gas Subtotal						
King 1			2028			
Sherco 1	Steam	Coal	2026			
Sherco 3			2030			
Coal Subtotal						
Total						

*CT = Combustion Turbine
^CC = Combined Cycle

As noted above, the November 9, 2023 Order in Docket No. E002/AA-23-153 requires Xcel to report the following in future FCA true-ups: prudency of its management of unplanned outages at Sherco 1, King, and Sherco 3 in Xcel's next FCA true-up petition. Xcel provided information related to this requirement in Part C, Attachment 3, page 3. As shown in the table above, these facilities are expected to shut down in the near- to medium-term.

Unplanned outages at both Xcel's' coal and natural gas units were **[TRADE SECRET DATA HAS BEEN EXCISED]**. As noted above, Xcel reports on each unplanned (forced) outage in Part C, Attachment 4.

On the present record, the Department does not object to Xcel's general explanation of several ordinary forced outages reflected in Part C, Attachment 4a. For a number of units, Xcel identified discrete equipment failures, described repair work, and identified corrective actions intended to prevent recurrence. The Department is more concerned, however, with Xcel's responses regarding Sherco Unit 1 and Riverside.

E.1.1. Sherco Unit 1 Outage

With respect to Sherco Unit 1, Xcel stated that, because Sherco Unit 1 is scheduled to retire on December 31, 2026, certain maintenance and inspection work was not performed during the 2024 outage with the understanding that there would be an increased risk of future failures, including boiler

[55] Figures from Current FCA True-Up Petition, Part C, Attachment 5a

tube leaks, and that "managed decline" resulted in acceptance of additional risk for certain scrubber-module derates.[56]

In response to DOC IR No. 53, Xcel further explained that, as assets near retirement, the Company reduces capital and O&M spending and must balance the cost to customers of additional expenditures on incremental improvements to unit performance against the potential for some additional outages and increased purchased power expense.[57] On this record, largely due to the expected December 31, 2026 retirement date, the Department finds Xcel's explanation reasonable. The Department continues to note the inherent tension in the managed decline strategy but does not object to Xcel's explanation of Sherco Unit 1 outage management in this docket.

E.1.2. Riverside Outage

Riverside presents the most significant outage issue in the current True-up Petition. Xcel reports that Riverside suffered a catastrophic generator failure in April 2025 after liberation of a retaining ring caused extensive damage to the generator field and stator. Xcel further reports that no viable used replacement unit was available, so the OEM developed a repair-based recovery approach, and long-lead material procurement has extended the outage duration. Xcel now expects Riverside to return to service **[TRADE SECRET DATA HAS BEEN EXCISED]**.[58] Xcel is also pursuing an insurance claim and is continuing to assess whether it will file any additional third-party claims. The Company states that its estimate of 2025 Riverside replacement power costs is a high-level, simplified estimate that remains subject to refinement.[59]

In response to DOC IR No. 47, Xcel explained it cannot identify Riverside-related FCA costs directly from invoices paid and instead must estimate those costs through production cost modeling or another replacement power cost methodology. Xcel's rough incremental fuel costs for the Riverside outage in 2025 are estimated at **[TRADE SECRET DATA HAS BEEN EXCISED]**. Xcel also stated it could maintain the Riverside-related FCA amount in a deferred account if recovery is delayed.[60] In addition, the insurance record is still undeveloped. In response to DOC IR No. 54, Xcel stated that the Riverside claim adjustment is in the early stages, temporary repairs may fall under extra-expense coverage, and both the accounting treatment of any insurance proceeds and the mechanism by which customers would receive the benefit of any such proceeds remain unknown.[61]

Taken together, these facts distinguish Riverside from the ordinary forced outage events in this filing. The amount at issue for this outage is substantial (for 2025 and 2026 (annualized 2025 amount) the Department estimates **[TRADE SECRET DATA HAS BEEN EXCISED]** for replacement power costs), the outage extends beyond the current reporting year, the claimed replacement power costs are high-level estimated, and insurance and any other third-party recovery remain unresolved.

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[56] Xcel's response to DOC IR No. 48, see Attachment 2
[57] Xcel's response to DOC IR No. 53, see Attachment 3.
[58] Current True-up Petition at 19.
[59] Current TCA True-Up Petition, at 18, 19.
[60] Xcel's response to DOC IR No. 47, see Attachment 4.
[61] Xcel's response to DOC IR No. 54, see Attachment 5.

Because the present record is not sufficiently developed to determine the prudence and net customer impact of the Riverside outage, the Department recommends that the Commission reserve the determination of prudence and recovery of Riverside-related replacement power costs and refer the Riverside issue to a contested case, where the record can be fully developed, including through engineering analysis. The contested case record should address whether Xcel prudently incurred Riverside-related replacement power costs, including engineering causation, outage management, the reasonableness of the Company's replacement power cost estimate, and the extent to which insurance or third-party recoveries reduce the net amount properly borne by customers. The Department made a similar recommendation in Xcel's current pending rate case in Docket E002/GR-24-320[62] regarding the Riverside outage, although the rate case was focused on rate case type costs and revenues and not on replacement power costs in this proceeding.

E.2. Planned Outages

The Department summarizes Xcel's 2025 actual versus forecasted planned outages for non-nuclear units below:

Department Table 5:
Xcel 2025 Non-Nuclear Planned Outages[63]

Unit	Type of Plant	Fuel	Expected Retirement	Actual MWh	Forecasted MWh	Difference
Black Dog	CT*, CC^	Natural Gas		**[TRADE SECRET DATA HAS BEEN EXCISED]**		
High Bridge 1						
High Bridge 2	CC		TBD			
Riverside 1						
Riverside 2						
Natural Gas Subtotal						
King 1			2028			
Sherco 1	Steam	Coal	2026			
Sherco 3			2030			
Coal Subtotal						
Total						

*CT = Combustion Turbine
^CC = Combined Cycle

Planned outages were **[TRADE SECRET DATA HAS BEEN EXCISED]** than forecasted. The Department reviewed the information provided by the Company in Part C, Attachment 4b of its Petition, including the outage category, primary reason for the outage, start and end dates, duration, description of actions taken during the outage, and change in energy costs due to the outage. Although actual 2025 non-nuclear planned outages differed from forecast, the Department did not identify objections based on its review of the outage-specific information provided.

[62] Surrebuttal Testimony of Department witness Mark Johnson page 25 to 30.
[63] Figures from current FCA True-Up Petition, Part C, Attachment 5b.

In response to DOC IR No. 44, Xcel stated that King Unit 1 was the only 2025 planned outage extension in NSP and that the extension included 16 days attributable to turbine-valve work and 30 days attributable to vendor rework, totaling 46 days and approximately $9.9 million in incremental energy cost.[64] In response to DOC IR No. 45, Xcel further stated that the generator rework involved a preventable vendor execution error associated with the incorrect installation of generator couplings and rotor alignment and attributed 30 outage days to that event.[65] Xcel further explained that it provided substantial oversight of Siemens Energy's work, recovered approximately $1.5 million of repair costs from Siemens under the warranty, and contends that customers should still bear the outage-related replacement power costs because Xcel's vendor selection and oversight were reasonable under the circumstances.[66]

Regarding King Unit 1 outage, the Department does not consider Xcel's explanation unreasonable. However, because Xcel states that it recovered approximately $1.5 million from Siemens, the Department requests that Xcel explain in its Reply Comments whether that warranty recovery has already been flowed back to customers, and if so, where that treatment is reflected. If the warranty recovery has not yet been flowed back, Xcel should explain how and when customers will receive the benefit of that amount.

E.3. Outages and Maintenance

In addition to reviewing Xcel's outage information on a stand-alone basis, the Department reviewed Xcel's generation maintenance expenses in relation to forced outage costs, as discussed below.

Because (1) the amount of generation maintenance expense is linked to a utility's unplanned outages, (2) utilities have an incentive to minimize generation maintenance expense between rate cases, and (3) utilities do not have a strong incentive to minimize the replacement power costs for which they receive flow through recovery. The Department monitors the difference between investor-owned utilities' actual and approved generation maintenance expenses in FCA true-up filings. As part of this review, Xcel is required to include in FCA filings the actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the utility's most recent rate case.[67] Xcel's true-up petition provides this information in Part C, Attachment 6.

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[64] Xcel's response to DOC IR No. 44, see Attachment 6.
[65] Xcel's response to DOC IR No. 45, see Attachment 7.
[66] Xcel's response to DOC IR No. 52, see Attachment 8.
[67] *In the Matter of the Review of the 2006 Annual Automatic Adjustment of Charges for All Electric and Gas Utilities*, Order, Minnesota Public Utilities Commission, February 6, 2008, Docket No. E999/AA-06-1208, (eDockets) 4928266 (Hereinafter "06-1208 Order"). This requirement stems from the drastic increase in IOUs' outage costs during FYE06 and FYE07. When a plant experiences a forced outage, the utility must replace the megawatt hours that plant would have produced if it had been operating, usually through wholesale market purchases. The cost of those market purchases flows through the FCA directly to ratepayers. The high level of outage costs in FYE06 and FYE07 raised the issues of whether plants were being maintained appropriately to prevent forced (unplanned) outages, and whether IOUs were spending as much on plant maintenance as they were charging to their customers in base rates. The Commission agreed with the Department and the Large Power Intervenors that "utilities have a duty to minimize unplanned facility outages through adequate maintenance

For the 2024 test year, Xcel's approved Minnesota generation maintenance expense in base rates was $136.2 million, or $16.0 million higher than the 2025 actual generation maintenance expense of $120.3 million.[68] The Department noted its concern in prior year FCA True-Up comments that Xcel was not spending the amount of maintenance expense being recovered from ratepayers in base rates.[69] The Department continues to strongly encourage Xcel to fully spend the amount of maintenance expense being recovered from rate payers in base rates and will continue to monitor, in future FCA true-up filings, under-spending of maintenance expense provided in base rates, especially as it relates to forced plant outages.

E.4. Non-Nuclear Outages Conclusion

Based on the Department's review of Xcel's reporting and the resulting information provided in the petition, the Department does not object to Xcel's general explanation of a number of ordinary 2025 forced and planned outage events. However, the Department is not prepared to recommend approval of the recovery of Riverside-related outage replacement power costs on the current record.

For the King Unit 1 outage, the Department requests that Xcel explain in its Reply Comments whether the $1.5 million warranty recovery has already been flowed back to customers, and if so, where that treatment is reflected. If the warranty recovery has not yet been flowed back, Xcel should explain how and when customers will receive the benefit of that amount.

For the Riverside outage, the Department recommends that the Commission reserve the determination of prudence and recovery of Riverside-related replacement power costs and refer the Riverside issue to a contested case, where the record can be fully developed, including through engineering analysis. The contested case record should address whether Xcel prudently incurred Riverside-related replacement power costs, including engineering causation, outage management, the reasonableness of the Company's replacement power cost estimate, and the extent to which insurance or third-party recoveries reduce the net amount properly borne by customers. The Department made a similar recommendation in Xcel's current pending rate case in Docket E002/GR-24-320 regarding the Riverside outage.[70] Although the rate case was focused on rate case type costs and revenues and not on replacement power costs in this proceeding.

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and to minimize the costs of scheduled outages through careful planning, prudent timing, and efficient completion of scheduled work." 06-1208 Order at 5.

[68] Current FCA True-Up Petition, Part C, Attachment 6.

[69] *In the Matter of the Petition of Northern States Power Company for Approval of the 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Comments, Minnesota Department of Commerce, April 15, 2024, Docket No. E002/AA-22-179, (eDockets) 20244-205419-01 at 16-17 (Hereinafter "2023 FCA True-Up Department Comments").

[70] Surrebuttal Testimony of Department witness Mark Johnson, pages 25 to 30.

F. CONGESTION

The true-up Petition provides information on congestion and other MISO market costs on pages 4-5, and 14-15, and in Part B (in particular Part B, Attachment 1 and Attachment 2, page 13). The Petition also provides information on curtailment, which occurs due to congestion, in Part C, Attachments 1-2.

Actual congestion costs of $225.8 million for 2025 were about the same as the $226.3 million forecast, though higher than the 2024 congestion costs of $174 million. Actual revenues from FTRs of $118.8 million, which is $41 million (52.8%) higher than forecast, help significantly reduce the net congestion cost.

In the August 7, 2025, Order in Docket No. E002/AA-23-153, the Commission required Xcel, in its next FCA or true-up filing, to provide additional information regarding ARR/FTR segment and strategy information and congestion and curtailment mitigation strategies (Order points 5 and 6).[71] In the current True-up Petition, Xcel provided that information in Part B, Attachments 15 and 16, with Attachment 16 supplied through the March 4, 2026 Errata filing. The Department reviewed the attachments and concluded that Xcel complies with the filing requirement.

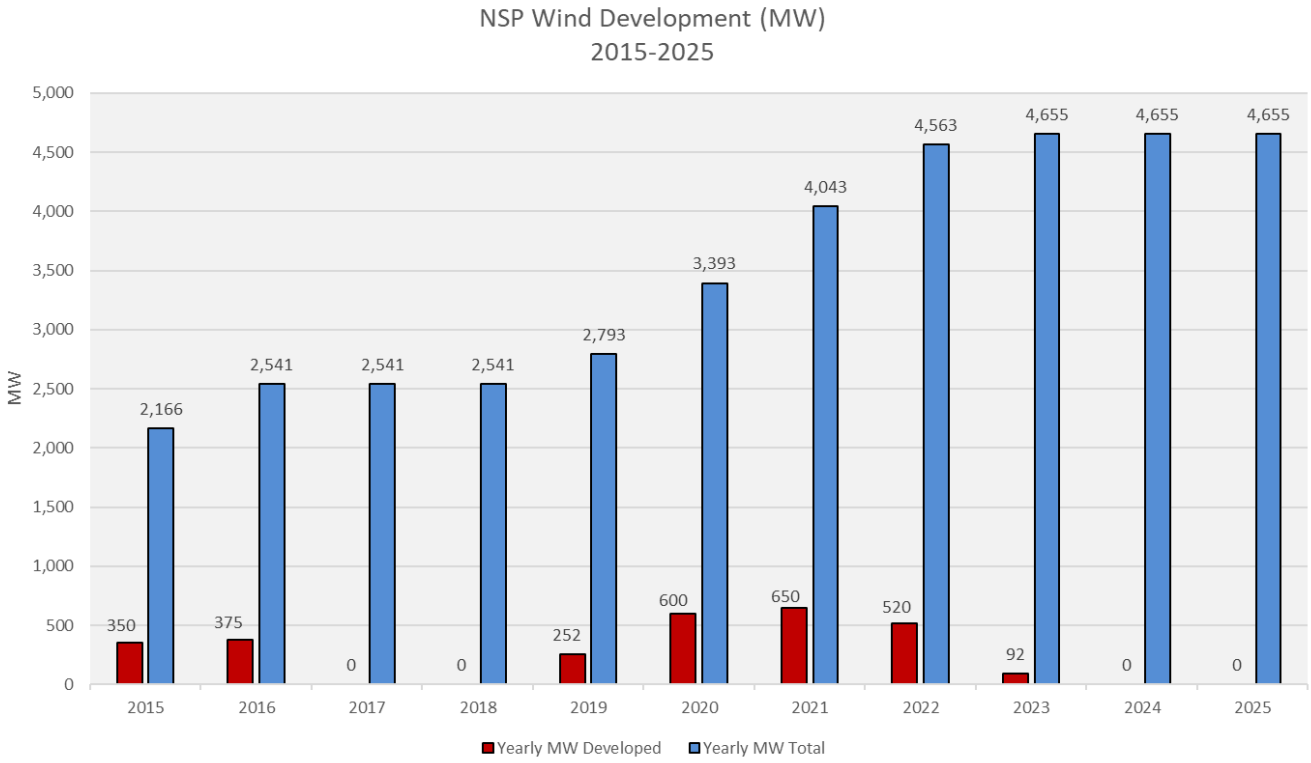
The Department concludes Xcel has reasonably explained the variance between actual and forecasted 2025 congestion costs. The Department does not have any objections to Xcel's proposed actual 2025 congestion cost recovery.

G. WIND

G.1. Overview

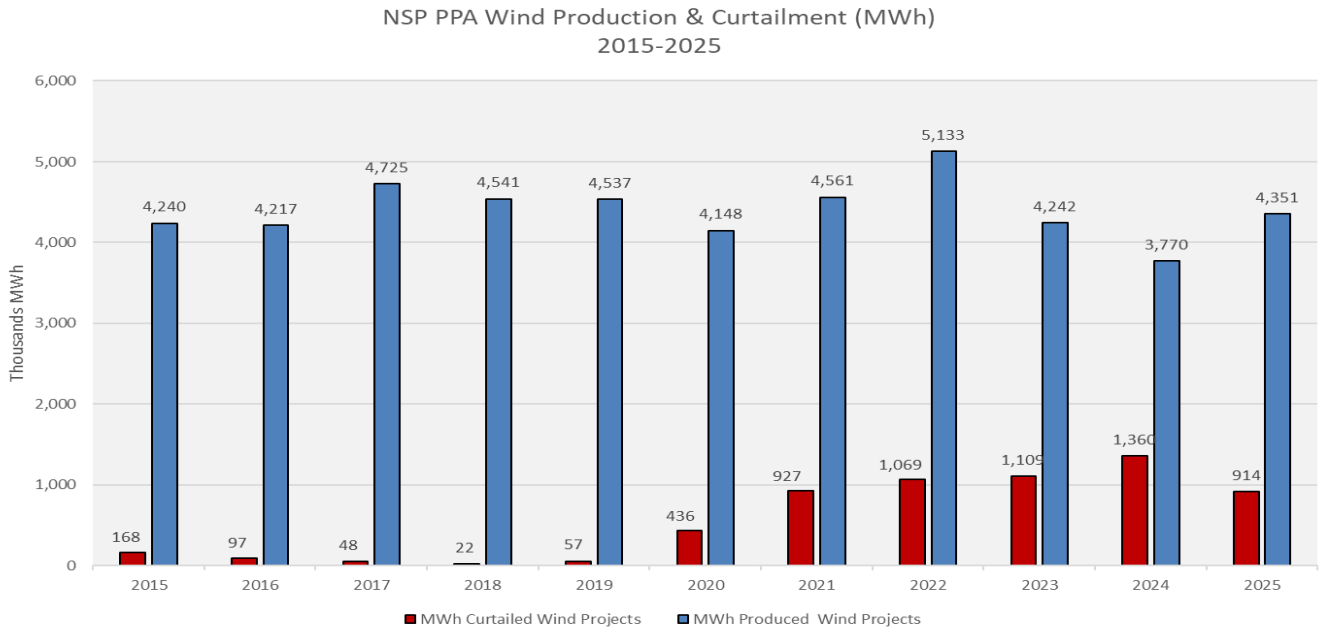
Prior to 2024, Xcel added significant wind capacity, as shown in Chart 1 provided by the Company in Part C, Attachment 1 of the current FCA True-up Petition,[72] which the Department reproduces below. As noted in the Petition, this chart shows planned and installed Company-owned and PPA wind generation facilities on an incremental and cumulative basis.

[71] *In the Matter of Xcel Energy's Petition for Approval of its 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Order, Minnesota Public Utilities Commission, August 7, 2025, Docket No. E002/AA-23-153, (eDockets) 20258-221852-01.
[72] Current FCA True-Up Petition, Part C, Attachment 1 at 17.



G.2. Wind PPAs

Xcel provided Company-total wind production and curtailment from PPAs in Chart 2 provided by the Company in Part C, Attachment 1 of its filing,[73] which the Department reproduces below.

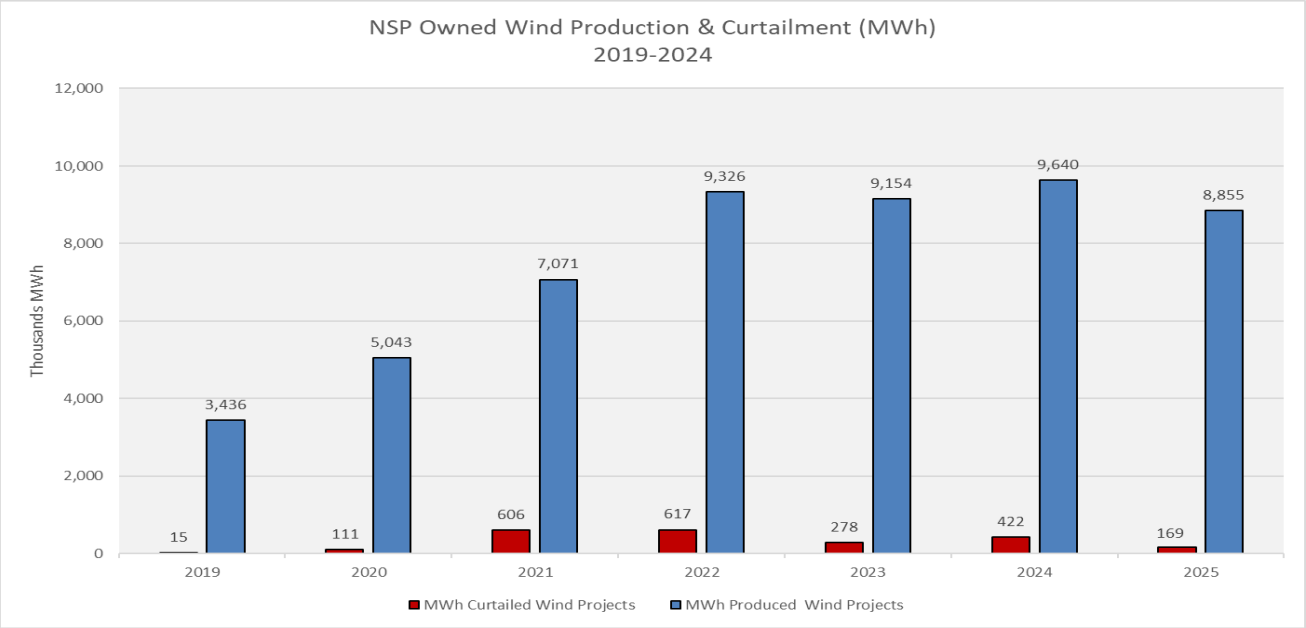


[73] Current FCA True-Up Petition, Part C, Attachment 1 at 18.

As shown in the figure above, wind PPA curtailment increased somewhat year-over-year until 2024 and reduced in 2025, but production remained stable, roughly in line with prior years since 2015.

G.3. Xcel-Owned Wind

The Company provided Chart 3 in Part C, Attachment 1 of its filing[74] reproduced below, showing production and curtailment of Xcel-owned wind projects. The Chart shows curtailment decreased significantly from last year while wind projects are also reduced.



When Company-owned wind projects are approved, typically Xcel assumed certain average production levels over the life of the facilities, relative to the overall production capacity. The result is an assumed capacity factor. Since the net economic benefit of wind farms hinges on the amount of energy produced, whether ratepayers in fact benefit from the initial capital costs likewise hinges in large part on the actual capacity factors.

On November 9, 2023, the Commission issued an Order in Docket No. E002/AA-23-153, approving Xcel's 2024 FCA forecast. The November 9, 2023 Order also required Xcel to provide in future FCA true-up reports, for each Xcel-owned wind facility, the assumed versus actual capacity factors for the true-up year and three prior years, both after curtailment and if no curtailment had occurred.[75] Xcel's true-up petition provide this information in Part C, Attachment 2b. The Department summarizes the information below.

[74] *Id.*

[75] *In the Matter of the Petition of Northern States Power Company for Approval of the 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges,* Order, Minnesota Public Utilities Commission, November 9, 2023, Docket No. E002/AA-23-153, (eDockets) 202311-200373-01 at Order Point 5.

Department Table 6:
Actual vs. Xcel Forecasted Capacity Factors at Xcel-Owned Facilities[76]

Wind Farm Name	Assumed at Acquisition	Actual Generation						Actual Generation + Curtailment Estimate					
		2022	2023	2024	2025	Avg.	%Assumed	2022	2023	2024	2025	Avg.	%Assumed.
Blazing Star 1	[TRADE SECRET DATA HAS BEEN EXCISED]	52.2	46.1	46.5	49.8	48.7	[TRADE SECRET DATA HAS BEEN EXCISED]	52.6	46.5	47.6	50.1	49.2	[TRADE SECRET DATA HAS BEEN EXCISED]
Blazing Star 2		51.1	46.6	47.3	49.5	48.6		51.7	46.9	48.1	49.6	49.1	
Borders		50.6	44.4	47.3	29.5	43.0		51.4	44.7	48.2	30.2	43.6	
Comm. Wind N.		52.4	47.3	49.5	47.7	49.2		52.4	47.3	49.6	47.7	49.3	
Courtenay		46.6	39.6	42.0	24.2	38.1		46.9	39.9	42.1	24.5	38.4	
Crowned Ridge 2		50.4	44.3	45.7	49.9	47.6		55.6	48.6	48.3	50.3	50.7	
Dak. Range 1 & 2		43.5	36.0	39.6	38.7	39.5		45.9	37.6	40.7	39.1	40.8	
Foxtail		42.4	44.0	44.5	47.4	44.6		51.3	48.7	49.8	48.4	49.6	
Freeborn		45.1	43.1	42.8	44.9	44.0		50.7	43.5	48.8	46.7	47.4	
Grand Meadow		29.1				29.1		30.7				30.7	
Grand Rpwr.			37.2	43.3	43.2	41.2			38.3	43.7	43.9	42.0	
Jeffers		54.3	49.8	50.4	51.0	51.4		54.9	49.9	51.5	51.2	51.9	
Lake Benton 2		51.8	49.1	49.7	50.1	50.2		52.3	51	51.8	52	51.8	
Mower		40.8	36.5	39.5	38.6	38.9		41.2	36.7	39.6	38.7	39.1	
Nobles		23.9				23.9		38.7				38.7	
Nobles Repower			42.6	42.9	47.1	44.2			44.2	46.9	47.1	46.1	
Northern Wind			39.9	46.0	44.7	43.5			41.9	48.6	47.2	45.9	
Pleasant Valley		49.5	42.6	44.1	26.5	40.7		49.6	43	44.4	26.7	40.9	
Rock Aetna			45.3	58.5	60.1	54.6			46.3	59.3	61.1	55.6	
Average		**45.6**	**43.2**	**45.9**	**43.7**	**43.2**		**48.4**	**44.4**	**47.6**	**44.4**	**45.3**	

As in the prior year's FCA true-up filing, capacity factors have been, on average (and for most individual years and wind facilities) **[TRADE SECRET DATA HAS BEEN EXCISED]** than forecasted. In response to an information request in the 2023 FCA-True Up, Xcel noted the discrepancy between forecasted and actual capacity factors are affected by wind quality, that "waking and blocking effects may not have fully been accounted for" in initial estimates, causing lower-than-predicted availability of turbines and curtailment.[77]

[76] Figures from Current FCA True-Up Petition, Part C, Attachment 2b.
[77] 2023 FCA True-Up Department Comments at 21-22.

G.4. Wind Conclusion

The Department concludes Xcel has reasonably explained the variance between actual and forecasted wind production. The Department does not have any objections to Xcel's proposed actual 2025 wind recovery but intends to continue monitoring Xcel's actual capacity factors in future FCA filings.

H. MISO COSTS AND REVENUES

The current FCA True-up Petition reflects a sharp adverse variance in MISO cost and revenue outcomes. Xcel forecasted net MISO revenues of $76.5 million, but actual 2025 results were a net cost ($4.7 million). Net MISO sales of 7,412 GWh were 1,819 GWh (19.7%) lower than forecasted. Xcel stated that actual MISO Day 2 and Day 3 activity incurred a net cost due to the "greater volume and costs for purchases from the MISO market than forecast partially in response to generator outages at owned combined cycle plants", and "incremental transmission loss (ITL) costs and RSG/RNU costs were greater than forecast". In addition, greater than forecast revenues from FTRs provided some offset to higher MISO costs."[78]

Xcel's total MISO charges of $187.1 million were $23.4 million (14.3%) higher than Xcel's forecast of $163.7 million. The biggest change was due to the ITL component, which, as noted above, was $54.3 million higher than forecasted. Of note, Congestion costs were closely aligned with the forecast, and $41.1 million higher-than-forecasted FTR revenues partially offset higher-than-forecasted ITL.[79] The Department discusses Xcel's congestion costs in greater detail in the Congestion section above.

Regarding the significant mismatch between actual and forecast ITL amounts, Xcel clarified that the more accurate comparison is $23.7 million of actual ITL versus $9.2 million of forecast ITL. At the same time, Xcel stated that it is requesting recovery of the full $63.5 million in transmission loss costs from the MISO settlement because that amount represents the total transmission loss cost incurred in 2025. Xcel explained that the $63.5 million amount consists of approximately $39.8 million of average system losses plus $23.7 million of ITL.[80]

The Department appreciates the clarification provided in response to DOC IR No. 51. However, the Company's response indicates that the values presented in Table 2 may not represent a consistent forecast-versus-actual comparison. Specifically, the forecast value shown in Table 2 appears to represent only ITL, while the actual value appears to represent total transmission loss costs, which include both ITL and additional system-loss components. As a result, the Table 2 row labeled "Incremental Transmission Losses" does not appear to present a like-for-like comparison between forecast and actual values.

The Department does not conclude, on the current record, that the total $63.5 million of transmission loss costs is unrecoverable. However, the Department finds that the presentation of the ITL variance in Table 2 is not sufficiently transparent to allow the Commission to determine whether the variance

[78] Current FCA True-Up Petition at 14.
[79] *Id.*
[80] Xcel's responses to DOC IR Nos 40 and 51, see Attachment 9 and 10.

reflects differences in actual transmission loss costs or differences in how the metric was defined. Therefore, the Department requests that Xcel provide the following clarifications in its Reply Comments: (1) How the $39.8 million average system losses identified in response to DOC IR No. 51 is reflected in the forecast, if at all; and (2) Provide a revised Table 2 that separately identifies actual ITL, other transmission loss components, and total transmission-loss cost so that the Department can evaluate the variance on a consistent basis.

I. RETAIL SALES

Minnesota actual retail sales were about the same (0.3% higher) as forecasted. According to Xcel, the majority of the deviation from forecast came primarily from weather-related impacts: "lower than expected savings from demand side management (DSM) programs, lower than anticipated load additions from commercial and industrial customers (C&I), increased sales due to extreme weather, lower than forecast Combined Heat and Power (CHP) and Large C&I solar generation, lower than anticipated distributed solar generation, and other non-specified factors."[81] The Department concludes Xcel has reasonably explained this variance and does not have any objections to Xcel's proposed final 2025 actual sales.

J. PROPOSED TRUE-UP

As noted earlier, Xcel has begun to implement its proposed refund as shown in the tariff adjustments in Part A, Attachment 8 to the Company's March 31, 2026 Compliance Filing.[82]

As noted above, Xcel has already implemented a $10 million monthly refund for December 2025-March 2026. Therefore, $91.8 million of additional refunds are needed to achieve the total $131.8 million refund. To process this additional refund, Xcel's April 1, 2026 implementation reduces April-December FCA rates by $91.8 million in aggregate.[83] The Company provides the calculations underlying the proposed true-up by class in Part A, Attachment 3 and 4.

K. GENERAL REPORTING REQUIREMENTS

Overall, the Department concluded Xcel complied with the applicable reporting requirements. Specifically, the Department verified that the current Petition included the information required per the following:

- Minnesota Rules 7825.2800 - 7825.2840, as revised on pages 3 to 4 and approved in Point 1 of the Commission's June 12, 2019 Order in Docket

[81] Current FCA True-Up Petition at 15.
[82] *In the Matter of the Petition of Northern States Power Company for Approval of the 2025 Annual Fuel Forecast and Monthly Fuel Charges*, Compliance Filing – 2025 Annual Fuel Forecast and Monthly Fuel Cost Charges, Xcel Energy, March 31, 2025, Docket No. E002/AA-24-63, (eDockets) 20263-229842-01
[83] Current petition, pages 5-6 ("Proposed True-Up Rate Factors"). While historically Xcel has implemented true- ups at the beginning of September in alignment with schedule approved under FCA reform, Xcel is proposing an accelerated schedule for this year due to the large size of the true-up. Xcel states this proposal is consistent with prior rate adjustments which are de-facto approved after 30 days if no party objects.

No. E999/CI-03-802.[84]

- Annual FCA true-up general reporting guidelines, as outlined on page 7 and approved in Point 5 of the Commission's June 12, 2019 Order in Docket No. E999/CI-03-802.[85]
- Annual FCA true-up reporting compliance matrix specific to Xcel, as shown in Attachment 3 of the March 1, 2019 joint comments and approved in Point 7 of the Commission's June 12, 2019 Order in Docket No. E999/CI-03-802.[86]

V. DEPARTMENT RECOMMENDATIONS

Based on analysis above and the information in the record, the Department recommends the Commission approve Xcel's 2025 FCA True-up Petition with the modifications, as described herein:

- For the King Unit 1 outage, the Department requests that Xcel explain in its Reply Comments whether the $1.5 million warranty recovery has already been flowed back to customers, and if so, where that treatment is reflected. If the warranty recovery has not yet been flowed back, Xcel should explain how and when customers will receive the benefit of that amount.

- For the Prairie Island Unit 1 and 2 refueling outage credits related to the cooling pump seal, the Department requests Xcel to address in Reply Comments where these credits were reflected in base rates, including references to the relevant schedules or workpapers in Docket No. E002/GR-24-320.

- For the Riverside outage, the Department recommends that the Commission reserve the determination of prudence and recovery of Riverside-related replacement power costs and refer the Riverside issue to a contested case, where the record can be fully developed, including through engineering analysis. The contested case record should address whether Xcel prudently incurred Riverside-related replacement power costs, including engineering causation, outage management, the reasonableness of the Company's replacement power cost estimate, and the extent to which insurance or third-party recoveries reduce the net amount properly borne by customers. The Department made a similar recommendation in Xcel's current pending rate case in Docket E002/GR-24-320 regarding the Riverside outage.

- The Department requests that Xcel provide the following clarifications in its Reply Comments: (1) How the $39.8 million of average system losses identified in response to DOC IR No. 51 is reflected in the forecast, if at all; and (2) Provide a revised Table 2 that separately identifies actual ITL, other transmission-loss components, and total transmission-loss cost.

[84] June 2019 Fuel Clause Investigation Docket Order.
[85] *Id.*
[86] *Id.*

Attachments

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☒ **Public Document**

Xcel Energy		Information Request No.	42
Docket No.:	E002/AA-24-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Cuong Ngo, Andrew Golden		
Date Received:	March 11, 2026		

Question:
Topic: CSG generation
Reference(s): True-up petition, page 12

a. Please explain why the actual 2025 CSG generation of 1,607 GWh was 524 GWh (24.59%) lower than forecasted.
b. Please explain how the lower-than-forecast CSG generation affected:
    - CSG bill credits,
    - above-market CSG costs, and
    - total FCA costs.
c. Given that the CSG generation has been relatively flat for the past three years (1,504 GWh in 2023; 1,606 GWh in 2024; and 1,607 GWh in 2025), how does the Company expect the program to continue growing in the future?

Response:
a) The CSG MWh generation forecast in a given year relies on a variety of assumptions. For example, generation for a given year is based on a two-year ahead forecast of both MW and MWh. The MW forecast requires an assumption of how many MW are approved by the DOC is a given year and then how many of those CSG are commercialized and put into service given the forecast year for each approval year. The Company must also predict how many MWh are produced by those MWs forecasted.

Therefore, the 2025 forecast was created in 2024 before the actual data associated with the 2024 year was available. The Company attributes the following to MWh actuals for 2025 falling below expectations:

- Solar Output – The Company estimates that 23 percent of the MWh shortfall was due to lower than expected sunshine consistent with the shortfall of the other solar PPAs
- MW Forecast – The Company estimates that 46 percent of the MWh shortfall was due to fewer MWs being put into production by developers than forecast.

MWh Forecast per MW – The Company estimates the remaining 31 percent of the MWh shortfall is due to lower MWh per MW forecast. The Company is planning to perform an analysis on this item as we prepare the 2027 fuel forecast.

b) As shown in Figure 9 of our February 27, 2026 filing, the reduction in CSG generation amounts to $58.973 million less in CSG bill credits, $50.335 million less in above market costs, and $58.973 million less in CSG costs in the fuel clause than forecasted.

c) The actual MWh mentioned in the question are driven from the variables mentioned in the Company's answer in a) and aren't necessarily predictive for future CSG production by themselves. The DOC continues to approve new CSG to be built. The Company will continue to forecast those MW additions resulting from developer activity, and forecast a baseline MWh per average MW expected to be in service during the forecast year. Since solar output is variable, the Company expects there to be either an over and under production of CSG solar depending on how sunny and snowy the year is.

Preparer: Nick Paluck
Title: Manager, Regulatory Analysis
Department: NSPM Regulatory
Telephone: 612.330.2905
Date: March 23, 2026

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☐ **Public Document – Not-Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy		Information Request No.	48
Docket No.:	E002/AA-24-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Cuong Ngo, Andrew Golden		
Date Received:	March 11, 2026		

Question:
Topic: Sherco G1 forced outages.
Reference(s): True-up petition, Part C, Attachments 4a.

a. For Sherco_G1 forced outages, where Attachment 4a, "Failure History During Reporting Period" column indicates "similar to" prior events or repeat conditions, why was the recurrence not prevented sooner?
b. Please state whether the Company concludes the initiating failure in each such event was preventable with reasonable inspection and maintenance and provide the basis for that conclusion.
c. Was the initiating failure preventable with reasonable inspection and maintenance?
d. Please identify any changes made in 2025 to maintenance practices, inspection intervals, operating procedures, or capital planning as a result of these recurring Sherco_G1 events.

Response:
Please see Attachment A to this response for responses to subparts a.-d. Because subparts b. and c. are interpreted to ask for the same information, those responses are combined in the attachment.

Preparer:	Jane E. Frazier	Brian Behm
Title:	Prin OPL Support Consultant	Senior Director
Department:	ES Strategy and Performance	Sherco Plant
Telephone:	612-330-7849	651-731-5703
Date:	March 23, 2026	

Outage Category	Primary Reason for Unplanned Outage	Outage Dates		Duration (Days)	Equipment that resulted in the forced outage	Description of Equipment Failure	Change in Energy Costs ($s)	Failure History During Reporting Period
		Start	End					
Forced	Require U1 derated to 555MWn. U1 derate necessary to maintain a max throttle pressure of 1900psi due to RH tube leak.	1/1/2025	1/11/2025	10	Boiler Tubing	Tube leak in the reheat section of the boiler.	387,886	Similar to 1/17/2025, and 7/8/2025.
Forced	Require U1 derated to 555MWn. U1 derate necessary to maintain a max throttle pressure of 1900psi due to RH tube leak.	1/17/2025	3/12/2025	54	Boiler Tubing	Tube leak in the reheat section of the boiler.	2,751,003	Similar to 1/1/2025, and 7/8/2025.
Forced	Unit 1 force offline. Coal Crusher motors OOS, unable to supply U1 with fuel. U1 needs to come off control to burn coal silos out.	3/12/2025	4/30/2025	49	Coal Crusher Motors	While researching replacement options for 2 Coal Crusher Motor it was determined that neither coal crusher motor was rated for the environment they operate in (Class 2 Div 1F). Coal supply to unit 1 was compromised until a replacement option could be found.	5,725,807	Similar to 5/1/2025
Forced	Force offline. Coal Crusher motors OOS, unable to supply fuel. At 0146 hours, unit 1 tripped while trying to go online. Engineering to investigate.	5/1/2025	5/16/2025	15	Coal Crusher Motors	While researching replacement options for 2 Coal Crusher Motor it was determined that neither coal crusher motor was rated for the environment they operate in (Class 2 Div 1F). Coal supply to unit 1 was compromised until a replacement option could be found.	2,622,383	Similar to 3/12/2025
Forced	Require unit offline due to oil bladder failure in 1 Generator Step Up transformer causing an oil leak and potential contaminated oil in the transformer.	5/23/2025	5/31/2025	9	1 Generator Step Up Transformer	Oil bladders for 1 Generator Step Up Transformer (GSU) failed requiring immediate removal from sevice.	1,625,708	Similar to 6/1/2025
Forced	Oil bladder failure in Step Up transformer causing an oil leak and extension due to inclement weather delaying transformer repairs & testing.	6/1/2025	6/28/2025	28	1 Generator Step Up Transformer	Oil bladders for 1 Generator Step Up Transformer (GSU) failed requiring immediate removal from sevice.	10,519,565	Similar to 5/23/2025
Forced	No. 11 transfer feeder belt failure/Boiler feed pump fire requiring a unit trip to prevent further damage/Derate due to 13 BFPT being unavailable caused by a lagging fire	7/5/2025	7/8/2025	2	Boiler Feed Pump	Lagging fire on 13 BFPT. Removed the pump from service to facilitate fire fighting activities. Pump remained isolated until it could be relagged.	813,100	Similar to 7/11/2025
Forced	Unit derated due to 13 BFPT out of service.	7/11/2025	7/13/2025	3	Boiler Feed Pump	Lagging fire on 13 BFPT. Removed the pump from service to facilitate fire fighting activities. Pump remained isolated until it could be relagged.	347,123	Similar to 7/5/2025

Outage Category	Primary Reason for Unplanned Outage	Outage Dates		Duration (Days)	Equipment that resulted in the forced outage	Description of Equipment Failure	Change in Energy Costs ($s)	Failure History During Reporting Period
		Start	End					
Forced	Multiple issues: wet coal, feeders maxed out, cleaning plugged feeders, OOS Moduel maintenace	7/16/2025	7/31/2025	15	Coal Mill Feeders/Scrubber Modules	Wet coal supply to the unit resulted in plugged supply from coal feeders t he coal mill. More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.	2,311,674	Similar to 8/14/2025, 9/1/2025 and 9/4/2025
Forced	Boiler tube leak on the outside wall north end of the boiler requires unit offline to isolate and repair.	7/8/2025	7/11/2025	3	Boiler Tubing	Tube leak in the boiler wall section of the boiler.	1,619,532	Similar to 1/1/2025 and 1/17/2025.
Forced	Unit 1 derated to 660 mws net due to boiler swings at 680 mws net (full load). Engineering and I&C working on a solution.	8/1/2025	8/3/2025	2	Boiler Draft	Boiler draft causing boiler power swings at full load. Derate to allow for stable unit operation unitil engineering could resolve the issue.	10,887	Similar to 8/3/2025
Forced	Derate to 650 net MW due to boiler pressure swings at higher load.	8/3/2025	8/13/2025	10	Boiler Draft	Boiler draft causing boiler power swings at full load. Derate to allow for stable unit operation unitil engineering could resolve the issue.	224,522	Similar to 8/1/2025
Forced	Multiple derates over several days for environmental limits & opacity limits. Multiple instances of module flushing for maintenance	8/14/2025	8/22/2025	7	Scrubber Module	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.	51,937	Similar to 7/16/2025
Forced	Unit derate due to boiler swings, maxed out coal feeders and mill bowl DP's causing feeder runbacks. Derate for 5 mill operation. 16 coal mill feeder OOS.	9/1/2025	9/3/2025	3	Coal Mill Feeders	14 coal mill was isolated for coal leak repairs when 16 coal mill feeder had a motor failure. Unit cannot make full load with more than 1 mill out of service.	34002	Similar to 7/16/2025 and 9/4/2025.
Forced	Due to loss of 7th coal mill and amping out of 6 other feeders we cannot reliably maintain 680 Megawatts. Derated to maintain stability on unit to stay online.	9/4/2025	9/5/2025	1	Coal Mill Feeders	Wet coal supply to the unit resulted in plugged supply from coal feeders t he coal mill.	1,414	Similar to 7/16/2025 and 9/1/2025.

Steps Taken to Alleviate Reoccurrence	a. For Sherco_G1 forced outages, where Attachment 4a, "Failure History During Reporting Period" column indicates "similar to" prior events or repeat conditions, why was the recurrence not prevented sooner?	b & c. Please state whether the Company concludes the initiating failure in each such event was preventable with reasonable inspection and maintenance and provide the basis for that conclusion.	d. Please identify any changes made in 2025 to maintenance practices, inspection intervals, operating procedures, or capital planning as a result of these recurring Sherco_G1 events.
Derated unit to allow unit to stay online and minimize tube leak damage until unit could be removed from service to enter the boiler and repair the leak.	Due to unit 1 retirement date of 12/31/2026, the boiler was not scaffolded and inspected during the spring 2024 outage with the understanding that there would be an increased risk of boiler tube leaks.	No, because reasonable insepections and maintenance were completed during the 2024 outage given unit remaining life. Tube leaks have occurred on all 3 units at various times even with boiler scaffolding and extensive outage boiler work due to the corrosive and abrasive nature of coal fired operation.	No changes made in 2025.
Unit removed from service and tube leak was repaired.	Due to unit 1 retirement date of 12/31/2026, the boiler was not scaffolded and inspected during the spring 2024 outage with the understanding that there would be an increased risk of boiler tube leaks. The boiler was explosively cleaned and inspected inspected with a drone with no major issues found.	No, because reasonable insepections and maintenance were completed during the 2024 outage given unit remaining life. Tube leaks have occurred on all 3 units at various times even with boiler scaffolding and extensive outage boiler work due to the corrosive and abrasive nature of coal fired operation.	No changes made in 2025.
Replaced 1 and 2 Coal Crusher Motors with properly rated motors.	Unit 1 and 2 coal crusher motors were originally installed in 1976 as Class 2 Div 2 motors though they had a specification to be installed as Class 2 Div 1 group F motors. This discrepancy was not discovered until a failure of 1 coal crusher motor required a replacement motor and it was found that both motors were installed with the incorrect rating. Unit 1 was taken offline until a properly rated motor could be procurred and installed. Recurrance is solely due to the incident going over multiple months.	No, issue was identified when working with a vendor to replace a failed coal crusher motor.	Motors were replaced with properly rated motors.
Replaced 1 and 2 Coal Crusher Motors with properly rated motors.	Unit 1 and 2 coal crusher motors were originally installed in 1976 as Class 2 Div 2 motors though they had a specification to be installed as Class 2 Div 1 group F motors. This discrepancy was not discovered until a failure of 1 coal crusher motor required a replacement motor and it was found that both motors were installed with the incorrect rating. Unit 1 was taken offline until a properly rated motor could be procurred and installed. Recurrance is solely due to the incident going over multiple months.	No, issue was identified when working with a vendor to replace a failed coal crusher motor.	Motors were replaced with properly rated motors.
Replaced 1 GSU oil bladders. Additionally, replace 1 GSU insulators to prevent potential failure similar to unit 2 in 2023.	Recurrance solely due to this failure being a multi-month event.	No, because oil bladders are internal to the GSU transformer so are not readily available for inspection. GSU followed Xcel Energy inspection and maintenance practices consitent with industry standards including routine transformer oil sampling with no immediate issues noted. Bladder replacement was schedule with GSU bushing replacement in the fall of 2025 following the summer run.	Oil bladders were replaced as well as the GSU bushings to prevent a similar bushing failure that Unit 2 had suffered in 2023.
Replaced 1 GSU oil bladders. Additionally, replace 1 GSU insulators to prevent potential failure similar to unit 2 in 2023.	Recurrance solely due to this failure being a multi-month event.	No, because oil bladders are internal to the GSU transformer so are not readily available for inspection. GSU followed Xcel Energy inspection and maintenance practices consitent with industry standards including routine transformer oil sampling with no immediate issues noted. Bladder replacement was schedule with GSU bushing replacement in the fall of 2025 following the summer run.	Oil bladders were replaced as well as the GSU bushings to prevent a similar bushing failure that Unit 2 had suffered in 2023.
Extinguish fire and relag Boiler Feed Pump Turbine.	Event ran from 7/5/2026 through 7/13/2026. Derate due to BFPT out of service until replacement lagging could be obtained and the BFPT returned to service. Recurrance due to multiple PCIs entered during this period.	No, because an oil leak that pooled under the lagging at the bottom of the turbine and was not observable operations appears to be the cause of the lagging fire. In addition, minor maintenance was performed on 13 BFPT during the 2024 outage and no outstanding maintenance issues were noted on the turbine prior to the even. BFPT overhauls are completed on a 6 year cycle. 13 BFPT would be scheduled for an overhaul in 2027	No changes made in 2025.
Extinguish fire and relag Boiler Feed Pump Turbine.	Event ran from 7/5/2026 through 7/13/2026. Derate due to BFPT out of service until replacement lagging could be obtained and the BFPT returned to service. Recurrance due to multiple PCIs entered during this period.	No, because an oil leak that pooled under the lagging at the bottom of the turbine and was not observable operations appears to be the cause of the lagging fire. In addition, minor maintenance was performed on 13 BFPT during the 2024 outage and no outstanding maintenance issues were noted on the turbine prior to the even. BFPT overhauls are completed on a 6 year cycle. 13 BFPT would be scheduled for an overhaul in 2027	No changes made in 2025.

Steps Taken to Alleviate Reoccurrence	a. For Sherco_G1 forced outages, where Attachment 4a, "Failure History During Reporting Period" column indicates "similar to" prior events or repeat conditions, why was the recurrence not prevented sooner?	b & c. Please state whether the Company concludes the initiating failure in each such event was preventable with reasonable inspection and maintenance and provide the basis for that conclusion.	d. Please identify any changes made in 2025 to maintenance practices, inspection intervals, operating procedures, or capital planning as a result of these recurring Sherco_G1 events.
Derated until dry coal could be sent to the unit and the wet coal in the coal silos was processed through the coal mills. Recommend using coal barn or feeding from train at burn rate during periods of high rain. Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.	Unit 1 has a legacy issue with smaller silo feeds to and from the feeders, when compared to unit 3, causing plugging issues due to wet or forzen coal supply. Air blasters have been added to the outlet of the coal silos which has improved supply to the coal feeders, however it was previously determined that placing air blasters in the outlet from the coal feeders into the coal mill was not feasible which has become a potential choke point when the plant is sent wet or frozen coal. Additionally, managed decline on unit 1 due to retirement date of 12/31/2026 has resulted in acceptance of additional risk for derates due to scrubber module performance.	No. Normal coal mill and coal feeder maintenance continued in 2025 which would not have prevented this occurance due to the legacy piping diameter to and from Unit 1 coal feeders.	No changes made in 2025.
Unit removed from service and tube leak was repaired.	Due to unit 1 retirement date of 12/31/2026, the boiler was not scaffolded and inspected during the spring 2024 outage with the understanding that there would be an increased risk of boiler tube leaks.	No, because reasonable insepections and maintenance were completed during the 2024 outage given unit remaining life. Tube leaks have occurred on all 3 units at various times even with boiler scaffolding and extensive outage boiler work due to the corrosive and abrasive nature of coal fired operation.	No changes made in 2025.
SmartBurn was contract to perform boiler controls tunning to resolve boiler swing issues. Adjusted boiler draft input into the fuel control calculations to ensure stable operations.	Ongoing issue with boiler draft. Contracted SmartBurn to analyze the issue and recommend repairs. Event ran from 8/1/2025 through 8/13/2025. Recurrance due to a new PCI being entered that resulted in a deeper derate.	No, legacy issue discovered by SmartBurn following extensive review of the units boiler draft control scheme.	SmartBurn made changes to the fuel control logic and tuned the boiler to remove boiler draft swings.
SmartBurn was contract to perform boiler controls tunning to resolve boiler swing issues. Adjusted boiler draft input into the fuel control calculations to ensure stable operations.	Ongoing issue with boiler draft. Contracted SmartBurn to analyze the issue and recommend repairs. Event ran from 8/1/2025 through 8/13/2025. Recurrance due to a new PCI being entered that resulted in a deeper derate.	No, legacy issue discovered by SmartBurn following extensive review of the units boiler draft control scheme.	SmartBurn made changes to the fuel control logic and tuned the boiler to remove boiler draft swings.
Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.	Managed decline on unit 1 due to retirement date of 12/31/2026 has resulted in acceptance of additional risk for derates due to scrubber module performance.	Yes, however, managed decline on unit 1 has resulted in acceptance of additional risk for derates due to scrubber module performance.	No changes made in 2025.
Completed leak repair on 14 coal mill and returned to service. Completed feeder motor repairs to restore redundancy.	Plant was working dilegently to repair a hard to reach coal leak on 14 coal mill that required the mill to be out of service for repair when an unexpected failure of 16 coal mill feeder motor occurred. Unable to make full load with more than one coal mill out of service.	No, unexpected failure of a motor while fixing a coal like on another coal mill.	No changes made in 2025.
Derated until dry coal could be sent to the unit and the wet coal in the coal silos was processed through the coal mills. Recommend using coal barn or feeding from train at burn rate during periods of high rain.	Unit 1 has a legacy issue with smaller silo feeds to and from the feeders, when compared to unit 3, causing plugging issues due to wet or forzen coal supply. Air blasters have been added to the outlet of the coal silos which has improved supply to the coal feeders, however it was previously determined that placing air blasters in the outlet from the coal feeders into the coal mill was not feasible which has become a potential choke point when the plant is sent wet or frozen coal.	No. Normal coal mill and coal feeder maintenance continued in 2025 which would not have prevented this occurance due to the legacy piping diameter to and from Unit 1 coal feeders.	No changes made in 2025.

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Xcel Energy		Information Request No.	53
Docket No.:	E002/AA-24-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Cuong Ngo, Andrew Golden		
Date Received:	March 26, 2026		

Question:
Topic: Sherco G1 – Managed Decline, Accepted Risk, and Preventable Events
Reference(s): DOC IR No. 48 response.

In response to DOC IR No. 48, the Company stated that, for certain Sherco G1 events, because Unit 1 is scheduled to retire on December 31, 2026, the boiler was not scaffolded and inspected during the 2024 outage with the understanding that there would be an increased risk of boiler tube leaks. The Company also stated that "managed decline" resulted in acceptance of additional risk for certain scrubber-module derates. Please explain why managed decline is a reasonable basis for charging customers for outage replacement power costs associated with accepted additional risk, rather than assigning those costs to shareholders.

Response:
As the Company has discussed in previous Fuel Forecast proceedings and in rate case testimony, as assets near a retirement date, usually within a two-year window, we reduce capital and O&M spending. For example, Sherco Unit 2 had an overhaul in 2022 and had a retirement date of December 31, 2023. During this overhaul, the outage scope was reduced to required inspections and minimal preventative maintenance.

As work scopes are reduced for retiring units, there are inherent reliability risks that must be weighed. In the example of Sherco Unit 2, with minimum work performed during the 2022 overhaul, there are risks of increased boiler tube leaks or equipment failures causing derates or a forced outage, reducing energy availability factor (EAF). Xcel Energy's goal is to balance reliability and prudent spending on a retiring asset.

In summary, the Company must weigh the costs to customers of additional expenditures on incremental improvements to unit performance against the potential for some additional outages and resulting increases in purchased power expense. The Company works hard to strike a reasonable balance between these two expenses.

Preparer:	Allen D. Krug
Title:	AVP, State Regulatory Policy
Department:	NSPM Regulatory
Telephone:	612-330-6270
Date:	April 6, 2026

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Xcel Energy		Information Request No.	47
Docket No.:	E002/AA-24-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Cuong Ngo, Andrew Golden		
Date Received:	March 11, 2026		

Question:
Topic: Riverside outage.
Reference(s): FCA true-up filing; Part C, Attachment 5; Riverside outage update – Pages 18,19 of the true-up Petition

Please identify the specific amount of Riverside outage-related FCA cost that the Company proposes to recover from customers through the current true-up filing:

a. The amount the Company would need to defer, remove, track separately, or otherwise exclude from current recovery if the Commission were to reserve prudence of Riverside outage-related costs for later engineering review or contested case proceeding;
b. The monthly carrying amount associated with that Riverside-related balance;
c. Accounting treatment the Company proposes if the Commission delays recovery pending further review; and
d. Whether the Company has maintained sufficient records to separately track Riverside-related FCA costs for later true-up, refund, or disallowance.

Response:

a. The Riverside outage-related FCA incremental cost that the Company is seeking to recover through the current true-up filing is estimated at **[PROTECTED DATA HAS BEEN EXCISED]**.
b. The Company has not calculated a monthly carrying amount for the Riverside-related balance but estimates approximately $880,000 in carrying charges for 2025 based on the Minnesota jurisdictional amounts identified in Part A and using the U.S. prime rate.
c. The Company would maintain the Riverside outage-related FCA cost in a deferred account on the balance sheet until recovery is determined.
d. No, the Company does not have the ability to determine from the invoices paid those that are Riverside outage-related FCA costs. Such costs would have to be

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determined by production cost modeling or another replacement power estimate methodology.

Portions of this Information Request are marked "Not-Public" they contains information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential forecast data that derives an independent economic value from not being generally known or readily ascertainable by others who could obtain economic value or a financial advantage from its disclosure or use. The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500.

Preparer:	Karen Everson	Keith Parks
Title:	Director	Manager, Data Science and Analytics
Department:	Utility Accounting	Market Operations
Telephone:	715-737-2417	303-308-2787
Date:	March 23, 2026	

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Xcel Energy		Information Request No.	54
Docket No.:	E002/AA-24-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Cuong Ngo, Andrew Golden		
Date Received:	March 26, 2026		

Question:
Topic: Insurance Coverage
Reference(s): DOC IR No. 49 response.

In response to DOC IR No. 49, the Company stated that it has property coverage with extra expense coverage that applies subject to a $13.75 million sublimit. Please provide:

a. Whether any portion of the Riverside outage-related FCA incremental cost estimate could fall within the policy's "Extra Expense" coverage. If yes, identify which categories of cost could qualify and how the Company evaluated that issue.
b. The accounting treatment the Company will use to record any insurance proceeds associated with the Riverside outage.
c. The mechanism through which customers would receive the benefit of any insurance proceeds associated with Riverside outage-related costs.

Response:

a. The adjustment of the Riverside generator claim is in the early stages. There is the potential for temporary repairs to fall under the extra expense coverage, but the costs are not finalized. These costs will be included in the final claim total.
b. Unknown, the insurance claim process has not been completed. The Company commits to providing updates regarding this issue as additional information is available.
c. Unknown, the insurance claim process has not been completed. The Company commits to providing updates regarding this issue as additional information is available.

Preparer:	Robert L. Miller
Title:	Director, Hazard Insurance
Department:	Hazard Insurance Management
Telephone:	612-216-8114
Date:	April 6, 2026

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Xcel Energy		Information Request No.	44
Docket No.:	E002/AA-24-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Cuong Ngo, Andrew Golden		
Date Received:	March 11, 2026		

Question:
Topic: Planned outages
Reference(s): True-up petition, Part C, Attachments 4b and 5b.

a. Please explain Xcel's planning process for outage timing and duration to minimize customer cost impacts, including how the Company accounts for market conditions and replacement power costs when selecting outage windows.
b. Identify all planned outages in 2025 where the scope expanded due to discovery (including extensions), and provide:
    - What was discovered?
    - Why it was not detected pre-outage;
    - Whether pre-outage inspections/condition monitoring were adequate;
    - Incremental days and incremental energy cost impact attributable to discovery vs baseline plan.
c. For the Allen S King plant, please provide the forecast assumptions used in the 2025 FCA forecast regarding planned outage days and explain why the scheduled outage was not reflected in forecasted planned outage costs.

Response:

a. Xcel Energy Generation works collaboratively with Xcel Energy Power Operations to schedule major overhauls to be least impactful to regional reliability and market pricing. The generating unit overhaul proposed schedule is submitted to Power Operations, along with unit shutdown and startup load schedules. Power Operations communicates the overhaul plans to the Midcontinent Independent System Operator (MISO) to ensure that Xcel Energy is complying with the NERC standards and ISO protocols regarding overhaul planning. Power Operations ensure that the overhaul schedule energy cost replacements are optimized. Typically, the generating unit outages are performed in the spring season when the energy demand and market prices are lower, and to a lesser extent in the fall.

b. One 2025 planned outage extension occurred in NSP as described below: Allen S. King Plant posted an extension from their planned generator overhaul.
   - What was discovered?
     The planned outage extension was initiated due to turbine valve work and was prolonged due to rework on the generator (generator work addressed in Docket 24-0063 DOC -045.)

   - Why it was not detected pre-outage;
     A turbine valve leak was detected prior to the outage, but the extent of the repairs could not be determined without valve disassembly and detailed inspection that occurred during the overhaul.

   - Whether pre-outage inspections/condition monitoring were adequate;
     Initial condition monitoring did show that one valve needed to be reworked. Upon valve disassembly, the plant made the decision to inspect and repair the remaining valves.

   - Incremental days and incremental energy cost impact attributable to discovery vs baseline plan.
     The turbine valve extension was 16 days, and the vendor rework was 30 days, totaling 46 days with a combined incremental energy cost of $9.9 million.

c. The scheduled outage for the King plant from February 22, 2025 to May 15, 2025 was during the Commission ordered seasonal off-line period, when the plant is modeled as unavailable in the PLEXOS simulation. Since the plant is already off-line, modeling an offline period for a planned outage is not necessary, as the plant is assumed unavailable to operate for the entire period. At the time of our Reply filing there were no outages planned for King during the seasonal operation period in which the plant is assumed available to operate. The Commission ordered seasonal off-line period is not considered a planned outage; therefore the Company has never provided forecast costs during this period.

Preparer:	Jacob R. Grundy	David G. Horneck
Title:	Senior Director	Director, Generating Modeling Services
Department:	High Bridge Combined Cycle	Generating Modeling Services
Telephone:	612-437-7504	303-571-2816
Date:	March 23, 2026	

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Xcel Energy		Information Request No.	45
Docket No.:	E002/AA-24-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Cuong Ngo, Andrew Golden		
Date Received:	March 11, 2026		

Question:
Topic: Outages caused or contributed to by human error
Reference(s): True-up petition, Part C, Attachments 4a, 4b, 5a and 5b.

Please identify each 2025 planned or forced outage, derate, outage extension, post maintenance, and post testing event for which the Company determined that human error caused, contributed to, or materially prolonged the event. For purposes of this request, "human error" includes, but is not limited to, operator error, maintenance error, testing error, procedure deficiency, planning error, contractor error, vendor execution error, configuration error, or supervisory/approval error. For such event, please provide:

a. The plant and unit;
b. The outage/event start and end dates and times;
c. Whether the event was planned, forced, or began as one and became the other;
d. The specific human error identified;
e. The source document identifying the error;
f. Whether the Company concluded the event was preventable with reasonable utility practice;
g. The corrective actions implemented;
h. The number of outage or derate days the Company attributes to human error;
i. The associated 2025 FCA impact, including:
    - Change in energy costs;
    - Average replacement cost;
    - Unit incremental cost, and;
    - any other outage-related FCA costs associated with the event; and whether the Company is seeking recovery of any non-FCA costs related to the event elsewhere.

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Response:
Human error occurred at the Allen S King generator major overhaul in 2025.

a. *The plant and unit:*
Allen S. King Plant, Unit 1
b. *The outage/event start and end dates and times:*
Timeframe associated with the generator rework is 5/31/2025 22:00 through 6/30/2025 22:00.
c. *Whether the event was planned, forced, or began as one and became the other:*
The generator overhaul was a planned outage and became a planned outage extension.
d. *The specific human error identified:*
Vendor execution error
e. *The source document identifying the error:*
Not applicable
f. *Whether the Company concluded the event was preventable with reasonable utility practice:*
The error was incorrect installation of generator couplings and rotor alignment and was preventable.
g. *The corrective actions implemented;*
Correct installation of coupling bolts and re-alignment performed.
h. *The number of outage or derate days the Company attributes to human error:*
30 outage days
i. *The associated 2025 FCA impact, including: Change in energy costs:* estimated
[PROTECTED DATA HAS BEEN EXCISED]

Average replacement cost: estimated [PROTECTED DATA HAS BEEN EXCISED]

Unit incremental cost: estimated
[PROTECTED DATA HAS BEEN EXCISED]

- *any other outage-related FCA costs associated with the event*: none
- *and whether the Company is seeking recovery of any non-FCA costs related to the event elsewhere*: No, given that the event occurred in 2025 and the pending rate case was filed in 2024.

Information in this response is marked "Not-Public" because it is information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential financial data that derives an independent economic value from not being generally known or readily ascertainable by others who could obtain economic value or a financial advantage from its disclosure or use. The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500.

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Preparer:	Jane E. Frazier	Nick J. Detmer
Title:	Principal OPL Support Consultant	Director, Market Operations & Analytics
Department:	ES Strategy and Performance	Market Operations
Telephone:	612-330-7849	303-571-7030
Date:	March 23, 2026	

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Xcel Energy		Information Request No.	52
Docket No.:	E002/AA-24-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Cuong Ngo, Andrew Golden		
Date Received:	March 26, 2026		

Question:
Topic: King Unit 1 Planned Outage Extension
Reference(s): DOC IR No. 44 response; DOC IR No. 45 response.

In response to DOC IR No. 45, the Company identified the King Unit 1 generator rework as a preventable vendor execution error involving incorrect installation of generator couplings and rotor alignment. Please provide the following:

a. Explain whether the Company believes any aspect of Xcel's contractor oversight, supervision, quality assurance, inspection, or acceptance process contributed to the 30-day outage extension, including whether the Company actually supervised the contractors/vendors' work. If not, please explain why not.
b. A statement on whether the Company contends that ratepayers should bear the outage-related replacement power cost caused by the 30-day preventable vendor execution error, and the basis for that position.
c. Whether the Company has sought or plans to seek reimbursement, warranty recovery, credit, or any other financial remedy from the vendor for the error and, if so, the current status of that effort.

Response:

a. None of Xcel Energy's oversight, supervision, quality assurance, inspection, or acceptance process contributed to the 30-day outage extension. Xcel Energy provided substantial oversight and supervision of Original Equipment Manufacturer contractor Siemens Energy, Inc.'s work. This included development of a detailed scope of work, daily site updates regarding progress made, and physical presence during major evolutions. Major scope items included a stator core tightening program, stator re-wedge, radial band tension check, and bump test. Xcel Energy technical personnel were present during the overhaul. During reassembly, Siemens personnel did not appropriately tighten generator coupling bolts, resulting in startup vibration and rework. Bolt tightening was not part of the formal inspection and acceptance process for the

agreed scope of work, as that ability is expected to be within the expertise of our vendors.

b. The Company does maintain that ratepayers should bear the costs included for this outage in its 2025 true-up because these costs were incurred as part of the prudent operation of King, and the fuel clause recovery mechanism covers prudently incurred costs. The Company applied and executed on its standard vendor acceptance, oversight, supervision, quality assurance, and inspection, process. Reliance on that process was reasonable, given that Siemens Energy is a trusted Tier 1 vendor in this industry and is the original equipment manufacturer (OEM) of this equipment. As the OEM, Siemens Energy has internal access to detailed system drawings and related technical information to which other third-party competitors would not have available. Siemens Energy also has many years of positive track record providing similar services as the generator OEM on the Company's similar equipment for other operating companies without incident.

   As the Commission has explained, prudence is evaluated based on whether the utility operated in good faith and reasonably based on the information known at the time:

   > Generally, prudence is reasonable action taken in good faith based on knowledge available at the time of the action or decision. Actions taken in good faith are those taken without malicious intent, exercising the care that a reasonable person would exercise under the same circumstances at the time the decision was made. Prudence is not evaluated using the benefit of hindsight.[1]

   Here, the Company reasonably selected and oversaw the vendor and exercised reasonable care under the circumstances. In summary, human error does occur, as happened here, but that does not render any of the Company's actions imprudent such that recovery should be denied.

c. Following Siemens Energy's completion of the site work, when the unit began start-up sequencing, the unit tripped and was forced offline. Xcel Energy subsequently required Siemens Energy to return to the site to troubleshoot and fix the problem. Pursuant to the warranty terms of their agreement, the Company successfully recovered the approximately $1.5 million cost related to the repair from Siemens Energy. As is typical of any of our vendor contracts,

[1] Docket Nos. G002/CI-21-610 and G999/CI-21-135. *In the Matter of the Northern States Power Company d/b/a Xcel Energy to Recover February 2021 Natural Gas Costs* and *In the Matter of a Commission Investigation into the Impact of Severe Weather in February 2021 on Impacted Minnesota Natural Gas Utilities and Customers.* ORDER DISALLOWING RECOVERY OF CERTAIN NATURAL GAS COSTS AND REQUIRING FURTHER ACTION (October 19, 2022) at 5.

the agreement with the vendor expressly waives recovery of consequential damages, including replacement power costs. Such terms are unacceptable to vendors, who would not agree to perform maintenance work at our facilities if they were contractually obligated to cover such costs. As a result, the Company carefully monitors and outlines work for our vendors, choosing to work with industry-proven professionals.

Preparer: Christopher M. Haack
Title: Director, Capital Projects Procurement
Department: Supply Chain
Telephone: 612-382-9460
Date: April 6, 2026

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Xcel Energy Information Request No. 40
Docket No.: E002/AA-24-63
Response To: Minnesota Department of Commerce
Requestor: Cuong Ngo, Andrew Golden
Date Received: March 11, 2026

Question:
Topic: MISO Charges, Incremental Transmission Losses.
Reference(s): True-up petition, Table 2, page 14; and Part F, WP – 5 of the initial filing;

Upon reviewing the Company's 2025 actual MISO charges report, the Department's understanding of how the Company calculates Incremental Transmission Losses (ITL) is that it is the difference between A. Transmission losses paid to MISO and B. Transmission losses (A-B) as shown in Figure 1 below.

Figure 1. Incremental Transmission Losses Calculation.[1]

INCREMENTAL LOSS CALCULATION		
Loss components above are shown again here		
Day Ahead Asset Loss Amount		
Day Ahead Financial Bilateral Transaction Loss Amount		
Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts		
Day Ahead Non-Asset Loss Amount		
Non-Excessive Loss Amount		
Real Time Asset Loss Amount		
Real Time Distribution of Losses Amount		
Real Time Financial Bilateral Transaction Loss Amount		
Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts		
Real Time Non-Asset Loss Amount		
Transmission losses paid to MISO	A	
Gross system requirements		
Transmission loss percent		
Transmission losses		
Avg system cost per Mwh		
$ Transmission losses	B	
Actual $/MWh		
Actual Requirements (Gross)		
Actual $/kWh		
System Incremental losses	C = A - B	Incremental Transmission losses

[1] Part F, WP – 5 of the initial filing (Docket E002/AA-24-63).

a. Please provide the exact formula the Company used to forecast ITL in the 2025 FCA forecast and the exact formula the Company used to report actual 2025 ITL in this true-up.
b. Please quantify the difference, by month and in total, between:

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- Transmission losses paid to MISO,
- Transmission losses, and
- Reported ITL.

c. If the actual methodology differs from the forecast methodology, explain why that difference is reasonable and provide a revised Table 2 showing what ITL would be under the forecast methodology.

Response:

a. The formula used to forecast ITL in the 2025 FCA forecast is: Transmission Loss paid to MISO – (Control Area Loss * average system cost). The actual 2025 Transmission Loss paid to MISO is determined from the MISO settlement.
b. In Attachment A, please see lines 60-87 of tab "Reply" for the forecast of ITL; see tab "2025 Actual" for actual transmission losses paid to MISO and ITL for 2025, as calculated in accordance with the formula from part a.
c. Actual transmission losses as recorded from the MISO settlement are the total transmission loss cost. For the forecast, part of the transmission loss cost comes from the internal PLEXOS calculation (based on the losses included in the load forecast) and the rest from the ITL. Table 2 in the true-up petition shows total loss costs for 2025 actuals and ITL for 2025 forecast. The actual ITL for 2025, calculated according to the formula listed in part a, is $23.7 Mil (line 87 "2025 Actual"), as compared to $9.2 Mil in the forecast as shown in Table 2.

Portions of Attachment A are marked "Not-Public" as it contains information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential forecast data that derives an independent economic value from not being generally known or readily ascertainable by others who could obtain economic value or a financial advantage from its disclosure or use. The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500.

Revised Response:

Attachment A submitted on March 23, 2026 with our initial response contained the incorrect IR number in the right header. The Company submits this revised response with the correct header. Attachment A is also being provided as a live Excel file.

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Department:	Generation Modeling Services	Generation Modeling Services
Telephone:	303-571-2816	303-571-6320
Date:	March 23, 2026	
REVISED:	**April 7, 2026**	

		4/1/2021	5/1/2021	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	11/1/2021	12/1/2021
Energy	Day Ahead Asset Energy Amount									
Energy	Day Ahead Non-Asset Energy Amount									
Energy	Non-Excessive Energy Amount									
Energy	Real Time Asset Energy Amount									
Congestion	Real Time Non-Asset Energy Amount									
Congestion	Excessive Energy Amount									
Congestion	Day Ahead Asset Congestion Amount									
Congestion	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts									
Congestion	Day Ahead Financial Bilateral Transaction Congestion Amount									
Congestion	Day Ahead Non-Asset Congestion Amount									
Congestion	Non-Excessive Congestion Amount									
Congestion	Real Time Asset Congestion Amount									
Congestion	Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts									
Congestion	Real Time Financial Bilateral Transaction Congestion Amount									
Congestion	Real Time Non-Asset Congestion Amount									
FTR	Auction Revenue Rights Infeasible Uplift Amount									
FTR	Auction Revenue Rights Stage 2 Distribution Amount									
FTR	Auction Revenue Rights Transaction Amount									
FTR	Financial Transmission Guarantee Uplift Amount									
FTR	Financial Transmission Rights Annual Transaction Amount									
FTR	Financial Transmission Rights Full Funding Guarantee Amount									
FTR	Financial Transmission Rights Hourly Allocation Amount									
FTR	Financial Transmission Rights Monthly Allocation Amount									
FTR	Financial Transmission Rights Yearly Allocation Amount									
Loss	Day Ahead Asset Loss Amount									
Loss	Day Ahead Financial Bilateral Transaction Loss Amount									
Loss	Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts									
Loss	Day Ahead Non-Asset Loss Amount									
Loss	Non-Excessive Loss Amount									
Loss	Real Time Asset Loss Amount									
Loss	Real Time Distribution of Losses Amount									
Loss	Real Time Financial Bilateral Transaction Loss Amount									
Loss	Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts									
Loss	Real Time Non-Asset Loss Amount									
RSG/RNU	Day Ahead Revenue Sufficiency Guarantee Distribution Amount									
RSG/RNU	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount									
RSG/RNU	Real Time Demand Response Allocation Uplift Charge									
RSG/RNU	Real Time Miscellaneous Amount									
RSG/RNU	Real Time Net Inadvertent Distribution Amount									
RSG/RNU	Real Time Price Volatility Make Whole Payment Amount									
RSG/RNU	Real Time Revenue Neutrality Uplift Amount									
RSG/RNU	Real Time Revenue Sufficiency Guarantee First Pass Distribution Amount									
RSG/RNU	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amount									
RSG/RNU	Real Time Schedule 49 Cost Distribution Amount									
ASM	Contingency Reserve Deployment Failure Charge Amount									
ASM	Day Ahead Regulation Amount									
ASM	Day Ahead Spinning Reserve Amount									
ASM	Day Ahead Supplemental Reserve Amount									
ASM	Net Regulation Adjustment Amount									
ASM	Real Time Excessive Deficient Energy Deployment Charge Amount									
ASM	Real Time Regulation Amount									
ASM	Real Time Spinning Reserve Amount									
ASM	Real Time Supplemental Reserve Amount									
ASM	Regulation Cost Distribution Amount									
ASM	Spinning Reserve Cost Distribution Amount									
ASM	Supplemental Reserve Cost Distribution Amount									

INCREMENTAL LOSS CALCULATION

Loss components above are shown again here										
Day Ahead Asset Loss Amount										
Day Ahead Financial Bilateral Transaction Loss Amount										
Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts										
Day Ahead Non-Asset Loss Amount										
Non-Excessive Loss Amount										
Real Time Asset Loss Amount										
Real Time Distribution of Losses Amount										
Real Time Financial Bilateral Transaction Loss Amount										
Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts										
Real Time Non-Asset Loss Amount										
Transmission losses paid to MISO										
Gross system requirements										
Transmission loss percent										
Transmission losses										
Avg system cost per Mwh										
$ Transmission losses										
	Actual $/MWh									
Actual Requirements (Gross)										
	Actual $/kWh									
System Incremental losses										

[PROTECTED DATA HAS BEEN EXCISED]

Energy										
Congestion										
FTR										
Loss										
RSG/RNU										
ASM										

		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
Energy	Day Ahead Asset Energy Amount												
Energy	Day Ahead Non-Asset Energy Amount												
Energy	Non-Excessive Energy Amount												
Energy	Real Time Asset Energy Amount												
Congestion	Real Time Non-Asset Energy Amount												
Congestion	Excessive Energy Amount												
Congestion	Day Ahead Asset Congestion Amount												
Congestion	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts												
Congestion	Day Ahead Financial Bilateral Transaction Congestion Amount												
Congestion	Day Ahead Non-Asset Congestion Amount												
Congestion	Non-Excessive Congestion Amount												
Congestion	Real Time Asset Congestion Amount												
Congestion	Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts												
Congestion	Real Time Financial Bilateral Transaction Congestion Amount												
Congestion	Real Time Non-Asset Congestion Amount												
FTR	Auction Revenue Rights Infeasible Uplift Amount												
FTR	Auction Revenue Rights Stage 2 Distribution Amount												
FTR	Auction Revenue Rights Transaction Amount												
FTR	Financial Transmission Guarantee Uplift Amount												
FTR	Financial Transmission Rights Annual Transaction Amount												
FTR	Financial Transmission Rights Full Funding Guarantee Amount												
FTR	Financial Transmission Rights Hourly Allocation Amount												
FTR	Financial Transmission Rights Monthly Allocation Amount												
FTR	Financial Transmission Rights Yearly Allocation Amount												
Loss	Day Ahead Asset Loss Amount												
Loss	Day Ahead Financial Bilateral Transaction Loss Amount												
Loss	Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts												
Loss	Day Ahead Non-Asset Loss Amount												
Loss	Non-Excessive Loss Amount												
Loss	Real Time Asset Loss Amount												
Loss	Real Time Distribution of Losses Amount												
Loss	Real Time Financial Bilateral Transaction Loss Amount												
Loss	Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts												
Loss	Real Time Non-Asset Loss Amount												
RSG/RNU	Day Ahead Revenue Sufficiency Guarantee Distribution Amount												
RSG/RNU	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount												
RSG/RNU	Real Time Demand Response Allocation Uplift Charge												
RSG/RNU	Real Time Miscellaneous Amount												
RSG/RNU	Real Time Net Inadvertent Distribution Amount												
RSG/RNU	Real Time Price Volatility Make Whole Payment Amount												
RSG/RNU	Real Time Revenue Neutrality Uplift Amount												
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ASM	Real Time Regulation Amount												
ASM	Real Time Spinning Reserve Amount												
ASM	Real Time Supplemental Reserve Amount												
ASM	Regulation Cost Distribution Amount												
ASM	Spinning Reserve Cost Distribution Amount												
ASM	Supplemental Reserve Cost Distribution Amount												

[PROTECTED DATA HAS BEEN EXCISED]

INCREMENTAL LOSS CALCULATION

Loss components above are shown again here
Day Ahead Asset Loss Amount
Day Ahead Financial Bilateral Transaction Loss Amount
Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts
Day Ahead Non-Asset Loss Amount
Non-Excessive Loss Amount
Real Time Asset Loss Amount
Real Time Distribution of Losses Amount
Real Time Financial Bilateral Transaction Loss Amount
Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts
Real Time Non-Asset Loss Amount
Transmission losses paid to MISO

Gross system requirements
Transmission loss percent
Transmission losses
Avg system cost per Mwh
$ Transmission losses

Actual $/MWh
Actual Requirements (Gross)

Actual $/kWh

System Incremental losses

Energy
Congestion
FTR
Loss
RSG/RNU
ASM

		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
Energy	Day Ahead Asset Energy Amount												
Energy	Day Ahead Non-Asset Energy Amount												
Energy	Non-Excessive Energy Amount												
Energy	Real Time Asset Energy Amount												
Congestion	Real Time Non-Asset Energy Amount												
Congestion	Excessive Energy Amount												
Congestion	Day Ahead Asset Congestion Amount												
Congestion	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts												
Congestion	Day Ahead Financial Bilateral Transaction Congestion Amount												
Congestion	Day Ahead Non-Asset Congestion Amount												
Congestion	Non-Excessive Congestion Amount												
Congestion	Real Time Asset Congestion Amount												
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Congestion	Real Time Financial Bilateral Transaction Congestion Amount												
Congestion	Real Time Non-Asset Congestion Amount												
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FTR	Financial Transmission Rights Yearly Allocation Amount												
Loss	Day Ahead Asset Loss Amount												
Loss	Day Ahead Financial Bilateral Transaction Loss Amount												
Loss	Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts												
Loss	Day Ahead Non-Asset Loss Amount												
Loss	Non-Excessive Loss Amount												
Loss	Real Time Asset Loss Amount												
Loss	Real Time Distribution of Losses Amount												
Loss	Real Time Financial Bilateral Transaction Loss Amount												
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INCREMENTAL LOSS CALCULATION

Loss components above are shown again here

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Day Ahead Financial Bilateral Transaction Loss Amount													
Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts													
Day Ahead Non-Asset Loss Amount													
Non-Excessive Loss Amount													
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Gross system requirements													
Transmission loss percent													
Transmission losses													
Avg system cost per Mwh													
$ Transmission losses													
Actual $/MWh													
Actual Requirements (Gross)													
Actual $/kWh													
System Incremental losses													

[PROTECTED DATA HAS BEEN EXCISED]

Energy
Congestion
FTR
Loss
RSG/RNU
ASM

		1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024
Energy	Day Ahead Asset Energy Amount						
Energy	Day Ahead Non-Asset Energy Amount						
Energy	Non-Excessive Energy Amount						
Energy	Real Time Asset Energy Amount						
Congestion	Real Time Non-Asset Energy Amount						
Congestion	Excessive Energy Amount						
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Congestion	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts						
Congestion	Day Ahead Financial Bilateral Transaction Congestion Amount						
Congestion	Day Ahead Non-Asset Congestion Amount						
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ASM	Supplemental Reserve Cost Distribution Amount						

INCREMENTAL LOSS CALCULATION

Loss components above are shown again here							
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Non-Excessive Loss Amount							
Real Time Asset Loss Amount							
Real Time Distribution of Losses Amount							
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Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts							
Real Time Non-Asset Loss Amount							
Transmission losses paid to MISO							
Gross system requirements							
Transmission loss percent							
Transmission losses							
Avg system cost per Mwh							
$ Transmission losses							
Actual $/MWh							
Actual Requirements (Gross)							
Actual $/kWh							
System Incremental losses							
Energy							
Congestion							
FTR							
Loss							
RSG/RNU							
ASM							

[PROTECTED DATA HAS BEEN EXCISED]

☐ **Not-Public Document – Not For Public Disclosure**
☐ **Public Document – Not-Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy		Information Request No.	51
Docket No.:	E002/AA-24-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Cuong Ngo, Andrew Golden		
Date Received:	March 26, 2026		

Question:
Topic: MISO Charges, Incremental Transmission Losses (ITL).
Reference(s): True-up petition, Table 2, page 14; and Xcel's response to DOC IR No. 40.

In response to DOC IR No. 40, the Company stated that: "The actual ITL for 2025, calculated according to the formula listed in part a, is $23.7 million (line 87 "2025 Actual"), as compared to $9.2 million in the forecast as shown in Table 2." Based on this response, the Department understands that the actual 2025 amount comparable to the forecast ITL and should be recorded as $23.7 million, not $63.5 million.

a. Please confirm whether the Department's understanding is correct.

b. If not, please explain in detail and reconcile why Table 2 shows total transmission loss costs for 2025 actual and ITL for 2025 forecast.

c. Please explain what transmission loss amount the Company is requesting recovery of, and why this amount is reasonable for recovery from customers.

Response:

a. Yes, we agree that a better comparison of ITL for Table 2 would be to show $23.7 million actual ITL as compared to $9.2 million for forecast ITL.
b. Not applicable.
c. The Company is requesting recovery of the full $63.5 million in transmission loss costs from the MISO settlement because that value represents the full transmission loss cost of delivering energy to customers in 2025. The ITL represents only a portion of transmission losses. Please see Row 79 of Attachment A to the Company's response to Information Request No. DOC-40, showing a total of approximately $39.8 million of average system losses that combines with $23.7 million ITL to equal $63.5 million. As the actual total cost incurred, its recovery is reasonable.

Preparer:	Mark Ritkouski	David G Horneck
Title:	Sr. Generation Modeling Analyst	Director, Generation Modeling Services
Department:	Generation Modeling Services	Generation Modeling Services
Telephone:	303-571-6320	303-571-2816

Preparer:	Amy Mignella
Title:	Regulatory Consultant
Department:	Generation Modeling Services
Telephone:	303-571-6320
Date:	April 6, 2026

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of people by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Comments

Docket No. E002/AA-24-63

Dated this **15th** day of **April 2026**

/s/Sharon Ferguson

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Kevin	Adams	kadams@caprw.org	Community Action Partnership of Ramsey & Washington Counties		450 Syndicate St N Ste 35 Saint Paul MN, 55104 United States	Electronic Service		No	24-63AA-24-63
2	Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy		414 Nicollet Mall Fl 5 Minneapolis MN, 55401 United States	Electronic Service		Yes	24-63AA-24-63
3	Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy		414 Nicollet Mall7th Floor Minneapolis MN, 55401 United States	Electronic Service		Yes	24-63AA-24-63
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	24-63AA-24-63
5	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 St. Paul MN, 55101 United States	Electronic Service		Yes	24-63AA-24-63
6	Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	24-63AA-24-63
7	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	24-63AA-24-63
8	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	24-63AA-24-63
9	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	24-63AA-24-63
10	John	Coffman	john@johncoffman.net	AARP		871 Tuxedo Blvd. St, Louis MO, 63119-2044 United States	Electronic Service		No	24-63AA-24-63
11	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	24-63AA-24-63
12	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	24-63AA-24-63
13	James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	24-63AA-24-63

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
14	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		Yes	24-63AA-24-63
15	Richard	Dornfeld	richard.dornfeld@ag.state.mn.us		Office of the Attorney General - Department of Commerce	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul MN, 55101 United States	Electronic Service		No	24-63AA-24-63
16	Christopher	Droske	christopher.droske@minneapolismn.gov	Northern States Power Company dba Xcel Energy-Elec		661 5th Ave N Minneapolis MN, 55405 United States	Electronic Service		No	24-63AA-24-63
17	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	24-63AA-24-63
18	Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy		414 Nicollet Mall - 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		Yes	24-63AA-24-63
19	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	24-63AA-24-63
20	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	24-63AA-24-63
21	Lucas	Franco	lfranco@liunagroc.com	LIUNA		81 Little Canada Rd E Little Canada MN, 55117 United States	Electronic Service		No	24-63AA-24-63
22	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	24-63AA-24-63
23	Allen	Gleckner	agleckner@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	24-63AA-24-63
24	Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY		401 Nicollet Mall FL 8 Minneapolis MN, 55401 United States	Electronic Service		Yes	24-63AA-24-63
25	Shubha	Harris	shubha.m.harris@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401 - FL 8 Minneapolis MN, 55401 United States	Electronic Service		Yes	24-63AA-24-63

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26	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	24-63AA-24-63
27	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	24-63AA-24-63
28	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	24-63AA-24-63
29	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	24-63AA-24-63
30	Frank	Hornstein	frank.hornstein@minneapolismn.gov	City of Minneapolis		350 South 5th Street Minneapolis MN, 55415 United States	Electronic Service		No	24-63AA-24-63
31	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	24-63AA-24-63
32	Richard	Johnson	rickjohnson@cozen.com	Cozen O'Connor		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	24-63AA-24-63
33	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-63AA-24-63
34	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	24-63AA-24-63
35	Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-63AA-24-63
36	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	24-63AA-24-63
37	Ryan	Long	ryan.j.long@xcelenergy.com			414 Nicollet Mall 401 8th Floor Minneapolis MN, 55401 United States	Electronic Service		Yes	24-63AA-24-63
38	Alice	Madden	alice@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis	Electronic Service		No	24-63AA-24-63

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						MN, 55406 United States				
39	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	24-63AA-24-63
40	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		Yes	24-63AA-24-63
41	Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc		414 Nicollet Mall 7th Floor Minneapolis MN, 55401 United States	Electronic Service		Yes	24-63AA-24-63
42	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	24-63AA-24-63
43	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-63AA-24-63
44	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	24-63AA-24-63
45	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	24-63AA-24-63
46	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	24-63AA-24-63
47	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	24-63AA-24-63
48	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	24-63AA-24-63
49	Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy		414 Nicollet Mall FL 5 Minneapoli MN, 55401 United States	Electronic Service		Yes	24-63AA-24-63
50	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	24-63AA-24-63
51	Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine,		225 South Sixth Street	Electronic Service		No	24-63AA-

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
				P.A.		Suite 3500 Minneapolis MN, 55402 United States				24-63
52	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	24-63AA-24-63
53	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN, 55423 United States	Electronic Service		No	24-63AA-24-63
54	Joshua	Smith	joshua.smith@sierraclub.org			85 Second St FL 2 San Francisco CA, 94105 United States	Electronic Service		No	24-63AA-24-63
55	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	24-63AA-24-63
56	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	24-63AA-24-63
57	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	24-63AA-24-63
58	Scott	Strand	sstrand@elpc.org	Environmental Law & Policy Center		60 S 6th Street Suite 2800 Minneapolis MN, 55402 United States	Electronic Service		No	24-63AA-24-63
59	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	24-63AA-24-63
60	Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine		225 South Sixth Street, Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	24-63AA-24-63
61	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	24-63AA-24-63
62	Patrick	Zomer	pzomer@cozen.com	Cozen O'Connor		150 S. 5th Street, #1200 Minneapolis MN, 55402 United States	Electronic Service		No	24-63AA-24-63