MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**July 2, 2026**	**Agenda Item 3***
Company	**Minnesota Power**	
Docket No.	**E-015/AA-24-64**	
	In the Matter of Minnesota Power's Petition for Approval of the Annual Forecast of Automatic Adjustment Charges for the period of January 2025 through December 2025.	
Issues	Should the Commission approve Minnesota Power's Annual Forecast of Automatic Adjustment Charges for the period: January 2025 through December 2025?	

Staff Andrew Larson andrew.m.larson@state.mn.us 651-201-2259

✓ **Relevant Documents**	**Date**
Minnesota Power – Initial 2025 Petition (Public and Trade Secret)	March 2, 2026
Department of Commerce – Comments (Public and Trade Secret)	April 15, 2026
Minnesota Power – Reply Comments	May 1, 2026
Department of Commerce – Response to Reply Comments	May 12, 2026
Public Utility Commission – Information Request 1	June 10, 2026
Minnesota Power – Response to Information Request 1	June 12, 2026

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I. Background

On March 2, 2026, Minnesota Power (MP or the Company) filed its annual automatic adjustment charges true-up report of forecasted fuel and purchased energy rates for the period of January 2025 through December 2025.

On April 15, 2026, the Minnesota Department of Commerce – Division of Energy Resources (Department) filed comments recommending approval and requesting that MP provide its 2025 true-up factor and supporting calculations.

On May 1, 2026, Minnesota Power filed Reply Comments providing the requested information.

On May 12, 2026, the Department filed a Letter recommending approval of MP's 2025 FCA True-up Petition.

II. Parties' Discussion

A. Minnesota Power – Initial 2025 Forecast

1. 2025 Fuel Forecast to Actuals

Actual sales and fuel costs were lower than forecast, thus resulting in higher per MWh costs, which also resulted in a total under collected amount of $3.9 million in fuel costs for 2025.[1] Minnesota Power's 2023 refund, which was applied from September 1, 2024 through August 31, 2025, resulted in a remaining under-refunded balance of $504,765. Thus, the net balance to be collected over the 12-month period beginning September 1, 2026 is estimated to be $3.5 million.

Several factors caused the swing to a refund balance for 2025. First, MISO market purchase prices increased due to a 20percent increase in actual 2025 Locational Market Prices (LMPs) compared to forecast, which is also about 59 percent higher than 2024 LMPs.[2] Second, 2025 wind and hydroelectric generation were unfavorable to forecast, necessitating the substitution of more expensive market purchases and Company generation. Finally, actual sales were weak compared to forecast, declining about 9 percent in 2025 due to reductions in Large Power mining sales. Total fuel costs were also slightly below forecast; however, on a per MWh unit basis actual fuel costs were 2 percent higher, thus contributing to the under-collection. Table 1 summarizes variances in fuel cost.

[1] Minnesota Power Initial Filing at 2.

[2] *Id.* at 22.

Table 1: Fuel Cost Summary[3]

	2025 Forecast	2025 Actual	Difference
Company's Generating Stations	$131,822,689	$135,562,244	$3,739,555
Plus: Purchased Energy	$228,880,278	$245,300,420	$16,420,143
Plus: MISO Charges	$39,304,154	$42,415,048	$3,110,894
Plus: Reagent Expenses	$4,925,978	$4,927,028	$1,050
Plus: NOx Charges	$0	$0	$0
Less: MISO Schedules 16, 17 & 24	$(306,699)	$(840,768)	$(534,069)
Less: Fuel Cost Recovered through Inter System Sales	$132,433,585	$176,631,581	$44,197,995
Less: Costs Related to Solar	$2,597,139	$2,199,704	$(397,436)
Plus: Time of Generation and Solar Energy Adjustment	$1,387,347	$2,242,109	$854,762
Total Cost of Fuel	**$271,596,420**[4]	**$252,456,333**	**$(19,140,087)**
Total Fuel Clause Sales (MWhs)	**8,997,900**	**8,192,436**	**(805,464)**
Average Cost of Fuel	**$30.18**	**$30.82**	**$0.63**

a) Sales

Calendar year 2025 actual sales were 8,192,436 MWh compared to the forecast of 8,997,900 MWh, a decrease of 805,464 MWh, or 9 percent.[5] Sales variances were unfavorable for the Residential, Commercial, Large Power Taconite, Large Power Paper and Pulp, Large Power Pipeline, and Other Miscellaneous, with Large Power Taconite registering by far the greatest decline in sales. Only Municipals showed a modest gain in sales. Although Inter System sales increased, they represent non-Fuel Clause Adjustment (FAC) sales and thus are removed. Table 2 summarizes MP's 2025 actual and forecasted sales.

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[3] Minnesota Power Initial Filing at 22.

[4] Approved by Commission Order dated November 8, 2024 in Docket No. E015/AA-24-64, and November 25, 2024 in Docket No. E015.GR-23-155.

[5] Minnesota Power Petition at 23.

Table 2: Sales Comparison[6]

2025 Sales (MWh)	Forecasted Sales	Actual Sales	Difference
Total Sales of Electricity	**12,710,739**	**12,619,493**	**(91,246)**
Residential	1,040,641	1,014,950	(25,691)
Commercial	1,202,801	1,157,055	(45,746)
Large Power Taconite	4,190,960	3,462,018	(728,942)
Large Power Paper and Pulp	601,791	566,135	(35,656)
Large Power Pipeline	321,073	319,824	(1,249)
Other Miscellaneous	318,858	315,888	(2,970)
Municipals	1,378,882	1,406,168	27,286
Inter System Sales	3,655,733	4,377,457	721,724
Less: Inter System Sales	**3,655,733**	**4,377,457**	**721,724**
Customer Intersystem Sales	1,011,240	907,534	(103,706)
Market Sales	2,640,408	3,107,070	466,662
Station Service	4,085	4,833	748
Sales due to Retail and Resale Loss of Load	-	358,020	358,020
Less: Solar Generation & Purchases	**57,106**	**49,601**	**(7,505)**
Total Fuel Clause Sales	**8,997,900**	**8,192,436**	**(805,464)**

b) Generation

MP realized a decrease in generation in 2025 due to unfavorable variances in wind and hydroelectric production compared to forecast.[7] Wind generation was below forecast due to lower wind production. Lower hydroelectric generation was due to a continued drought in northern Minnesota in 2025. Thermal generation, however, was favorable to forecast due to higher market prices, transmission outages, and a reduction in MISO market imports, resulting in the dispatch of higher-priced generation in MP's region.

c) MISO Market Pricing and Congestion

The MISO market experienced a significant trend shift from lower priced and lower volatility markets in 2023 and 2024 to higher priced and more volatile markets in 2025, as shown in Trade Secret average market prices experienced by MP.[8]

d) Efforts to Control Congestion Costs

<u>Short-Term</u>[9]
MP will continue to optimize usage of its HVDC transmission line to cost-effectively deliver its 600 MW nameplate capacity wind portfolio in North Dakota to its customers. The HVDC line works to

[6] Minnesota Power Petition at 23.
[7] *Id.* at 23-24.
[8] *Id.* at 24.
[9] *Id.* at 24-27.

hedge congestion costs for customers, much like what Financial Transmission Rights ("FTR") do. MP also planned to modernize its HVDC terminals, which have operated well beyond their 30-year life. This upgrade will reduce unplanned outages and bring cost savings to customers.

In another initiative, MP, along with other Minnesota utilities and MISO, will seek transmission-related projects that can reduce the cost of grid congestion. As part of this initiative, MP has entered a contract with New Grid, a consulting firm which identifies system congestion events that affect MP's fuel costs. New Grid makes recommendations to reconfigure MP's transmission network as it exists today. The recommendations would be presented to transmission owners in the hope that they would adopt the reconfiguration recommendations. Another contributing factor was the advanced lead time needed to mitigate congestion in the case of known, future outages. However, in MP's case, the transmission owner did not take any action due to these complexities. Therefore, MP did not extend the contract in 2025.

There remains a misalignment of the cost recovery and benefit for New Grid services since the contract was not renewed. MP believed that if it engages again with New Grid and demonstrates benefits, the Company could consider a petition to recover costs.

In 2023 MP participated in another study with Grid North Partners, a joint initiative of utilities in Minnesota, Wisconsin, South Dakota, and North Dakota, to develop near-term solutions to incrementally resolve congestion. The Partners identified 19 congestion relief solutions with a cost of $130 million and a greater than 2:1 benefit to cost ratio. In-service dates conclude in 2026. In part, due to the success of the 2023 study, a legislative requirement of the State of Minnesota was enacted that requires transmission owners within the state to conduct similar studies. This study was completed in 2025.

Based on the results of the 2023 study, MP decided to develop ambient-adjusted line ratings, which are calculated using actual ambient temperatures instead of default seasonal temperature assumptions.

Medium-Term[10]

In 2025, Grid North Partners conducted another study to identify Grid Enhancing Technologies ("GETs") to address congestion in Minnesota. The study examined the previous three-year history of congestion and then forecasted congestion for 2026 and 2030. The study recommended the application of dynamic line ratings, a process that may require additional upgrades to other limiting equipment. MP planned to implement a targeted deployment of dynamic line ratings in 2026 that will include several facilities included in the GET report.

Additionally, MP anticipated reduced congestion as part of FERC Order 881 compliance, which requires all transmission owners to use ambient line ratings as the basis for evaluating near-term transmission service. The final implementation date is December 31, 2028. More renewable energy will be allowed to over congested lines resulting in lower congestion costs. MP's work with the

[10] Minnesota Power Petition at 28.

group continues.

Long-Term[11]

MP continued to work with MISO on Long Range Transmission ("LRTP") projects. Several LRTP Tranche 1 and Tranche 2.1 projects are near MP's territory. These projects will improve outage scheduling and outage management. Project benefit/cost ratios are expected to be more than 2:1.

In August 2023, MP and Great River Energy filed a Certificate of Need and Route Permit application for the Northland Reliability Project which the Commission approved in February 2025. The project is expected to provide $127 million to $2.1 billion in savings over the first twenty years by reducing congestion and providing access to lower cost generation.

In January 2026, MP and American Transmission Company applied for a Certificate of Need and Route Permit for the Iron Range – St. Louis County – Arrowhead (ISA) 345 kV Transmission Line Project, which MISO approved its LRTP Tranche 2.1 portfolio of projects. This project will enhance grid reliability in the Upper Midwest as grid operating conditions become more variable as demand grows for reliable clean energy in the Upper Midwest.

In January 2026, Minnesota Power, Otter Tail Power Company, and Great River Energy filed an application with the Commission for a Certificate of Need to build the Maple River – Cuyuna 345 kilovolt Transmission Project, a high-voltage transmission line that will stretch about 160-180 miles from Minnesota Power's Cuyuna Substation near Riverton, Minnesota, to Otter Tail Power Company's Maple River substation near Fargo, North Dakota. MISO approved the project as part of its LRTP Tranche 2.1 portfolio. The Project will provide additional transmission capacity and regional transfer capability to reliably integrate future generation resources.

Minnesota Power anticipated that congestion cost will be lower due to the LRTP projects being placed into service in the 2030-2033 timeframe. However, MP noted that the magnitude of congestion reduction can vary, especially if new wind and solar builds outpace the capability of new transmission in the area. Building new transmission to better distribute energy production from renewable rich regions will be needed to reduce congestion cost as Minnesota moves towards meeting the Carbon Free Standard.

2. Summary of Fuel Contracts

Minnesota Power has several Trade Secret agreements with various fuel and transportation suppliers.[12] Suppliers of coal include Kennecott Coal Sales LLC. (Montana), Arch Coal Sales (Wyoming), and Peabody Coal Sales (Wyoming).

Suppliers of biomass (wood fuel) for use at the Hibbard Renewable Energy Center include 15 suppliers, among whom are Savanna Pallets Inc. and McCabe Forest Products.

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[11] Minnesota Power Petition at 29-30.

[12] *Id.* at 8-10.

The Company maintains rail contracts with BNSF Railway.

Minnesota Power also receives natural gas for start-up, flame stabilization, and generation for its facilities.

3. Automatic Adjustment Charges[13]

This section provides detail on customer sales, MP generation costs, MP purchase costs, and Other Purchases. Intersystem sales are not included in the FCA.

Customer Sales

- Residential actuals were 2 percent lower than the 2025 forecast.

- Commercial actuals were 4 percent lower than the 2025 forecast.

- Large Power Taconite actuals were 17 percent less than the 2025 forecast. The taconite customers ran below forecasted levels due to an iron ore industry slowdown due to poor market conditions within the steelmaking industry.

- Paper and Pulp actuals were 6 percent less than the 2025 forecast. Sofidel's Duluth mill spent a significant portion of 2025 testing their newly acquired mill's capability to produce different paper products which resulted in large fluctuations in load at their facility month-to-month and lower average load than forecasted.

Generation Costs

Coal:
Boswell total costs were roughly 2 percent above forecast. The increase in total costs is due to Boswell 4 running higher in 2025 than what was forecasted. MP saw actual market prices come in around 20 percent higher than forecast and around 59 percent higher than 2024 which increased the output of Boswell. Boswell 4 cleared at higher levels by MISO due to the higher than forecasted market prices which increased their generation by about 10 percent compared to forecast. Boswell 3 had longer unplanned and planned outages throughout the year which resulted in less overall generation for 2025 by about 5 percent. When Boswell 3 was not on outage, the unit would have been cleared more and at higher levels due to the increase in LMPs for 2025. See Attachments 5 for an explanation of the Boswell 3 outages.

Gas:
Total Laskin costs were 41 percent higher than forecast. Laskin 1 generation was 76 percent more than forecast and Laskin 2 was 7 percent more than forecast in 2025. The biggest driver of the increase in generation was the increase in LMPs as discussed above. MP saw actual market prices

[13] Minnesota Power Petition, Attachment 2.

come in around 20 percent higher than forecast and around 59 percent higher than 2024 which would have resulted in Laskin being cleared by MISO more frequently than forecasted. Also, transmission outages and drought conditions in Canada resulted in higher priced generation being dispatched in our region.

Biofuel:
Total Hibbard costs were about 16 percent less than forecast due to the increase in fuel costs compared to forecast. Hibbard 3 fuel costs were 20 percent higher than forecast and Hibbard 4 fuel costs were 28 percent higher than forecast. With the increase in fuel costs compared to forecast, Hibbard would not have been cleared as often by MISO even though MP experienced higher LMPs in 2025.

Wind:
Wind generation came in about 8 percent lower than forecast with Bison being 8 percent below forecast and Tac Ridge coming in 2 percent below forecast. MP saw the greatest variances between forecast to actual wind generation across North Dakota in February – April 2025 and August - December 2025 which historically are higher wind generation months. Wind generation owned by MP has a $0 fuel cost.

Hydro:
Hydro generation in 2025 fell by about 30 percent compared to forecast. Drought conditions were present throughout 2025 which lowered Minnesota Power hydro generation. Hydro generation owned by MP has a $0 fuel cost.

<u>Purchase Power Market Costs</u>

Manitoba Hydro-Electric Board (Manitoba Hydro):
The Manitoba Hydro contract has a variable energy piece (133 Purchase Power Agreement) and throughout 2025, MP procured less energy from Manitoba Hydro than what was forecasted specifically in May – July 2025 due to drought conditions. The Manitoba Hydro fuel cost compared to forecast came in 6 percent above forecast due to increased LMPs in 2025 which were around 20 percent higher than forecast and around 59 percent higher than 2024.

Minnkota Power Cooperation Renewable Source:
Minnkota Power Cooperation Renewable Source costs came in 39 percent higher than forecast. The forecast is based on a contract. In 2024 after the 2025 forecast was filed, the MWs Minnesota Power purchased for the renewable source program increased which resulted in higher total costs in 2025. Purchases are offset by the sale to the renewable source customers on Attachment 1.3 “Inter-system Sales Forecast.”

Market Purchase:
MP saw a decrease in company generation (wind and hydro) which raised the MWhs purchased from the market to cover load. Also, Boswell 3 experienced more planned and unplanned outages in 2025 which decreased Boswell 3 generation for the year. See Attachment 5 for an explanation of the Boswell 3 outages.

The market purchase price per MWh came in 52 percent more than forecast due to the higher than forecasted MISO market prices in 2025 which were 20 percent above forecast.

Minnkota Power Station Service:
Costs came in 16 percent higher than forecast. The forecast is based on the prior year's monthly average.

Purchase to serve Non-Firm Retail Customer:
When the forecast was prepared, there was no purchase made so the MWhs were based on customer load.

The purchases to cover this Non-Firm Retail Customer were contracted with different counter parties and are included in the purchase by counterpart and is why actuals are showing 0 MWhs.

Counter Party Purchases: IMO/AEP/Shell/NextEra/HPU:

- Purchases that were not known or under contract at the time of the forecast filing but were procured during times when MP was short and needed to purchase energy to cover load. This can happen when generation is lower than expected, load is high, market prices are lower than expected, or MP has generating units off for outage.

- This section also includes the purchases that were procured to serve a Non-Firm Retail Customer.

Other Purchases:
The other purchases section includes all customer-owned generation purchases that are not forecasted.

<u>Purchased Power Wind</u>

Oliver County 1:
Oliver 1 costs came in 3 percent more than forecast. This higher cost was due to purchased MWhs coming in 9 percent higher than forecast even though the price was less than forecast by 6 percent. The lower price was due to credits received on the Oliver 1 invoices that were not forecasted and lowered the cost per MWh.

Oliver County 2:
Oliver 2 costs came in less than 1 percent higher than forecast. Purchased MWhs came in 4 percent higher than forecast and the price was less than forecast by 3 percent. The lower price was due to credits received on the Oliver 2 invoices that were not forecasted and lowered the cost per MWh.

Wing River:
Generation came in 65 percent lower than forecast and costs were 65 percent lower than forecast. Wing River was below forecast every month in 2025.

Nobles:
Nobles generation came in 1 percent more than forecast in 2025 and the cost per MWh was in line with the 2025 forecast.

Purchaser Power Solar

SES 20MW Solar:
Purchased MWhs were 14 percent less than forecasted and the $/MWh was 1 percent less than forecast. The
generation and costs go through the SEA (Solar Energy Adjustment)- See Attachment 2.4- SEA

Solar Subscription Cancellations:
MP did not forecast this source of supply as it is very small. When a customer leaves the program, MP will purchase from the customer any rolling balance due to solar generation.

Purchase to serve Municipal Solar Energy:
Purchase to procure solar energy for a municipal customer. Purchase is offset by the sale to the municipal customer on Attachment 2.3- Inter-system Sales

Purchased Power Square Butte:

The purchase is based on generation at Square Butte. Square Butte generation was lower in 2025 compared to forecast which reduced the MWhs purchased. Fuel costs were in line with the 2025 forecast.

4. Plant Outage Reporting[14]

MP experienced the following plant outages:

Boswell Unit 3 Bottom Ash System Blockage - Outage Date: 1/6/2025-1/15/2025

Plant ash hoppers became clogged with an excess amount of coal ash and slag, which exceeded the capacity of the ash removal system. The material began to overflow the hoppers and spilled into operation areas, creating unsafe conditions. After the unit was taken offline, contract labor worked seven days to remove the debris. Related equipment was inspected and repaired. Contributing factors were high sustained market demand, ambient temperatures, coal quality, and mechanical failures.

Number 3 and 4 Turbine Bearing Inspection Outage Date: 11/25/2025-12/4/2025

A maintenance outage was scheduled to inspect turbine bearings #3 and #4 after operating data indicated likely damage. Inspection confirmed that both bearings had experienced damage. Temporary modifications allowed the unit to return to service while replacement bearings are

[14] Minnesota Power Petition, Attachment 5.

planned for a future outage.

Tube Leaks - Thermal Fatigue[15]

Tube leaks are statistically the most common cause of outages in coal-fired power plants. Thermal fatigue is a common cause of tube leaks. Thermal fatigue manifests itself as cracking of the boiler tubes - sometimes as very small "micro" cracks and sometimes as large cracks. The cracks result from changing boiler temperatures, usually when the boiler swings up or down to follow load and when the boilers start up and shut down. This is a similar effect to bending a paper clip back and forth - after so many cycles it eventually breaks. Minimizing boiler “swings” by base loading helps minimize the impact of thermal fatigue. However, with the increasing impacts of intermittent wind generation, the Company is seeing more and more swings in output.

B. Department of Commerce – Comments

1. Prudency and Reasonableness

The Department reviewed MP’s Actual 2025 costs, noting the effect of market downturns in customer markets and high purchased power and LMP prices.[16] Generation outages necessitated the purchase of replacement power from the MISO market.

The Department also noted MP’s efforts to reduce congestion problems with ambient line ratings and MISO transmission projects.[17] In the longer term, the Department highlighted, MP expects to reduce congestion with additional transmission line connections.

The Department summarized MP’s FCA filing in Table 3 below. Sales were about 9 percent below forecast; recoverable costs were about 7 percent lower than forecast. Thus, fuel costs were about 2 percent higher than forecast.

Table 3: Comparison of Select Forecasted to Actual Data for MP’s 2025 Fuel Clause Adjustment True-up[18]

Data Description	2025 Forecast (A)	2025 Actual (B)	Dollar Difference (B-A)	Percentage Difference (B-A)/A
MWh Sales Subject to FPE	8,997,900	8,192,436	-805,464	-8.95%
Total Cost of Fuel/Purchased Power	$ 271,596,420	$ 252,456,333	$ (19,140,087)	-7.05%
Average Fuel/Purchased Power Cost per MWh	$ 0.18	$ 30.82	$ 0.64	2.12%

Table 4 below shows a detailed breakdown of fuel and purchased power costs. MP’s actual 2025 generation and purchased power costs were the two largest components of the total net power

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[15] The Department discusses thermal fatigue in its maintenance section below.

[16] Department Comments at 4-9.

[17] *Id.* at 6.

[18] *Id.*

costs. MISO market prices were 20 percent above forecast. These purchases covered outages and lower than forecast generation from wind and hydro. Generation at Boswell benefited from higher clearing price bids on MISO.

Table 4: MP's Forecasted and Actual 2025 Fuel and Purchased Power Costs and Offsetting Credits/Revenues by Major Category

Fuel/Purchased Power Cost, Credit, or Revenue Category	2025 Forecast (A)	2025 Actual (B)	Dollar Difference (B-A)	Percentage Difference (B-A)/A
Plant Generation Costs	$ 131,822,689	$ 135,562,244	$ 3,739,555	2.84%
Plus: Purchased Power Costs	$ 228,880,278	$ 245,300,420	$ 16,420,142	7.17%
Plus: MISO Charges	$ 39,304,154	$ 42,415,048	$ 3,110,894	7.91%
Plus: Reagent Expenses	$ 4,925,978	$ 4,927,028	$ 1,050	0.02%
Plus: NOx Charges	$ -	$ -	$ -	N/A
Less: MISO Schedule 16, 17, & 24	$ (306,699)	$ (840,768)	$ (534,069)	174.13%
Less: Fuel Cost Recovered through Inter System Sales	$ 132,433,585	$ 176,631,581	$ 44,197,996	33.37%
Less: Costs Related to Solar	$ 2,597,139	$ 2,199,704	$ (397,435)	-15.30%
Plus: Time of Generation and Solar Energy Adjustment	$ 1,387,347	$ 2,242,109	$ 854,762	61.61%
Initial Forecasted Cost of Fuel[28]	$ 266,372,540	$ -	$ -	N/A
Significant Events Filing	$ -	$ -	$ -	N/A
Total Cost of Fuel	$ 271,596,420	$ 252,456,333	$ (19,140,087)	-7.05%
Total FPE or FCA Sales (MWh)	$ 8,997,900	$ 8,192,436	$ (805,464)	-8.95%
Average Cost of Fuel	$ 30.18	$ 30.82	$ 0.64	2.12%

Table 5 reconciles the difference between forecasted and actual 2025 sales. The 0.72 percent unfavorable variance in sales was primarily due to decreased Large Taconite and Paper/Pulp sales. Inter System sales increased by 19.7 percent from forecasted sales but are not counted in the FAC. Based on MP's actual results, the Department concluded that it is reasonable that MP's actual FPE costs increased slightly above forecast. The Department noted that most of the causes of this variance, such as lower wind and hydro generation, were due to factors outside the Company's control.

Table 5: MP Sales Reconciliation Difference between Forecasted and Actual 2025 Sales[19]

2025 Sales (MWh)	Forecasted Sales (A)	Actual Sales (B)	Difference (B-A)	% Difference (B-A)/A
Total Sales of Electricity	**12,710,739**	**12,619,493**	**-91,246**	**-0.72%**
Residential	1,040,641	1,014,950	-25,691	-2.47%
Commercial	1,202,801	1,157,055	-45,746	-3.80%
Large Power Taconite	4,190,960	3,462,018	-728,942	-17.39%
Large Power Paper and Pulp	601,791	566,135	-35,656	-5.92%
Large Power Pipeline	321,073	319,824	-1,249	-0.39%
Other Miscellaneous	318,858	315,888	-2,970	-0.93%
Municipals	1,378,882	1,406,168	27,286	1.98%
Inter System Sales	**3,655,733**	**4,377,457**	**721,724**	**19.74%**
Customer intersystem Sales	1,011,240	907,534	-103,706	-10.26%
Market Sales	2,640,408	3,107,070	466,662	17.67%
Station Service	4,085	4,833	748	18.31%
Sales due to Retail and Resale Loss of Load	-	358,020	358,020	N/A
Less: Solar Generation & Purchases	**57,106**	**49,601**	**-7,505**	**-13.14%**
Total Fuel Clause Sales	**8,997,900**	**8,192,436**	**-805,464**	**-8.95%**

The Department recommended the Commission find MP's actual 2025 fuel and purchased power costs recoverable through the FCA were reasonable

2. 2025 Fuel Clause Adjustment True-up

MP requested a net true-up recovery of $3,468,780 in FCA under-collections for the reasons discussed above, with recovery spread over 12 months starting September 1, 2026. Additionally, the net over-collection from the 2023 true-up recovery in 2024 and 2025 is $504,765, minus a $711 small cancel rebill general ledger adjustment. Table 6 shows the net true up calculation.

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[19] Department Comments at 8.

Table 6: Over/(Under) Collection Calculation[20]

2025 Actual Collections from Customers	$ 206,422,619
Less: Actual Costs and Actual Sales	$ 210,395,453
Plus: 2023 True-Up Recovery Under-collection (2024)[38]	$ (125,171)
Plus: 2023 True-Up Recovery Overcollection (2025)[39]	$ 629,936
Plus: Small cancel rebill adjustments in General Ledger	$ (711)
Remaining Under Collection = Net 2025 FCA True-Up Amount	**$ (3,468,780)**

The Department found MP correctly calculated its 2025 FCA/FPE Rider under collection of $3,468,780. The Department considered the Company's proposal to recover the under collection from customers effective over the 12-month period beginning September 1, 2026, following Commission approval to be reasonable.

3. Compliance with Reporting Requirements

The Department verified that MP's Petition included the information required in Minnesota Rules 7825.2800 – 7825.2840 and as ordered in Docket No. E-999/CI-03-802. MP's filing included an explanation of why the forecasted rate differed from actual costs and why it is reasonable to credit ratepayers the difference.[21]

MP's filing also included the required Self-Commitment and Self-Scheduling Analysis Annual Compliance Filing of large base-load generators.[22]

The Department noted Order Points 4 and 5 of Commission's August 7, 2025 Order, in MP's 2024 FCA True-Up petition requires the Company to provide additional ARR/FTR information, as well as a list of strategies considered and implemented to address congestion and curtailment of energy.[23] The Department expected this to be addressed in MP's upcoming 2027 FCA Forecast filing on May 1, 2026.

a) Maintenance Expenses of Generation Plants and Correlation with Incremental Forced Outage Costs

The Commission required all electric utilities subject to automatic adjustment filing requirements, except for Dakota Electric, to include in future annual automatic adjustment filings the actual expenses pertaining to maintenance of generation plants, with a comparison to the generation

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[20] Department Comments at 9.

[21] Minnesota Power Petition at 22-31.

[22] *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities,* Docket No. E999/CI-19-704, Annual Compliance Filing, March 2, 2026.

[23] Docket No. E-015/AA-23-180

maintenance budget from the utility's most recent rate case.[24, 25]

This requirement stems from the drastic increase in investor-owned utilities (IOUs) outage costs during FYE06 and FYE07. When a plant experiences a forced outage, the utility must replace the megawatt hours the 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 outage costs incurred by investor-owned utilities in fiscal years 2006 and 2007 raised questions as to whether the utilities were (1) maintaining plants appropriately to prevent forced outages, and (2) 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 and to minimize the costs of scheduled outages through careful planning, prudent timing, and efficient completion of schedule work" (Order 06-1208, p. 5).

The Department compared MP's approved and actual generation maintenance expenses for 2025 and found them to be reasonable. Thermal power generation maintenance actual 2025 expenses were about $0.6 million lower than levels in rates. MP stated that FERC, per FERC Order 898, created FERC account 558 for the maintenance of wind and solar panels. The Department will monitor these maintenance accounts in future FPE filings.

The Department reviewed MP's incremental forced outage costs for 2025. Actual forced outage costs were $7,459,193 compared to the forecast of $3,452,777, mainly due to unplanned outages at Boswell Unit 3 and Unit 4. In the first incident, the bottom ash system became clogged due to multiple failures of the conveyer chain, leading to hopper overfilling and bridging.

In the next incident, bearings overheated and were damaged due to the failure in the motor suction pump leading to a loss of oil pressure during critical operation. The failure was not due to human error.

Third, in response to a Department Information Request (IR), MP stated that Boswell Unit 4 experienced thermal fatigue cracking in a superheat tube, resulting in a one-day unplanned outage in mid-February 2025. The Department stated that this instance was due to normal wear and tear.[26]

In the last incident, Unit 4 experienced a slag buildup in the reheat section of the boiler which restricted air flow through the boiler, causing a four-day outage. The Department stated that this instance was also due to normal wear and tear.

The Department found MP's explanations of true equipment failure to be reasonable. Thus, the Department accepted MP's forced outage costs for the 2025 true-up.

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24 Department Comments at 11-12.

25 *In the Matter of the Review of the 2006 Annual Automatic Adjustment of Charges for All Electric and Gas Utilities*, Minnesota Public Utilities Commission, Order, February 6, 2008, Docket No. E999/AA-06-1208, (eDockets) 4928266.

26 See MP's discussion of thermal tube fatigue in the Plant Outage Reporting section above.

b) Department Maintenance Recommendation

The Department concluded MP's Petition complies with the applicable reporting requirements. The Department recommended the Commission approve the compliance reporting portions of the Company's Petition.

4. Department Recommendation

Based on its review, the Department concluded (1) MP's actual fuel and purchased power costs for 2025 were reasonable and prudent, (2) MP correctly calculated its 2025 FCA/FPE Rider under collection of $3,972,834, (3) MP correctly calculated its total 2023 over-collected amount of $504,765, included in the 2025 FCA True-Up for a net total under-collection of $3,468,069, (4) MP to provide its 2025 true-up factor and supporting calculations, and (5) MP's Petition complies with the applicable reporting requirements.

Therefore, the Department recommended the Commission take the following actions:

- Find MP's actual 2025 fuel and purchased power costs recoverable through the FCA/FPE rider were reasonable for 2025.
- Find MP correctly calculated its 2025 FCA/FPE Rider net under-collection of $3,468,069.
- Allow MN Power to collect $3,468,069 in the 12-month period, beginning September 1, 2026, following approval by the Commission.
- Require MP to provide its 2025 true-up factor and supporting calculations in its reply comments.
- Approve the compliance reporting portions of MP's Petition.

C. Minnesota Power – Reply Comments

Minnesota Power responded to the Department's requested information.[27]

1. 2025 True-up Factor and Supporting Calculations

MP stated that the True-Up factor is calculated by dividing the True-Up amount of $3.5M by the applicable 2026 and 2027 sales to which the True-Up rate will apply.

Supporting calculations are provided in Attachment 1 – FAC Calculation 2025 – True Up Rates to the Reply Comments, which included detailed breakdowns of the true-up amount, forecasted sales, and the resulting factor. MP calculated the 2025 True-up factor as follows:[28]

[27] Minnesota Power Reply Comments.

[28] See Department Comments, Table 6 for related figures.

Table 7: Final True-Up Amount Calculation[29]

Remaining Under Collection – Net 2025 FCA True-Up Amount	$ 3,468,780
Less: Small cancel rebill adjustments in General Ledger	$ (711)
Final 2025 True-Up Factor	$ (3,468,069)

Table 8 shows Minnesota Power's proposed monthly forecasted rates to be implemented September 1, 2026.

Table 8: 2025 FAC True-up Cost of Fuel - (¢/kWh)[30]

Sep '26	Oct '26	Nov '26	Dec '26	Jan '27	Feb '27	Mar '27	Apr '27	May '27	Jun '27	Jul '27	Aug '27
4.8	4.7	4.5	4.2	4.7	5.1	4.9	5.3	5.3	5.4	5.0	5.1

2. Order Points 4 and 5 of the Commission's August 7, 2025 Order

MP acknowledged that the Department noted the Company had not provided information on Order Points 4 and 5 of Commission's August 7, 2025 Order in Minnesota Power's 2024 True-Up. These order points require the Company to provide additional ARR/FTR information, as well as a list of strategies considered and implemented to address congestion and curtailment of energy. The Company stated that it will be addressing these order points in the upcoming 2027 FCA Forecast filing on May 1, 2026 in Docket No. E015/AA-26-64.

D. Department Letter

The Department reviewed the Company's Reply Comments and Attachment 1, and has no further questions. The average FCA true-up cost of fuel is $0.045 (c/kWh) for September 2026 through December 2026, and $0.051 for January 2027 through August 2027. Based on its review, the Department concluded the 2025 true-up factor on Attachment 1 was correctly calculated. The Department also agreed with MP that the compliance information was correctly filed in MP's 2027 FCA Forecast filing on May 1, 2026 in Docket No. E015/AA-26-64. As a result, the Department recommended the Commission approve Minnesota Power's 2025 FCA True-Up Petition, and is available to answer any questions the Commission may have.

E. Commission Information Request 1

The Commission requested in Information Request 1 that MP provide the information stated in Ordering Paragraphs 4 and 5 of its Order in the 2024 FCA docket.[31] The Commission:

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[29] Department Comments at 9.

[30] Minnesota Power Reply Comments, Attachment 1.

[31] In the Matter of Minnesota Power's Petition for Approval of the Annual Forecast of Automatic Adjustment Charges for the Period of January 2024 through December 2024, docket E015/AA-23-180, Commission Order, Ordering paragraphs 4 and 5, August 7, 2025.

4. Required Minnesota Power, in its next annual filing, to provide the following information:

   a. A list of all segments eligible for Auction Revenue Rights (ARRs);

   b. A list of all segments for which ARRs were awarded;

   c. A list of all ARR segments converted to Financial Transmission Rights (FTRs);

   d. A comprehensive discussion of ARR nomination and FTR conversion strategies.

5. Required Minnesota Power, in its next annual filing, to provide the following information:

   a. A list of all the strategies Minnesota Power considered and implemented to address congestion and curtailment of energy. At a minimum, the list must include Grid Enhancing Technologies (e.g. Dynamic Line Rating, system reconfiguration, and system optimization), ARRs, FTRs, planning of transmission line projects to address congestion and curtailment within and between Regional Transmission Organizations, sequencing of transmission line outages, and sequencing of the construction schedule of pending transmission line projects; and

   b. A comprehensive discussion on the merit of each strategy and how Minnesota Power decides whether to implement each strategy. Minnesota Power must provide a cost-benefit analysis for each strategy or provide a justification for why a cost-benefit analysis cannot be performed.

F. MP Response to Information Request 1[32]

MP responded to Ordering paragraphs 4a, 4b, and 4c with Trade Secret information.[33]

MP responded to Ordering paragraph 4d, stating that its strategy for each transmission path is to determine whether to nominate the Auction Revenue Right (ARR) or to self-schedule (convert) the ARR to a Financial Transmission Right (FTR).[34] When the Company expects power to flow on a path from its generation to load, it will estimate the number of ARRs on that particular path to be converted to FTRs, given historical and projected line congestion and auction clearing prices. In the self-scheduling case, the cost or benefit of the FTR flows into the Company's MISO costs that are then allocated to MP's FAC.

When MP does not expect a specific transmission path to carry any of its power, it may nominate the path's ARR depending on historical and projected annual auction prices.[35] These ARRs have two outcomes. If the ARR is nominated, clears the annual auction positive (showing a gain), and is not converted to a FTR will result in a benefit that reduces MP's MISO costs. On the other hand, if

[32] Minnesota Power, Response to Commission Information Request 1, June 12, 2026.

[33] *Id.* at 2-16.

[34] *Id.* at 17.

[35] *Id.*

the ARR is nominated, clears the annual auction negative (showing a loss), and is not converted to a FTR will result in a loss that increases MP's MISO costs.

MP responded to Ordering paragraph 5a about controlling congestion costs with Trade Secret information on its short-term strategy.[36] In addition, the Company reviewed the rest of its short-term strategy, and its medium- and long-term strategies, which it had already discussed above in the section "Efforts to Control Congestion Costs."

Last, MP responded to Ordering paragraph 5b with Trade Secret information.[37]

G. Staff Comments

Staff notes that MP has commented on topics that may impact generation reliability, and, indirectly, affordability through the concept of cost causality. In its discussion of the Boswell coal generation unit shutdown, the Company described the problem of thermal metal fatigue on boiler tubes, which can lead to tube cracks, leaks and necessary repairs. Thermal fatigue is a function of the number of cool/hot boiler cycles a coal/steam unit experiences. The greater the number of cycles or swings, the greater the risk of thermal fatigue as the metal boiler tubes expand and contract. The introduction of intermittent wind generation in MP's generation portfolio may have increased the number of swings. Additionally, the cost causation principle states that if a cost driver, such as wind, is increasing the number of thermal fatigue repairs, then the cost driver should be assigned the related extra repair costs.

MP also commented on the relationship between the growth rates of new transmission capacity and new wind/solar generation. Although MP anticipates that congestion costs will be lower in the 2030-2033 period, the magnitude of future congestion reduction may vary if the growth of wind/solar generation outpaces the growth of transmission capacity.

H. Decision Options

1. Approve Minnesota Power's Annual Forecast of Automatic Adjustment Charges for the period: January, 2025 through December, 2025, subject to a subsequent true-up. (Minnesota Power, Department)

2. Require Minnesota Power to make a compliance filing with redlined and clean versions of the Fuel and Purchased Energy Rider Tariff sheet with supporting calculations, within 10 days of the date of the Order for implementation effective September 1, 2026. (Department)

[36] *Id.* at 17-20.

[37] *Id.* at 20-26.