

## Staff Briefing Papers

**Meeting Date** July 2, 2026

**Agenda Item 2\***

**Company** Northern States Power Co. d/b/a Xcel Energy

**Docket No.** E-002/AA-24-63

**In the Matter of Xcel Energy’s Petition for Approval of its Annual Automatic Adjustment Charges for the Period of January 2025 through December 2025.**

**Issues** Should Xcel Energy’s 2025 Annual Fuel and Purchased Energy Charge Rider true-up be approved?

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✓ **Relevant Documents**

**Date**

Xcel Energy – Compliance Report Filing (Public and Trade Secret)	February 27, 2026
Xcel Energy – Errata to Compliance Report	March 4, 2026
Department of Commerce – Comments (Public and Trade Secret)	April 15, 2026
Xcel Energy – Reply Comments (Public and Trade Secret)	May 1, 2026
Department of Commerce – Response to Reply Comments	May 15, 2026

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The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

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## I. Background

The Minnesota Public Utilities Commission (Commission) authorized Northern States Power Co., d/b/a Xcel Energy (Xcel, Xcel Energy or the Company) in its November 8, 2024 Order in the instant docket to implement its 2025 Fuel Clause Adjustment (FCA) forecast, based on forecasted sales of 26,788,077 MWh and costs of \$891,200,000.<sup>1</sup>

On October 22, 2025, Xcel Energy requested a fuel cost adjustment due to over-collections of approximately \$67 million as of August 31, 2025. Xcel Energy proposed reducing the monthly fuel rates by \$10 million per month for four months, beginning December 1, 2025, for a total reduction of \$40 million.<sup>2</sup> To expedite refunds to customers, the Company proposed an implementation date earlier than September 1, 2026, as specified in the June 12, 2019 Order in Docket No. E999/CI-03-802.

The Company noted that the FCA reform process approved by the Commission allows a utility to adjust its approved fuel rates in the case of a significant unforeseen impact, resulting to a change to the total annual forecast of plus or minus 5 percent. The primary drivers for the overcollection are lower costs for natural gas generation than forecast and lower Community Solar Garden (CSG) costs due to less CSG generation than assumed in the forecast. Xcel therefore concluded that the over-collection due to a variety of market forces meets the definition of a “significant unforeseen impact.”<sup>3</sup>

The Company stated it would file the full 2025 actual results in its March 2026 True-Up filing in this docket, and propose a refund plan for the 2025 year-end results at that time.

On November 24, 2025, with no party having filed an objection to Xcel’s October 22, 2025 proposed revised FCA rates within 30 days, the Company submitted a compliance filing with the revised rates.

On February 27, 2026, Xcel Energy filed a Petition to true-up the 2025 fuel cost charges, in compliance with the annual reporting requirements for actual fuel costs established in the FCA Reform Docket. The Petition included a proposal to adjust the monthly fuel rates on April 1, 2026.

On March 4, 2026, Xcel filed an Errata to the Annual True-up Compliance report, to include Part B, Attachment 16, inadvertently excluded from the initial Compliance filing.

On March 31, 2026, Xcel submitted a compliance filing to provide a redline and final version of the Fuel Clause Rider tariff sheet with revised 2026 fuel cost factors.

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<sup>1</sup> MPUC November 11, 2025 Order; Ordering Paragraph 2.

<sup>2</sup> Xcel’s October 22, 2025 Compliance filing; at 1.

<sup>3</sup> Docket No. E999/CI-03-802. In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments. ORDER APPROVING ADDITIONAL DETAILS OF THE NEW FUEL CLAUSE ADJUSTMENT PROCESS (June 12, 2019).

On April 15, 2026, the Department filed its Comments to Xcel's February 27, 2026 Compliance filing and recommended approval of the Petition with modifications.

On May 1, 2026, Xcel filed a Reply Comments to the Department's April 15, 2026 Comments and responded to modifications proposed by the Department and provided additional information as requested.

On May 15, 2026, the Department filed a Response to Xcel's Reply Comments, in which it recommended approval of the Petition with specific modifications.

## II. Discussion

### A. Xcel Energy – True-Up Report

In the Commission's December 17, 2017 Order, an approval for New Annual Fuel Clause Adjustment Requirements and Setting Filing Requirements in Docket No. E-999/CI-03-802 was issued. The Order requires that if annual revenues collected (dollars per 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.<sup>4</sup>

Xcel Energy's 2025 fuel expense was \$845.7 million, or \$45.5 million lower than the approved forecast of \$891.2 million. The average fuel cost of \$30.97 per MWh was 6.9 percent lower than the authorized rate of \$33.27 per MWh. The actual fuel cost collections were \$907.6 million, 1.8 percent higher than forecast, corresponding to Minnesota jurisdictional sales that were 1.9 percent greater than forecast.<sup>5</sup>

Fuel cost over-collection for items included in the approved forecast is \$62.0 million, of which \$10.4 million has already been refunded through Xcel's mid-year adjustment, which reduced the 2025 Minnesota fuel over-collection to \$51.6 million.<sup>6</sup> Additionally, the Company made adjustments to refund customers \$83.1 million of nuclear production tax credit (NPTC) transactions for 2025, and collected from customers \$3.1 million over-refunded from the Sherco Unit 3 Replacement Power Costs refund. With inclusion of the adjustments, the final 2025 amount to be returned to customers is \$131.8 million.<sup>7</sup>

The Commission's November 8, 2024 Order in this Docket approved Xcel's fuel forecast and revised monthly rate factors by customer class for calendar year 2025. Several updates to the approved 2025

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<sup>4</sup> Xcel's 24-63 FCA Compliance Report; at 2.

<sup>5</sup> *Id.*; at 1.

<sup>6</sup> *Id.*

<sup>7</sup> *Id.*

rates were made throughout the year. First, rates were adjusted on April 1, 2025 per the Company's March 3, 2025 True-Up filing in Docket No. E-002/AA-23-153. Given no party objection, Xcel implemented the adjustment as proposed. Secondly, the Company's monthly rates were later adjusted pursuant to the Company's October 22, 2025 filing in this Docket, which took effect on December 1, 2025. In this report, the Company presented the final 2025 Fuel Forecast True-Up Report containing final actual data for calendar year 2025, which includes all the adjustments impacting 2025.

Table 1 below summarizes the 2025 forecast to actuals comparison.

**Table 1<sup>8</sup>**  
**2025 Fuel Cost and Revenue Comparison Summary MN Jurisdiction**

	Actual (000s)	Forecast (000s)	Variance (000s)	Variance (%)
Total FCA Costs	\$845,660	\$891,200	(\$45,540)	-5.1%
MWh Sales <sup>4</sup>	27,308,156	26,788,077	520,079	1.9%
FCA Cost in \$/MWh	\$30.97	\$33.27	(\$2.30)	-6.9%
Fuel Collections	\$907,646	\$891,200	\$16,446	1.8%
2025 Mid-Year Adjustment	(\$10,367)			
(Over) Under Recovery	(\$51,619)			
Net 2025 Nuclear PTC Credits	(\$83,059)			
Land Sales Credits	(\$199)			
Net Balance - Sherco 3 Refund	\$3,105			
<b>Total (Over) Under Recovery</b>	<b>(\$131,772)</b>			

### 1. Management of 2025 Fuel Costs and Prudence of True-up Proposal

In 2025, the primary factor resulting to lower than forecast costs was lower solar generation from the CSG program. The year ended with lower than forecast volumes, which resulted in \$59.0 million lower costs for customers than originally forecasted as shown in Section D.9, Figure 9.

Additionally, natural gas costs were \$90.4 million lower than forecast, driven by lower than forecast volume of natural gas combined cycle generation. The reduction in volume was driven by greater outage days at combined cycle plants, principally related to the generator failure at Riverside.<sup>9</sup> Xcel noted that natural gas prices were lower than forecast for the winter months, but remained close to forecast for the rest of the year. Offsetting lower natural gas costs were \$81.2 million higher net

<sup>8</sup> Xcel's 24-63 FCA Compliance Report; at 4.

<sup>9</sup> Xcel's 24-63 FCA Compliance Report; 5.

costs from the MISO market as shown in Section D.12, Figure 12.<sup>10</sup>

## 2. Proposed True-Up Rate Factors

The Company proposed to refund \$131.8 million to customers through the monthly Fuel Cost Charge, from April 2026 through December 2026. Xcel observed that while the June, 2019 Order established a schedule for review of the True-up filing to allow for Commission approval before a true-up implementation date of September 1, Ordering paragraph 3 of the June 2019 Order allows the Company to implement a proposed rate adjustment due to unforeseen impact, if no party objects to the revised rates within 30 days.<sup>11</sup> Xcel reiterated that due to factors that could not have been predicted at the time of the 2024 forecast, the 2025 true-up meets the criteria for unforeseen circumstances, and the true-up amount exceeds the required threshold of plus or minus 5 percent.<sup>12</sup>

On March 31, 2026, Xcel submitted a compliance filing in which a redline and final version of the Fuel Clause Rider tariff sheet with revised 2026 fuel cost factors effective April 1, 2026,<sup>13</sup> and noted that no party had objected to the revised rate proposal in the Company's 2025 Fuel Forecast True-up Report filed on February 27, 2026.

The Commission's November 9, 2023 Order in Docket No. E-002/AA-23-153 approved the allocation of fuel costs to Minnesota, using the FERC-approved Interchange Agreement tariff, which governs cost allocation between the NSP Minnesota and NSP-Wisconsin operating companies. Consequently, for the 2025 true-up, the Company assigned costs to the NSP-Minnesota operating Company through the application of the Interchange Agreement energy allocator.<sup>14</sup> This allows customers and the Company to remain whole on prudently incurred fuel cost recovery.

To determine the proposed true-up factors by customer class, Xcel compared the 2025 forecasted Minnesota cost to the actual cost, which includes the mid-year rate adjustment. This monthly amount, further divided by the Minnesota jurisdiction MWh sales, subject to the Fuel Clause Adjustment, yields the true-up per unit cost for each month. This per unit cost multiplied by the Fuel Adjustment Factor (FAF) ratio determines the proposed class true-up factors. The Company added the proposed class refund to the monthly Fuel Cost Charge (FCC) for each of nine months beginning April 1, 2026.<sup>15</sup>

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<sup>10</sup> Xcel's 24-63 FCA Compliance Report; at 5.

<sup>11</sup> Order Point 3 of the June 2019 Order in Docket No. E999/CI-03-802 states: "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."

<sup>12</sup> Xcel's 24-63 FCA Compliance True-Up Report; at 6.

<sup>13</sup> Xcel's March 31, 2026 Compliance Filing; at 1.

<sup>14</sup> Xcel's 24-63 FCA Compliance True-Up Report; at 6.

<sup>15</sup> Xcel's 24-63 FCA Compliance True-Up Report; at 7.

### 3. Variance Explanations

The Company noted that significant drivers for lower costs between the 2025 forecast and actual were:

- Lower than forecasted natural gas fuel prices.
- Lower generation of energy from Community Solar Gardens (CSG).
- Longer than forecast refueling outage at the Monticello Nuclear Generating Plant.

Table 2 below shows the comparison between actual results and the forecasts. The Company provided variance explanations for the primary components of fuel costs.

**Table 2: Comparison of Actual vs. Forecasted 2025 FCA Costs and Revenue (\$000)<sup>16</sup>**

	Actuals	Forecast	\$Variance	\$Variance
Coal	\$151,924	\$158,986	(\$7,062)	-4.4%
Wood/RDF	8,336	9,594	(1,258)	-13.1%
Natural Gas & Oil	172,336	261,161	(88,825)	-34.0%
Wind, Solar, Hydro	0	0	0	-
Nuclear Fuel	113,877	121,629	(7,752)	-6.4%
<b>Company-own Total</b>	<b>\$446,473</b>	<b>\$551,370</b>	<b>(\$104,897)</b>	<b>-19.0%</b>
Purchased Energy	\$337,794	\$219,137	\$118,657	54.1%
Purchased Energy (Solar)	52,112	55,498	(3,386)	-6.1%
Community Solar* Gardens	205,484	264,458	(58,974)	-22.3%
Purchase Energy (Wind)	212,239	217,934	(5,695)	-2.6%
MISO Market Charges	187,110	163,676	23,434	14.3%
<b>Purchased Power Total</b>	<b>\$994,739</b>	<b>\$920,703</b>	<b>\$74,036</b>	<b>8.0%</b>
<b>Total System Costs</b>	<b>\$1,441,212</b>	<b>\$1,472,073</b>	<b>(\$30,861)</b>	<b>-2.1%</b>
Less Sales Revenue	(\$307,174)	(\$256,708)	(\$50,466)	19.7%
Less Costs Direct Assigned	(158,234)	(230,867)	72,633	-31.5%
<b>Net system Costs</b>	<b>\$975,804</b>	<b>\$984,498</b>	<b>(\$8,694)</b>	<b>-0.9%</b>
MN Juris. Sales MWh	\$28,316,612	\$28,093,335	\$223,277	0.8%
RC & Wind Source MWh	(1,008,456)	(1,305,258)	296,802	-22.7%
<b>Net MN Sales MWh</b>	<b>\$27,308,156</b>	<b>\$26,788,077</b>	<b>\$520,079</b>	<b>1.9%</b>
MN FCA Cost	\$698,112	\$697,792	\$320	0.0%
CSG-Above Market Cost	134,439	184,921	(50,482)	-27.3%
Biomass Termination Costs	8,487	8,487	0	0.0%
St. Paul Cogeneration	439	0	439	N/A
Net CSG Cost Exclusion	2,246	0	2,246	N/A
SES Exemption	1,937	0	1,937	N/A
Land Sale Credits	(199)	0	(199)	N/A
Nuclear PTC	(83,059)	0	(83,059)	N/A
<b>Total MN Jurisdictional FCA Costs</b>	<b>\$762,402</b>	<b>\$891,200</b>	<b>(\$128,798)</b>	<b>-14.5%</b>
	<b>\$27.92</b>	<b>\$33.27</b>	<b>(\$5.35)</b>	
MN Jurisdictional Fuel Collections	907,646			
MN Jurisdictional Fuel Costs	762,402			
(Over)/Under Recovery	<b>(\$145,244)</b>			
Refund via Mid-year Rate Adjustment	(10,367)			
<b>Net (Over)/Under Recover</b>	<b>(134,877.00)</b>			

<sup>16</sup> Xcel's 24-63 FCA Compliance True-Up Report, Part A, Attachment 1.

### **a. Company-Owned Hydro Generation**

The Company-owned hydro generation forecast was based on a 30-year annual historical average of hydro generation for NSP System plants. There is no cost for hydro generation in the model because it is a fuel free resource.

Company-owned hydro facilities experienced lower than normal water flows in 2025, which resulted in less hydro generation than forecast. Less hydro generation than forecast increased generation from other fuel types.

### **b. Company-Owned Wind Generation**

To forecast wind generation, the forecast model incorporates individual hourly profiles of each NSP-owned project, based on historical data for projects with at least twelve months of operational data. For new projects that did not yet have annual data, the profiles were based on turbine technology, plant design, and localized weather data.

Actual 2025 Company-owned wind generation was lower than forecast primarily due to repowering at Pleasant Valley and Borders and to an outage at Courtenay. This was partially offset by less curtailment at Company owned facilities. There is no cost for wind generation in the model because it is a fuel free resource. Lower generation than forecast increases generation from other fuel types.

### **c. Company-Owned Coal Generation**

Coal prices are forecasted based on coal purchases under contract and rail contracts in effect at the time of filing. Any coal requirements that are not under contract are forecasted based on spot market prices. The coal forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the forecasted coal rates.

Actual coal generation was within one percent<sup>17</sup> of forecast, showing good alignment with forecast. Furthermore, realized coal and rail prices were lower than forecast, leading to 4.9 percent lower average cost/MWh of coal generation.

### **d. Company-Owned Wood/RDF Generation**

The wood/refuse-derived fuel (RDF) forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected plant conditions going forward are included in the forecasted wood/RDF rates.

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<sup>17</sup> Xcel's 24-63 FCA Compliance True-Up Report; at 8.

Actual 2025 Company-owned wood/RDF cost was lower than forecast due to lower fuel costs and higher credits for burning RDF at French Island than assumed in the forecast.

#### **e. Company-Owned Natural Gas Generation**

The Company-owned natural gas forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the natural gas forecast.

Natural gas fuel prices are forecast based on New York Mercantile Exchange (NYMEX) futures prices for natural gas at the Ventura hub. Costs for transport of natural gas to each specific plant are based on the Company's transport and delivery contracts in place at the time of its filing. The Company used natural gas futures prices in July 2024 in its Reply Comments forecast. The winter months of January, February, and December had lower actual natural gas prices, but for most of 2025, prices remained relatively close to the forecast. Natural gas prices were 8.2 percent<sup>18</sup> lower than forecast for the year.

Cost/MWh showed close agreement to forecast with a variance of less than 0.5 percent. Generation was significantly below forecast, driven by the generator failure at Riverside and an outage at Black Dog that was longer than assumed in the forecast.

#### **f. Company-Owned Nuclear Generation**

Company-owned nuclear forecast includes key modeling parameters, such as monthly operating capacity, based on the capability of each individual unit. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected conditions going forward, are included in the forecasted nuclear rates. Forecasted nuclear fuel price is based on the Company's existing nuclear fuel contracts at the time the forecast was filed.

Actual Company-owned nuclear generation was less than forecast in 2025 primarily due to the longer than forecast refueling outage at the Monticello Nuclear Generating Plant. Cost/MWh showed good agreement to forecast with a variance of 2.4 percent.

#### **g. Purchased Natural Gas Generation**

The purchased natural gas forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants or according to terms specified in the individual Power Purchase Agreements (PPAs). Planned maintenance for each unit based on the overhaul schedule provided by the PPA counterparty, as well as forced outage rates based on

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<sup>18</sup> Xcel's 24-63 FCA Compliance True-Up Report; at 10.

historical data and expected plant conditions going forward, are included in the PPA natural gas forecast.

Xcel used natural gas futures prices in July 2024 in its Reply Comments forecast and showed generally good agreement with actual gas prices, as discussed in Section 3.e. above.

#### **h. Purchased Solar Generation (PPAs)**

Each solar PPA is modeled in the forecast with hourly profiles for each project. These profiles are based on historical results from projects with operational data, and prices are based on the terms of each contract. Actual 2025 PPA solar costs were slightly lower than forecast.

#### **i. Purchased Solar Generation (Community Solar Gardens)**

The Community Solar Gardens (CSG) program forecast includes expectations of future growth based on current applications for gardens seeking to participate in the program. The Company identified current projects to anticipate in-service dates and estimate project completion (in capacity) by month and year. Additionally, Xcel forecasted additional applications based on a three-year historical average (removing outliers) to help account for its future pipeline of projects. The program is modeled as one entity rather than individually by garden. The assumed price for the program is based on historical price data, incorporating the Applicable Retail Rate (ARR) and Value of Solar (VOS) vintage rates for projects forecasted to be in-service in 2025.

The market cost of energy from the solar gardens generation is determined based on the assumed locational marginal price (LMP) in the simulation. This cost is shared with all jurisdictions in the NSP system. The cost of the program above market is direct assigned to Minnesota customers. Costs for CSGs were lower than forecast due to lower generation from CSGs than assumed in Xcel's 2025 Reply Comments.

#### **j. Purchased Wind Generation**

The wind PPA forecast reflects the hourly profiles for each individual project. For existing PPAs, profiles are based on historical data. For new PPAs, the profiles are based on turbine technology, plant design, and localized weather data. The price for each wind PPA is based on the terms of each contract. Projects for which the Company can allow MISO to curtail output are modeled as curtailable projects, while those for which curtailment is not allowed are modeled as non-curtailable projects.

Actual purchased wind generation \$/MWh was lower than forecast because PPA wind generation was higher than forecast due to less curtailment for wind PPAs overall.

#### **k. Purchased Generation – Other**

PPAs that do not fit within one of the prior three categories (primarily small hydro PPAs, the

remaining biomass PPA, and the PPA with Manitoba Hydro), are modeled based on historical generation (for the small hydro PPAs) or according to their contract terms (for the biomass and Manitoba Hydro PPAs). Price is determined based on contract terms or based on historical prices with assumed escalation.

Actual 2025 costs for other purchased generation were higher than forecast due primarily to extension of the purchase agreement with St. Paul Cogeneration, LLC, which was not included in the Reply Comments forecast, as it was not known until after Xcel's Reply Comments were completed.

### I. Market Purchases and Sales

For forecasting purposes, the PLEXOS simulation can purchase energy from a simulated MISO market, if that source of supply results in lower cost than utilization of one of the NSP system dispatchable resources. Additionally, the model forecasts asset-based sales opportunities into the MISO market after system native requirements are fulfilled. This is done through an hourly dispatch simulation, based on projected hourly market prices that represent LMP for the NSP system. The sum of these quantities plus the MISO charges represents the equivalent MISO Day 2 and Day 3 costs for the Forecast. Actual MISO Day 2 and Day 3 activities showed a net cost as compared to net revenue for the forecast.

This was driven by greater volume and costs for purchases from the MISO market than forecast partially in response to generator outages at owned combined cycle plants. Moreover, incremental transmission loss costs and RSG/RNU costs were greater than forecast as shown in Table 2 below. Greater than forecast revenues from FTRs provided some offset to higher MISO costs as shown in Table 2. Congestion costs were closely aligned with the forecast, as shown in Table 3, demonstrating that the forecast methodology for congestion was reasonable.

**Table 3<sup>19</sup>**  
**2025 MISO Charge Type Forecast to Actuals (\$000s)**

Category	Actual	Forecast	Variance
Congestion	\$225,777	\$226,290	(\$513)
FTR	(\$118,776)	(\$77,727)	(\$41,049)
Incremental Transmission losses	\$63,500	\$9,198	\$54,302
RSG/RNU	\$18,855	\$8,895	\$9,959
ASM	(\$2,245)	(\$2,981)	\$736
<b>MISO Charges TOTAL</b>	<b>\$187,111</b>	<b>\$163,675</b>	<b>\$23,436</b>

Xcel provided additional MISO charge details in Part B and discussed system congestion in Part B, Attachment 1, and within the Company's wind curtailment report.

<sup>19</sup> Xcel's 24-63 FCA Compliance True-Up Report; 14.

Table 4 compares the forecast to actual Asset-Based Margins.

**Table 4**  
**Actual 2025 Asset-Based Margins (\$000s)**

	Revenue	Cost	Margin
<b>Forecast</b>	298.6	193.0	105.6
<b>Actuals</b>	307.2	199.3	107.9
<b>Variance</b>	8.6	6.3	2.3

### m. Retail Sales

The Minnesota sales forecast used in the 2025 Fuel Forecast was developed in March 2024. Actual Minnesota retail sales in 2025 were 28,316,612 MWh, compared with the 2025 sales forecast of 28,277,355 MWh, resulting in a sales-to-forecast variance of 89,259 MWh (0.3 percent).<sup>20</sup> As summarized in Table 5 below, contributing factors to the forecast variance include: 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. Taken together, weather impact was the largest contributor to the sales forecast variance.

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<sup>20</sup> Sales for the Renewable\*Connect program are excluded from these figures in the fuel clause mechanism.

**Table 5<sup>21</sup>**  
**Sales-to-Forecast Variance in 2025 (MWh)**

	2025 Minnesota Juris.
Spring 2024 Forecast of 2025 Sales	28,227,355
Actual 2025 Cal Month Sales	28,316,613
Actual Sales Variance from Forecast	89,259
<b>Contribution to Forecast Variance:</b>	
DSM Forecast Variance	61,302
C&I Load additions/reductions	<b>[PROTECTED DATA BEGINS</b>
	<b>PROTECTED DATA ENDS]</b>
2025 Weather Impact	209,727
	<b>[PROTECTED DATA BEGINS</b>
CHP Forecast Variance	<b>PROTECTED DATA ENDS]</b>
Solar Forecast Variance	68,494
Other Factors	-120,705
<b>Total</b>	<b>89,259</b>

**4. Other Items Impacting Total Fuel Cost and the Amount to be Returned to Customers**

**a. Solar Energy Standard Exclusion**

The Commission’s January 16, 2018 Order in Docket No. E-002/M-17-425 approved the Company’s plan for crediting Solar Energy Standard (SES)-related costs back to SES-exempt customers and to annually recover this amount from the Company’s customers through the riders, through which solar costs are charged.<sup>22</sup> The 2025 annual FCA recovery is shown in Part A, Attachment 2, line 47, the month the excluded customers were issued their bill credit.<sup>23</sup>

**b. Nuclear Production Tax Credits**

The Inflation Reduction Act of 2022 (IRA) created a new PTC for existing nuclear resources. Under the

<sup>21</sup> Xcel’s 24-63 FCA Compliance True-Up Report; at 16.

<sup>22</sup> The FCA and Renewable Development Fund (RDF) Riders.

<sup>23</sup> The Company provided this amount in the June 1, 2025 SES Exclusion Annual Report filed in Docket No. E002/M-17-425.

IRA, beginning in 2024, nuclear facilities are eligible for base credits of 0.3 cents per kWh generated by existing facilities. This base credit is eligible to increase by a factor of five to 1.5 cents per kWh, provided certain prevailing wage requirements are met. The value of the credits is subject to a sliding scale based on the revenue generated by the nuclear facilities, measured based on the LMP of energy, with the value of the credit diminishing as the LMP rises. The Commission's July 17, 2023 Order in Docket No. E-002/GR-21-630 approved Xcel's proposal to include an NPTC tracker and refund in the Fuel Clause.<sup>24</sup>

The Minnesota allocated value of the NPTCs for 2025 is \$83.1 million,<sup>25</sup> inclusive of transaction costs. NPTCs in 2025 were less than in 2024 due to higher annual gross receipts in 2025. Xcel noted in its Fuel True-Up in Docket No. E-002/AA-23-153 that NPTCs and the applicable prevailing wage requirements were new in 2024; and as such, the Company was still working through the review and documentation process to ensure compliance with these requirements in its True-Up filing for 2024. Xcel believed then that there may be additional costs incurred to ensure compliance with the prevailing wage requirement, and indicated that final adjustments to the 2024 nuclear PTC value would be addressed in its Fuel Forecast True-Up Report for 2025 due by March 1, 2026.

Consequently, the Company now confirms that it incurred costs for consulting fees needed to adhere to the prevailing wage standards required to earn the NPTCs. These costs were not included in the 2024 True-Up, but Xcel stated that it now includes Minnesota's jurisdictional share of these costs incurred in 2025 to confirm the prevailing wage standards for NPTCs earned in 2024.<sup>26</sup> These costs are noted on line 55 of Part A, Attachment 2.

### c. Sherco 3 Replacement Power Costs Refund

In its June 5, 2025 Compliance filing in Docket Nos. E-999/AA-18-373, E-999/AA-17-492, E-999/AA-6-523, E-999/AA-14-579, E-002/GR-13-868, E-999/AA-13-599, E-002/GR-12-961, and E-002/AA-23-153 the Company confirmed that the Sherco Unit 3 replacement power cost refund had been issued as authorized by the Commission, all in one month, April 2025. Xcel included a refund of \$47,956,813, including interest of \$22,375,076, in the FCA applied to customer usage for April 2025. Because actual sales were higher than forecasted for April, the actual refund was \$51,061,965,<sup>27</sup> or \$3,105,152 higher than the refund obligation. Xcel included approximately \$3.1 million over-refunded in its true-up, reducing the total true-up refund amount.

### d. Land Sale Credits

The Commissions April 12, 2023 Order in Docket No. E-002/PA-23-110 and May 2, 2023 Order in Docket No. E-002/PA-23-118 approved the Company's proposal to credit the jurisdictional gains

<sup>24</sup> See Ordering Paragraph No. 113.

<sup>25</sup> Xcel's 24-63 FCA Compliance True-Up Report; at 17.

<sup>26</sup> *Id.*

<sup>27</sup> *Id.*; at 18.

related to sales of land in Becker Minnesota and in Red Wing, Minnesota respectively, to customers through the FCA. The gain credited to Minnesota customers for the Becker land sale was \$139,584,<sup>28</sup> and the gain credited to Minnesota customers for the Red Wing land sale was \$59,025. Xcel adjusted its January 2025 fuel rates to include credits related to the land sales.<sup>29</sup>

#### **e. Riverside Outage Update**

The Company noted that in its July 30, 2025 Reply Comments in Docket No. E002/AA-25-63, it discussed that the Riverside plant experienced an electric generator failure in April 2025. Xcel filed a Root Cause Analysis Report on September 19, 2025 in this docket, which concluded that the failure was caused by a manufacturing flaw. The Company reported that Riverside's electric generator experienced a catastrophic failure following the liberation of one of the generator's retaining rings. The event resulted in extensive damage to both the generator's field and stator. Xcel Energy initially partnered with Siemens Energy to identify a suitable used replacement generator. After evaluating multiple options, Xcel Energy determined that no viable replacement unit was available.

Subsequently, the generator's original equipment manufacturer (OEM), Ethos Energy, was contracted to perform detailed engineering assessments and execute the required repairs. Following inspection of the stator, field, and end bells, Ethos developed a repair-based recovery approach rather than replacement. The generator field has been transported to Ethos Energy's shop, where engineering design work is underway and long-lead materials are being procured. Copper and other critical materials required for field and stator repairs have extended procurement timelines, contributing to the overall outage duration.

Xcel is pursuing an insurance claim to cover the cost to replace the generator. The Company is continuing to assess whether it will file any other third-party claims.

The Riverside outage contributed to less natural gas costs than forecast, as driven by a lower than forecast volume of natural gas combined cycle generation. However, as discussed previously, much of the reduction in natural gas generation was offset through interactions with the MISO market.<sup>30</sup>

### **5. Other Compliance Items**

#### **a. Prairie Island Reactor Coolant Pumps Vendor Liability Update**

In compliance with Ordering Paragraph 4 of the Commission's August 7, 2025 Order in Docket No. E-002/AA-23-153, Xcel provided the following update related to the Reactor Coolant Pumps (RCPs) seal replacements at Prairie Island.

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<sup>28</sup> Xcel's 24-63 FCA Compliance True-up Report; at 18

<sup>29</sup> *Id.*

<sup>30</sup> *Id.*; at 19.

Xcel noted that during startup at the facility, both RCPs indicated high vibrations and one pump indicated seal leakage. Per plant procedure, both pumps were shut down and uncoupled for maintenance, which included seal replacement on one pump. Upon completion of maintenance and repair, the unit returned to service on January 17, 2025.<sup>31</sup> The vendor for the Prairie Island RCP seal replacements took partial responsibility for the issues requiring subsequent seal replacements. A settlement agreement reached with the vendor amended the contract for the work scope, with the vendor covering the cost of the second mobilization and replacement \$616,022 and providing a credit of \$100,000 to be applied to the 22 RCP seal replacement for the 2025 Prairie Island Unit 2 refueling outage.<sup>32</sup> The Company agreed to pay for the first mobilization and replacement at a cost of \$639,202; and has preserved all contractual and legal rights as part of the agreement.

The \$100,000 credit was applied to the scheduled work to replace the 22 RCP seals in the Fall of 2025 Prairie Island Unit 2 refueling outage. The \$616,022 credit was applied to the cost of the second mobilization and replacement in the Fall of 2024 Prairie Island Unit refueling outage. These two credits lowered overall costs that customers would pay for through base rates.

Table 6 provides Xcel's updated FCA rates per customer class, for 2024 & 2025 True-Ups, net of nuclear production tax credits and 2025 mid-year adjustment. Table 7 provides Fuel Clause Rates for C&I General Time of Use (TOU) Services Pilot.

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<sup>31</sup> Xcel's 24-63 FCA Compliance True-up Report; at 22.

<sup>32</sup> *Id.*

**Table 6: 2026 Monthly Fuel Clause Charges with 2024 & 2025 True-UPs, NPTCS & Mid-Year Adjustment (\$/kWh)<sup>33</sup>**

Month	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
January	\$0.01568	\$0.01566	\$0.01542	\$0.01959	\$0.01231	\$0.01179
February	\$0.01575	\$0.01574	\$0.01551	\$0.01971	\$0.01237	\$0.01184
March	\$0.01681	\$0.01679	\$0.01654	\$0.02102	\$0.01319	\$0.01263
April	\$0.02499	\$0.02497	\$0.02460	\$0.03124	\$0.01963	\$0.01880
May	\$0.02695	\$0.02693	\$0.02653	\$0.03369	\$0.02116	\$0.02027
June	\$0.02973	\$0.02971	\$0.02926	\$0.03719	\$0.02334	\$0.02234
July	\$0.02927	\$0.02924	\$0.02880	\$0.03661	\$0.02296	\$0.02197
August	\$0.02780	\$0.02778	\$0.02735	\$0.03477	\$0.02181	\$0.02087
September	\$0.02448	\$0.02445	\$0.02410	\$0.03061	\$0.01922	\$0.01840
October	\$0.02243	\$0.02242	\$0.02208	\$0.02805	\$0.01762	\$0.01687
November	\$0.01926	\$0.01925	\$0.01895	\$0.02408	\$0.01512	\$0.01448
December	\$0.02162	\$0.02159	\$0.02128	\$0.02703	\$0.01697	\$0.01624

<sup>33</sup> Xcel's 24-63 FCA Compliance True-up Report; Part A, Attachment 3.

**Table 7: 2025 Monthly Fuel Clause Rates for C&I General Time of Use Services Pilot (\$/kWh)<sup>34</sup>**

Month	Commercial & Industrial General TOU Service Pilot		
	Demand		
	Peak	Base	Off-Peak
January	\$0.02034	\$0.01640	\$0.00807
February	\$0.02045	\$0.01649	\$0.00810
March	\$0.02181	\$0.01759	\$0.00864
April	\$0.03242	\$0.02616	\$0.01287
May	\$0.03498	\$0.02821	\$0.01387
June	\$0.03860	\$0.03111	\$0.01528
July	\$0.03800	\$0.03063	\$0.01502
August	\$0.03609	\$0.02909	\$0.01427
September	\$0.03178	\$0.02562	\$0.01259
October	\$0.02911	\$0.02347	\$0.01155
November	\$0.02499	\$0.02015	\$0.00991
December	\$0.02805	\$0.02261	\$0.01112

### **b. Self-Commitment/Self-Scheduling Annual Report**

Xcel filed its 2025 Self-Commitment and Self-Scheduling Annual Report as Part G of the True-Up Report in the instant docket, as well as a stand-alone report in Docket No. E999/CI-19-704.<sup>35</sup>

### **c. Additional MISO Data**

The Commission's August 7, 2025 Order in Docket No. E002/AA-23-153 requires new compliance items for this report regarding MISO metrics, Auction Revenue Rights (ARRs), and Financial Transmission Rights (FTRs). Xcel included the required information in Part, Attachment 15 and 16 of the instant docket.<sup>36</sup>

## **B. Department – Comments**

The Department filed comments on Xcel's February 27, 2026 Annual True-up Compliance on April 15, 2026. The Department recommended approval of the Petition with modifications, which are reflected in the Department's analysis of the petition in the following sections.

<sup>34</sup> Xcel's 24-63 FCA Compliance True-up Report; Part A, Attachment 3.

<sup>35</sup> *Id.*; at 23.

<sup>36</sup> *Id.*

## 1. Xcel Annual FCA History

Table 8 contains Xcel's approved forecasts, actual costs, and recoveries in each year since 2021, under the annual FCA process.

**Department Table 8<sup>37</sup>**  
**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			
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 table shows that, except in 2021 when Xcel under-recovered costs due to actual costs exceeding forecast, the Company has over-recovered costs and subsequently refunded ratepayers.

## 2. Summary of the True-Up Petition in the Current Docket

The 2025 true-up Petition shows a materially favorable fuel cost variance but an 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 MISO charges, especially incremental transmission losses and uplift-related charges, and by outage-driven market purchases.

The Department noted that Xcel's 2025 True-Up Petition requested 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.<sup>38</sup> This true-up filing will 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.

The cost and offsetting credit/revenue components of the Company's actual and forecasted fuel and

<sup>37</sup> Xcel's 24-63 FCA, Department's Comments; at 6.

<sup>38</sup> *Id.*; at 11.

purchased power costs recoverable through the FCA are broken into several major categories, as summarized in Department Table 3 and Table 2 of the current briefing papers.

The results shown in the referenced Tables point to a favorable fuel-cost variance and a substantially unfavorable MISO settlement variance, as discussed in section 2 above.<sup>39</sup>

### 3. Department Analysis

#### 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.<sup>40</sup>

The Company attributed much of this shortfall to the Riverside generator failure and to a longer-than-assumed outage at Black Dog. Xcel's actual costs for purchased natural gas generation (gas PPAs) were \$136.5 million, 1.2% (\$1.6 million), slightly lower than forecasted.<sup>41</sup>

Upon completion of its review, the Department concluded that Xcel has reasonably explained the variances between actual and forecasted natural gas costs.

#### 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.<sup>42</sup> 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.<sup>43</sup>

The Department concluded that 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.

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<sup>39</sup> Xcel's 24-63 FCA Compliance True-Up Report; at 4 and 5.

<sup>40</sup> Xcel's 24-63 FCA Compliance True-Up Report; at 9 and 10.

<sup>41</sup> *Id.*; at 11.

<sup>42</sup> *Id.*; at 12.

<sup>43</sup> Xcel's response to DOC IR No.42, see Attachment 1.

### **c. Coal**

After reviewing the actual 2025 Company-owned coal generation costs, the Department concluded that 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**

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.

In its August 7, 2025 Order in Docket No. E-002/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.

Based on its review of Xcel's report, the Department does not object to Xcel's explanation of the 2025 nuclear variance and concluded that Xcel has complied with the additional Prairie Island vendor liability reporting requirement established in Docket No. E-002/AA-23-153.<sup>44</sup> The Department requested 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. E-002/GR-24-320.

#### **i. 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. Xcel proposed returning \$83.1 million in credits to customers, less transaction costs, in 2025. The Company explained that NPTCs in 2025 were significantly lower than in 2024 (\$175.8 million) due to higher annual gross receipts in 2025.<sup>45</sup> The Department reviewed the calculations provided by Xcel and supported refunding \$83.1 million in nuclear PTCs.

### **e. Non-nuclear Generation outages**

#### **i. Non-Nuclear Unplanned Outages**

The Department provided a summary of Xcel's 2025 actual versus forecasted unplanned outages as Trade Secret data. The Commission's November 9, 2023 Order in Docket No. E-002/AA-23-153,

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<sup>44</sup> Xcel's 24-63 FCA, Department's Comments; at 15.

<sup>45</sup> *Id.*

required Xcel to report the following in future FCA true-ups: prudence of its management of unplanned outages at Sherco 1, King, and Sherco 3 in Xcel's next FCA true-up petition. The Company provided information related to this requirement in Part C, Attachment 3, page 3.<sup>46</sup>

The Department did 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 expressed more concern with Xcel's responses regarding Sherco Unit 1 and Riverside,<sup>47</sup> as discussed below.

### ii. Sherco Unit 1 Outage

Given that Sherco Unit 1 is scheduled to retire on December 31, 2026, Xcel stated that 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 tube leaks, and that "managed decline" resulted in acceptance of additional risk for certain scrubber-module derates.<sup>48</sup> In response to Department 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.<sup>49</sup> Based on the December 31, 2026 retirement date, the Department finds Xcel's explanation reasonable.

### iii. Riverside Outage

The Department noted that Riverside presents the most significant outage issue in the current True-Up Petition. According to Xcel, Riverside suffered a catastrophic generator failure in April 2025 after liberation of a retaining ring caused extensive damage to the generator field and stator. The Company further reported that no viable used replacement unit was available. Hence, the Original Equipment Manufacturer (OEM) developed a repair-based recovery approach, and long-lead material procurement has extended the outage duration. Xcel is also pursuing an insurance claim and is continuing to assess whether it will file any additional third-party claims. The Company stated that its estimate of 2025 Riverside replacement power costs is a high-level, simplified estimate that remains subject to refinement. Xcel said that it would maintain the Riverside-related FCA amount in a deferred account if recovery is delayed.<sup>50</sup> The Department reported that the amount at issue for the Riverside outage is substantial for 2025 and 2026; estimated at approximately \$90 million.<sup>51</sup>

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<sup>46</sup> Xcel's 24-63 FCA, Department's Comments; at 16.

<sup>47</sup> *Id.*

<sup>48</sup> Xcel's response to DOC IR No. 48, see Attachment 2.

<sup>49</sup> Xcel's response to DOC IR No. 53, see Attachment 3.

<sup>50</sup> Xcel's 24-63 FCA, Department's Comments; at 17.

<sup>51</sup> *Id.*

Given that the present record is not sufficiently developed to determine the prudence and net customer impact of the Riverside outage, the Department recommended 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.<sup>52</sup>

#### iv. Planned Outage

The Department reviewed Xcel's planned outages, and although actual 2025 non-nuclear planned outages differed from forecast, did not identify objections to the outage-specific information provided. In response to Department 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.<sup>53</sup> 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 contended that customers should still bear the outage-related replacement power costs, because Xcel's vendor selection and oversight were reasonable under the circumstances.<sup>54</sup>

The Department does not consider Xcel's explanation for King Unit 1 outage unreasonable. However, because Xcel stated that it recovered approximately \$1.5 million from Siemens, the Department requested that Xcel explain in its Reply Comments whether that warranty recovery has already been flowed back to customers, and 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.

#### v. Outages and Maintenance

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 comparison to the generation maintenance budget from the utility's most recent rate case. The Company's true-up petition provides this information in Part C, Attachment 6.<sup>55</sup>

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.<sup>56</sup> The Department continues to strongly encourage Xcel to fully spend the amount of maintenance expense being recovered from rate payers in base rates.

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<sup>52</sup> Xcel's 24-63 FCA, Department's Comments; at 18.

<sup>53</sup> Xcel's response to DOC IR No. 44, see Attachment 6.

<sup>54</sup> Xcel's response to DOC IR No. 52, see Attachment 8.

<sup>55</sup> Xcel's 24-63 FCA, Department's Comments; at 19.

<sup>56</sup> Xcel's 24-63 FCA, True-Up Petition, Part C, Attachment 6.

## vi. Non-Nuclear Outages Conclusion

Based on its 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 did not recommend approval of the recovery of Riverside-related outage replacement power costs on the current record. The Department's recommendations related to the Riverside and King Unit 1 outages are presented above in sections iv and v respectively.

## f. Congestion

Congestion costs of \$225.8 million for 2025 were about the same as the forecast, \$226.3 million; although 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, helped significantly reduce the net congestion cost.<sup>57</sup>

In the August 7, 2025, Order in Docket No. E-002/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 (Ordering paragraphs 5 and 6).<sup>58</sup> The Department noted that in the 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 concluded that 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

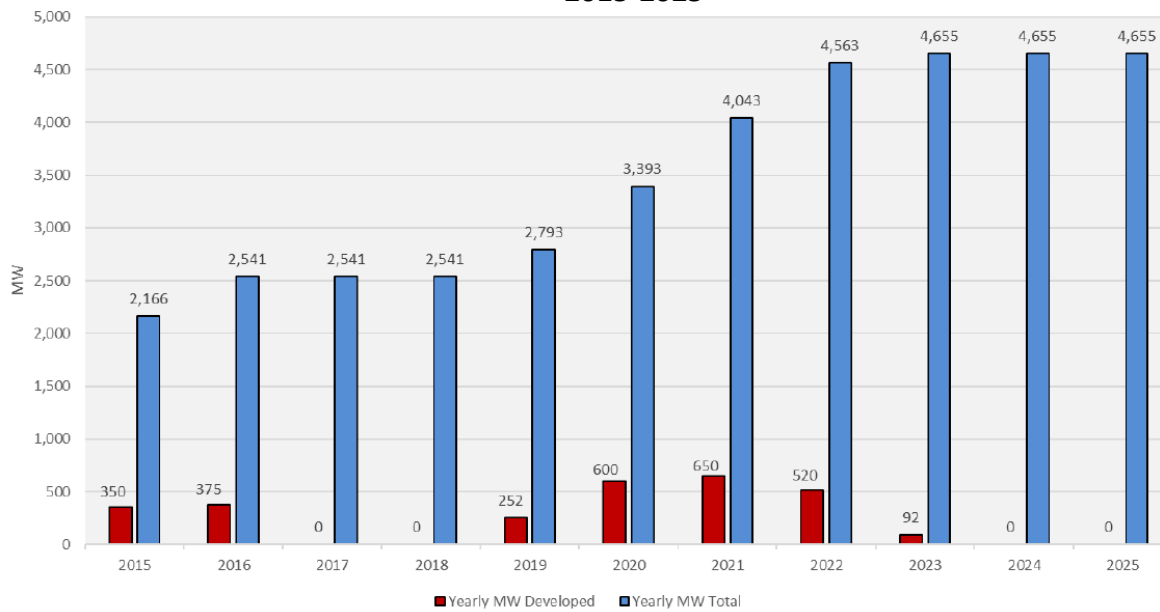
Prior to 2024, Xcel added significant wind capacity, as shown in Chart 1 below. The chart shows planned and installed Company-owned and PPA wind generation facilities on an incremental and cumulative basis.

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<sup>57</sup> Xcel's 24-63 FCA, Department's Comments; at 21.

<sup>58</sup> 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.

**Figure 1: NSP Wind Development (MW)  
2015-2025**



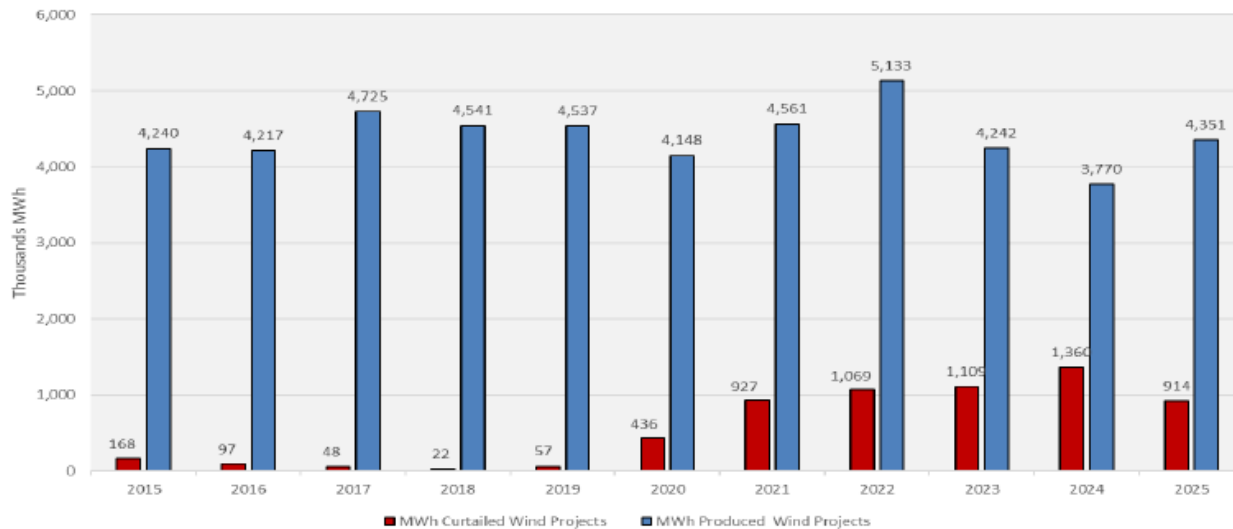
#### i. Wind PPAs

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.<sup>59</sup> 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.<sup>60</sup>

<sup>59</sup> Xcel's 24-63 FCA True-Up Petition, Part C, Attachment 1 at 18.

<sup>60</sup> Xcel's 24-63 FCA, Department's Comments; at 23.

**2015-2025**  
**Figure 2: NSP PPA Wind Production & Curtailment (MWh)**



## ii. Xcel-Owned Wind

Xcel-Owned wind production and curtailment decreased significantly from last year, while wind projects were also reduced.<sup>61</sup> The Commission’s November 9, 2023 Order in Docket No. E002/AA-23-153, 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.<sup>62</sup> Xcel provided this information in Part C, Attachment 2b of its true-up petition.

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.<sup>63</sup>

The Department concluded that 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.

<sup>61</sup> Xcel’s 24-63 FCA, Department’s Comments; at 23.

<sup>62</sup> 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 Ordering Paragraph 5.

<sup>63</sup> 2023 FCA True-Up Department Comments at 21-22.

#### **h. MISO Costs and Revenues**

The Department noted that the current FCA True-up Petition reflects a sharp adverse variance in MISO cost and revenue outcomes. 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.” Greater than forecast revenues from Financial Transmission Rights (FTRs) provided some offset to higher MISO costs.”<sup>64</sup>

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.<sup>65</sup>

Based on Xcel’s clarification provided in response to Department IR No. 51, the Department indicated that values presented in Xcel’s Table 2 may not represent a consistent forecast-versus-actual comparison. The Department found that the presentation on the ITL variance in Xcel’s Table 2 is not sufficiently transparent to allow the Commission to determine whether the variance reflects differences in actual transmission loss costs or differences in how the metric was defined. Consequently, the Department requested that Xcel provides the following clarifications in its Reply Comments: (1) How the \$39.8 million average system losses identified in response to Department 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**

Based on its review, the Department concluded that Xcel has reasonably explained this variance in its actual and forecasted retail sales and does not have any objections to the Company’s proposed final 2025 actual sales.

#### **j. Proposed True-Up**

Xcel has implemented \$10 million monthly refund for December 2025 to 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 to update the FCA rates reduces April-

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<sup>64</sup> Xcel’s 24-63 FCA, Department’s Comments; at 25.

<sup>65</sup> Xcel’s responses to DOC IR Nos 40 and 51, see Attachment 9 and 10.

December FCA rates by \$91.8 million in aggregate.<sup>66</sup>

### **k. General Reporting Requirements**

The Department found that Xcel Energy's Petition complied with the fuel clause requirements of Minnesota Rules 7825.2800 - 7825.2840 and Docket No. E-999/CI-03-802.

### **l. Department Recommendations**

Based on its analysis and information in the record, the Department recommended the Commission approve Xcel's 2025 FCA True-Up Petition with the following modifications:

- For the King Unit 1 outage, the Department requested 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 requested 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. E-002/GR-24-320.
- For the Riverside outage, the Department recommended 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 E-002/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 Department IR No. 51 is reflected in the forecast, if at all; and (2)

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<sup>66</sup> Xcel's 24-63 FCA, True-Up Petition; at 5-6 (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).

Provide a revised Table 2 that separately identifies actual ITL, other transmission-loss components, and total transmission-loss cost.

### **C. Xcel Energy – Reply Comments**

On May 1, 2026, Xcel filed Reply Comments to the Department’s April 15, 2025 Comments. In this Reply Comments, Xcel responded to the modifications to their True-Up proposed by the Department and provided additional information and clarification as requested.

#### **1. King Unit 1 Warranty Recovery**

The Department requested the Company explain in Reply Comments whether the \$1.5 million warranty recovery related to a 2025 planned outage extension at King Unit 1 has already been flowed back to customers. If so, where is that treatment reflected.

Xcel stated that following Siemens Energy’s completion of the King plant site work, as the Unit began start-up sequencing, it tripped and was forced offline. Subsequently, Xcel required Siemens Energy to return to the site to troubleshoot and fix the problem. Siemens Energy identified and resolved the issues. Pursuant to the warranty obligations in the vendor agreement, Siemens Energy paid for the cost of the additional work, and Xcel avoided the approximately \$1.5 million cost related to the repairs.

Xcel noted that there were no credits to flow back to customers, as the costs were not an obligation of the Company.

#### **2. Prairie Island Units 1 and 2 Refueling Outage Credits**

The Department requested the Company address in Reply Comments where the credits for the Prairie Island Units 1 and 2 refueling outage were reflected in base rates.

The Company noted that the 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.<sup>67</sup> Xcel asserted that since the credits were not received until 2025 after the rate case was filed, there are no relevant schedules or workpapers to provide from their pending rate case in Docket No. E-002/GR-24-320.

Xcel pointed out that the Commission has approved a capital project true-up process, as a customer protection mechanism in their past several rate case proceedings. Any capital project costs deviating from the budgeted costs in the rate case test year or plan years are reflected in that true-up mechanism, now filed annually on July 1. The Company insinuated that the Prairie Island Units 1 and 2 refueling outage credits will be reflected in the capital true-up for 2025.

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<sup>67</sup> Xcel’s 24-63 FCA Petition, Xcel’s Reply Comments; at 2.

### 3. Riverside Outage

The Department recommended 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 to develop a full record.

Xcel reasoned that since the outage remains ongoing, it is premature to send this matter to a contested case for a prudency review. At this point, not all replacement power costs are known, nor are total restoration costs. Additionally, the Riverside insurance claim adjustment is in the early stages; 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. As a result, the Company recommended that the Commission defers any decision on prudency or a contested case until after Riverside returns to service.

Xcel is willing to provide a final report within 90 days of Riverside returning to service, which will include an update on the scope of the outage, the status of the insurance claim adjustment, the status of any replacement power cost assessment, and any third-party claims.<sup>68</sup>

### 4. MISO Reporting and Transmission Loss Analysis

At the Department's request, Xcel provided a revised Xcel Table 2 that identifies actual Incremental Transmission Loss (ITL) cost as compared to forecast ITL from the 2025 Reply filing. Table 2-R below, provides an estimate of actual loss costs, labeled "Average System Transmission Losses," of \$39.81 million. This figure is calculated for 2025 by multiplying the hourly transmission loss volume from the MISO settlement statement, summed over the month by a monthly estimate of average system cost. The ITL is the difference between the total transmission loss costs derived from the MISO settlements for 2025 of \$63.5 million and the estimate of actual loss costs of \$39.81 million (= \$23.69 million).

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<sup>68</sup> Xcel's 24-63 FCA Petition, Xcel's Reply Comments; at 3.

**Table 2-R: MISO Charge Type Forecast to Actuals (\$000s)<sup>69</sup>**

Category	Actual	Forecast	Variance
Congestion	\$225,777	\$226,290	(\$514)
FTR	(\$118,776)	(\$77,727)	(\$41,049)
Incremental Transmission losses	\$23,690	\$9,198	\$14,492
RSG/RNU	\$18,855	\$8,895	\$9,959
ASM	(\$2,245)	(\$2,981)	\$736
<b>MISO Charges TOTAL</b>	<b>\$147,300</b>	<b>\$163,676</b>	<b>(\$16,376)</b>
Average System Transmission Losses	\$39,810	Embedded in PLEXOS production costs	

Note: Average System Transmission Losses + Incremental Transmission Losses = Total Claimed Losses  
 $\$39,810 + \$23,690 = \$63,500$  (from original Table 2)

The Company stated that an equivalent figure to actual “Average System Transmission Losses” cannot be shown for the forecast provided in the 2025 Reply filing for the following reasons:

1. Transmission and distribution (T+D) losses are embedded within the hourly MW load forecast input to the PLEXOS simulation. Costs for the T+D losses arise from additional generation costs for any and all generating units that PLEXOS commits and dispatches to meet the total MWh load forecast, inclusive of the T+D losses. The forecast generation costs to serve T+D losses cannot be separated from the generation costs required to serve the underlying customer load because the load is a single hourly MW input that is not separated between load at the customer meter and T+D losses.
2. The losses from the MISO settlement are only for transmission losses, not for distribution losses. The PLEXOS simulation includes losses for both transmission and distribution and cannot be separated as described above. Therefore, a direct comparison to actual transmission loss costs from the MISO settlement cannot be made.

## 5. Conclusion

Xcel stated that through its Reply Comments, it provided updated and additional information in response to questions raised by the Department; and requested approval of its 2025 Fuel Forecast True-Up as originally proposed.

### D. Department – Response to Reply Comment

The Department filed a response on May 15, 2026 to the Company’s May 1, 2026 Reply Comments. In its response comments, the Department recommended approval of the Petition with

<sup>69</sup> Xcel’s 24-63 FCA Petition, Xcel’s Reply Comments; 4.

modifications.

### **1. King Unit 1 Warranty Recovery**

After reviewing Xcel's reply to its request, the Department recommended no further action regarding the King Unit 1 warranty issue in this docket.

### **2. Prairie Island Units 1 and 2 Refueling Outage Credits**

Upon reviewing Xcel's reply, the Department recommended that since the credits have not been reflected in a filed true-up, that the Commission require Xcel, in the July 1, 2026 rate case capital projects true-up filing that reflects 2025 actuals, to separately identify the Prairie Island Unit 1 and Unit 2 vendor credits, show the jurisdictional allocation and revenue requirement impact of those credits, and explain how customers receive the benefit of those amounts.

### **3. Riverside Outage**

In its Reply Comments, Xcel opposed immediate referral to a contested case; given that the Riverside outage remains ongoing. The Company recommended the Commission defer any decision on prudence or a contested case until after Riverside returns to service. The Department disagreed with this recommendation.

The Department asserted that the key issue is whether Xcel's actions and decisions before and after the Riverside failure were prudent, based on the information known or that should have been known. Furthermore, deferring all reviews until Riverside returns to service would delay the engineering and prudent inquiry, risk the loss of timely factual development, and prolong uncertainty over whether customers should bear Riverside-related replacement power costs. Consequently, the Department maintains its position for referral to a contested case sooner. Additionally, the Department requested that the Commission approve the Department's request to seek authorization to incur costs for any specialized services required to assist in this matter under Minn. Stat. § 216B.62.<sup>70</sup> It would allow the Department to retain and rely on an independent outside engineering consultant to evaluate technical issues that cannot be fully assessed through accounting or financial review alone.

The Department recommended the Commission refers the Riverside issue to contested case and direct that the proceeding be structured in stages. The first stage would address engineering causation and prudence, including whether Xcel reasonably operated, inspected, maintained, and managed Riverside before and after the failure. A later stage, or supplemental record after Xcel's final report, would address final replacement power cost quantification, insurance proceeds, third-party recoveries, capacity-related impacts, customer-crediting treatment, and any refund or disallowance.

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<sup>70</sup> Xcel's 24-63 FCA Petition, Department's Response to Reply Comments; at 3.

Alternatively, if the Commission determines that the contested-case review should not proceed until additional outage information is available, the Department recommended that the Commission determine now that a contested case is warranted for the Riverside Plant outage, given its magnitude and complexity, but delaying initiation of the proceeding until after Xcel files its final outage report within 90 days of Riverside's return to service.

#### **4. MISO Reporting and Transmission Loss Analysis**

In its April 15, 2026 Comments, the Department raised concerns regarding Xcel's presentation of MISO transmission loss costs. The Department noted that Xcel's Table 2 appeared to compare forecast incremental transmission losses (ITL) to actual total transmission loss costs, which included both ITL and average system transmission losses.

In Reply Comments, Xcel provided a revised table showing actual ITL of approximately \$23.69 million, compared to forecast ITL of approximately \$9.198 million. Xcel also identified approximately \$39.81 million of actual average system transmission losses.

The Department did not recommend disallowance of the approximately \$39.81 million average system transmission loss amount on the current record. However, the Department stated that Xcel's Reply Comments confirmed that the original Table 2 was not sufficiently transparent. As a result, the Department recommended the Commission require Xcel to use the revised Table 2-R format, or an equivalent format, in future FCA true-up filings.

#### **5. Department Recommendations**

The Department continues to recommend that the Commission approve Xcel's 2025 FCA true-up Petition with modifications, as described below:

- Regarding the King 1 warrant issue, based on Xcel's explanation that the approximately \$1.5 million amount was an avoided cost rather than a refund or credit received by the Company, the Department does not recommend further action regarding the King Unit 1 warranty issue in this docket.
- Regarding Prairie Island Units 1 and 2 refueling outage credits, the Department recommended that the Commission require Xcel, in the July 1, 2026 rate case capital projects true-up filing that reflects 2025 actuals, to separately identify the Prairie Island Unit 1 and Unit 2 vendor credits, show the jurisdictional allocation and revenue-requirement impact of those credits, and explain how customers receive the benefit of those amounts.
- Regarding the Riverside Outage, the Department continued to recommend the Commission reserve the determination of prudence and recovery of Riverside-related replacement power costs and refer the Riverside issue to a contested case so that the record can be developed on

whether Xcel prudently operated, inspected, maintained, and managed Riverside before and after the outage, and whether any Xcel imprudence caused, contributed to, prolonged, or increased the costs of the outage. The Department also requested the Commission approve the Department's request to seek authorization to incur costs for any specialized services required to assist in this matter under Minn. Stat. § 216B.62. Alternatively, if the Commission determines that the contested-case review should not proceed until additional outage information is available, the Department recommended that the Commission now determine that a contested case is warranted for the Riverside Plant outage, given its magnitude and complexity, but delay initiating the proceeding until after Xcel files its final outage report within 90 days of Riverside's return to service.

During deliberations of the rate case, Docket No. E-002/GR-24-320, the Commission required the company to make a compliance filing within 90 days of the Riverside unit returning to operations, detailing a proposed process to address prudence along with recovery of unrecovered O&M expenses and any forfeited 2026 base rates related to Riverside. The filing shall include a detailed explanation of the incident and accounting supporting recovery.

- Regarding MISO reporting, the Department recommended the Commission require Xcel to use the revised Table 2-R format, or an equivalent format, in future FCA true-up filings to separately identify incremental transmission losses, average system transmission losses, total transmission losses, and the forecast treatment of losses embedded in PLEXOS.

#### **E. Staff Comments**

Staff agrees with the Department's recommendation to approve Xcel Energy's 2025 FCA true-up report, the 2025 fuel cost over-recovery refund of \$131.8 million, and the nuclear PTC refund of \$83.1 million. The Company has already implemented the refund process, submitted tariff sheets and agreed to adjust the true-up amount ordered by the Commission in this proceeding which would be implemented on September 1, 2026.

Regarding the Riverside Outage issue, Staff notes that the Department recommended the Commission refer the matter to a contested case so that the record can be developed. However, as described above, the Commission decided on this matter during the rate case deliberations.

#### **F. Decision Options**

1. Accept Xcel Energy's 2025 Fuel Forecast True Up Report. (Xcel Energy, Department)
2. Approve Xcel Energy's proposed refund of \$131.8 million for 2025 fuel cost over-recovery to Minnesota ratepayers. (Xcel Energy, Department)
3. Approve Xcel Energy's proposed refund of \$83.1 million for nuclear production tax credits to

Minnesota ratepayers. (Xcel Energy, Department)

4. Refer the Riverside Plant outage/replacement power costs issue to a contested case, so that the record can be developed on whether Xcel prudently operated, inspected, maintained, and managed Riverside. (Department)

**Or**

5. Determine that a contested case is warranted for the Riverside Plant outage, but delay initiating the proceeding until after Xcel files its final outage report within 90 days of Riverside's return to service. (Department, Xcel Energy)

**Or**

6. Do not refer the Riverside Plant outage/replacement power costs issue to a contested case, and defer any decision on prudence until after Riverside returns to service. (Xcel Energy)
7. Approve the Department's request to seek authorization to incur costs for any specialized services required to assist in the Riverside Plant outage matter under Minn. Stat. § 216B.62. (Department)
8. Require Xcel to use the revised Table 2-R format in this docket, or an equivalent format in future FCA true-up filings to separately identify incremental transmission losses, average system transmission losses, total transmission losses, and the forecast treatment of losses embedded in PLEXOS. (Department)
9. Require Xcel to separately identify the Prairie Island Unit 1 and Unit 2 vendor credits, show the jurisdictional allocation and revenue requirement impact of those credits, and explain how customers receive the benefit of those amounts in its July 1, 2026 rate case capital projects true-up filing. (Department)