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March 3, 2025

—Via Electronic Filing—

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

RE: ANNUAL TRUE-UP COMPLIANCE REPORT
2024 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES
DOCKET NO. E002/AA-23-153

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Annual True-Up and Compliance Report for the fuel forecast and monthly fuel cost charges approved for the 2024 calendar year. This Report also includes compliance items required to be included in the Company's Electric Annual Automatic Adjustment of Charges Reports and a proposal to begin a customer refund on April 1.

We note that Order Point 3[1] of the Commission's June 12, 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. The present refund proposal is submitted with 29 days' notice. We believe that, given the size of the refund, it is in the best interest of customers to begin the refund on April 1. The Company will implement the refund on April 1 if no objection is received prior to that date. We understand that implementation of new rates following the notice period remains subject to full Commission review within this docket.

Please note that portions of our Petition and attachments are marked as "Not Public." Certain data is considered to be "not public data" pursuant to Minn. Stat. §13.02, Subd. 9, and is "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as this data derives independent economic value, actual or potential, from not being

[1] Order Point 3 of the June 19, 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."

generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

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

Sincerely,

/s/

LISA R. PETERSON
DIRECTOR, REGULATORY PRICING AND ANALYSIS

Enclosures
cc: Service Lists

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2024 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-23-153

ANNUAL TRUE-UP REPORT

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission (Commission) this Annual Fuel Forecast True-Up Report which provides a comparison of the approved 2024 fuel forecast to 2024 actuals. This report is submitted in compliance with the various Orders issued in Docket No. E999/CI-03-802 which implemented Fuel Clause Reform and provides various other compliance items required to be filed in the Company's Electric Annual Automatic Adjustment of Charges Report (AAA).[1]

The Company's 2024 actual fuel expense was $894.7 million, or $128.1 million lower than our approved forecast of $1,022.7 million. The actual average fuel cost of $33.42 per MWh was 12.3 percent lower than the authorized rate of $38.10 per MWh. Actual fuel cost collections were $1,019.4 million, only 0.3 percent lower than forecast, corresponding to Minnesota jurisdictional sales that were 0.3 percent lower than forecast. In addition, the Company implemented a mid-year adjustment in November 2024 and refunded to customers $30.5 million before the end of the year, reducing the 2024 Minnesota fuel over-collection to $94.2 million.

The significant drivers for lower costs than our 2024 forecast were:

1. lower Community Solar Gardens (CSG) cost due to lower than forecast volume and average CSG rate;
2. lower congestion cost from the MISO market than forecast;
3. lower fuel cost for gas generation due to lower gas prices; and
4. lower fuel cost for coal generation due to reduced dispatch.

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[1] Orders dated December 17, 2017, December 12, 2018, and June 12, 2019.

In addition, we have made adjustments to refund to customers $176 million of nuclear production tax credit (PTC) transactions and $48 million related to the Sherco Unit 3 November 2011 outage replacement power costs,[2] which were not known at the time we filed our Reply forecast in July 2023. The adjustments made for these refunds comprise the majority of the amount to be returned to customers through the true-up. When those adjustments are included, the final 2024 amount to be returned to customers is $318 million. As noted above, fuel cost overcollection only for items included in the Reply forecast is $128.1 million, of which $30.5 million has already been refunded through our mid-year adjustment.

In this report, we provide details of the variance between forecast and actuals and discuss the prudency of our management of fuel costs in 2024. In addition, we discuss how we propose to return $318 million to customers.[3] Lastly, we provide various additional compliance reports.

2024 ANNUAL TRUE-UP REPORT

I. DESCRIPTION AND PURPOSE OF FILING

A. Background

On December 19, 2017, the Commission issued its ORDER APPROVING NEW ANNUAL FUEL CLAUSE ADJUSTMENT REQUIREMENTS AND SETTING FILING REQUIREMENTS in Docket No. E999/CI-03-802 (December 19 Order) which requires a utility's fuel rates to be set in a rate case or an annual fuel clause adjustment filing unless a utility can show a significant unforeseen impact. The Order specifies that these filings should include complete documentation supporting the proposed fuel rates, including information on Power Purchase Agreements (PPAs), estimates of costs for each type of fuel, and the proportion of each type of fuel, along with a complete description of any model used to develop the proposed dollars per MWh fuel rates, including but not limited to the identification and justification of the inputs and formulas used for all fuel types, and fully documented sales forecasts.

The December 19 Order also requires utilities to report annually the actual dollars per MWh fuel costs in each month by fuel type (including identification of costs from specific power purchase agreements) and compare the annual revenue based on the

[2] See Docket No. E999/AA-18-373, et al.
[3] We note that this amount accounts for $30.5 million already returned to customers in November and December 2024, though does not include the $15 million per month reduction included in January through March 2025 rates, as described in our September 30, 2024 rate adjustment filing in this docket.

fuel rates set by the Commission with annual revenues based on actual costs for the year. Each utility will refund any over-collections and show prudence of costs before allowing recovery of under-collections. 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. In this true-up report, the Company reports that the 2024 annual revenues collected were higher than total actual costs, and therefore we propose how to return over-collected costs to customers.

The Commission's December 12, 2018 Order in the same docket (December 12 Order) established January 1, 2020 as the implementation date for Fuel Clause Reform and also ordered that the forecast year be a calendar year. Each utility is required to file its Annual Fuel Forecast Petition in a separate docket.

The Commission's June 12, 2019 Order (June 2019 Order) in the same docket set forth a procedural schedule for the various filings, reviews, approvals, and implementation of the various components of the Annual Fuel Forecast process and approved the disposition of reporting items that are required to be included in Electric AAA Reports per Minn. Rules and past Commission Orders.[4]

The Commission's November 9, 2023 Order in Docket No. E002/AA-23-153 approved the Company's fuel forecast and revised monthly rate factors by customer class for calendar year 2024, including adjustments made for decisions in the recently concluded electric rate case in Docket No. E002/GR-21-630.[5] Several updates to the approved 2024 rates were made throughout the year. First, the Company's November 21, 2023 rate adjustment filing in Docket No. E002/AA-22-179 proposed to begin returning 2023 over-collected fuel costs to customers beginning January 1, 2024. Since no party objected, the Company implemented this adjustment as proposed. Second, the Company's March 1, 2024 Fuel Forecast True-Up Report in Docket No. E002/AA-22-179 proposed to begin returning year-end 2023 over-collected fuel costs to customers beginning April 1, 2024. Since no party objected, the Company implemented this rate change as proposed. This year-end 2023 true-up amount was later approved by the Commission's November 15, 2024 Order in Docket No. E002/AA-22-179. Finally, the Company's September 30, 2024 rate adjustment filing in Docket No. E002/AA-23-153 proposed to begin returning 2024 over-collected fuel costs to customers beginning November 1, 2024. Since no party objected, the

[4] See Part F, Attachment 5 of this Report for a compliance matrix detailing the various compliance items included in this report.
[5] See the Company's October 23, 2023 filing updating the fuel adjustment factors.

Company implemented this adjustment as proposed. We now present the final 2024 Fuel Forecast True-Up Report to present final actual data for calendar year 2024, which includes all of these adjustments impacting 2024.

B. Procedural Schedule

Under the procedural schedule detailed in Appendix A of the June 2019 Order, Comments on the true-up reports are due on April 15, Reply Comments are due on May 1, and Response Comments are due on May 15. A Commission Order is expected by August 1 to allow utilities to provide customers notice of true-up rate factors 30 days before implementation on September 1. We note that in this filing we propose to implement the true-up on April 1 to begin returning this amount to customers sooner as allowed by the June 2019 Order. Any adjustments to the true-up amount ordered by the Commission in this proceeding will be implemented on September 1 per the approved procedural schedule.

II. 2024 FORECAST VERSUS ACTUALS COMPARISON

A. Summary

The Company's 2024 actual fuel expense was $894.7 million, or $128.1 million lower than our approved forecast of $1,022.7 million. The actual average fuel cost of $33.42 per MWh was 12.3 percent lower than the authorized rate of $38.10 per MWh. Actual fuel cost collections were $1,019.4 million, only 0.3 percent lower than forecast, corresponding to Minnesota jurisdictional sales that were 0.3 percent lower than forecast. In addition, the Company implemented a mid-year adjustment in November 2024 and refunded to customers $30.5 million before the end of the year, reducing the 2024 Minnesota fuel over-collection to $94.2 million.

Table 1 below summarizes the 2024 forecast to actuals comparison.

Table 1
2024 Fuel Cost and Revenue Comparison Summary MN Jurisdiction

	Actual (000s)	Forecast (000s)	Variance (000s)	Variance (%)
Total FCA Costs	$894,690	$1,022,748	($128,058)	-12.5%
MWh Sales	26,774,079	26,842,355	(68,276)	-0.3%
FCA Cost in $/MWh	$33.42	$38.10	($4.68)	-12.3%
Fuel Collections	$1,019,438	$1,022,748	($3,310)	-0.3%
Mid-Year Adjustment Refund	($30,533)			
(Over) Under Recovery	($94,216)			
Nuclear PTC Credits	($175,612)			
Sherco 3 2011 Repl Pwr Refund	($47,957)			
Net Balance - 2023	$175			
Total (Over) Under Recovery	($317,610)			

We provide more detailed analysis of variances between the forecast and actuals for the primary components of fuel costs later in this report.

B. Management of 2024 Fuel Costs and Prudency of True-Up Proposal

For 2024, natural gas prices fell following our July 31, 2023 Reply Comments filing, and stayed lower than forecast for all of 2024, with the exception of January, leading to lower fuel costs for natural gas generation than forecast for the year. Congestion costs fell in response to low natural gas prices, along with on-going transmission system improvements, and led to lower congestion costs than forecast. Low natural gas prices contributed to lower coal generation than forecast, and lower coal costs.

Another factor that led to lower than forecast costs was a slowdown in the pace of additions of new solar projects in the community solar garden (CSG) program. The year ended with lower than forecast volumes for this high-cost program, which resulted in lower costs for customers than originally forecasted.

Although improvements have been made leading to congestion costs that were lower than forecast, and contributing to over-recovery in 2024, congestion costs remain high compared to historical periods. On-going investment in the transmission system will likely be necessary to address congestion over the longer term. Strong performance from our combined-cycle fleet led to substantial volumes of asset-based sales to MISO and greater asset-based sales revenue than forecast. However, lower than forecast revenues from financial transmission rights (FTRs) provided less of an offset to congestion costs. Asset-based sales and FTR revenues provided a meaningful offset to fuel costs and contributed to lower overall costs for customers in 2024.

As 2024 progressed and the Company began to see evidence that actual costs could be lower than forecast, we took action to provide additional relief to customers through a refund of $15 million per month beginning in November 2024.

Overall, the Company managed our diverse generation fleet throughout 2024 to the benefit of customers, and we are able to return a substantial nuclear PTC value to customers. We believe our proposal to refund $318 million through the Fuel Cost Adjustment Rider as outlined below is reasonable, and we request the Commission approve our proposal.

C. Proposed True-Up Rate Factors

We propose to refund $318 million to customers through the monthly Fuel Cost Charges, from January 2025 through March 2026. As described below, the 2025 FCA rates currently in the tariff at the time of this true-up filing include a credit for 2024 over-recovery of $15 million per month through March 2025. We propose to update the FCA rates effective April 1, 2025 such that the remainder of the $318 million is refunded to customers over the following 12 months. 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, Order Point 3[6] 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. We believe the size of the 2024 true-up due to factors we could not have predicted at the time we filed our forecast in 2023, as described above, meets the criteria for unforeseen circumstances, and the true-up amount exceeds the required threshold of plus or minus 5 percent.

Our proposal to implement a refund to customers on April 1 is submitted with 29 days' notice instead of 30 as specified in the June 2019 Order. We believe that, given the size of the refund, it is in the best interest of customers to nevertheless begin the refund on April 1. The Company will implement the refund on April 1 if no objection is received prior to that date. We understand that our true-up filing is still subject to Commission review, and we would make adjustments to the true-up rate factors if any are ordered in revised rates which would be implemented on September 1.

[6] Order Point 3 of the June 19, 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."

The proposed monthly true-up factors by customer class are shown in Part A, Attachment 3 and Part A, Attachment 4. As shown in these attachments, we implemented a mid-year rate adjustment to account for 2024 over-collected fuel costs on November 1, 2024 per our September 30, 2024 rate adjustment proposal compliance filing in this docket. This rate adjustment was calculated as a refund of $15 million per month for November 2024 through March 2025. The monthly rate adjustments related to this reduction are shown on the "2024 Mid-Year Adjustment" lines on Attachment 3 and Attachment 7. The remainder of the true-up we propose to implement in this true-up filing is shown on Attachment 3 on the "2024 True-Up Refund" lines.

The Commission's November 9, 2023 Order in this docket approved the allocation of fuel costs to Minnesota using the FERC-approved Interchange Agreement tariff which governs cost allocation between out NSP-Minnesota and NSP-Wisconsin operating companies. For the 2024 true-up, we have therefore assigned costs to the NSP-Minnesota operating company through the application of the Interchange Agreement energy allocator. We then allocated the NSP-Minnesota fuel costs to the Minnesota jurisdiction using the sales allocator. This allows customers and the Company to remain whole on prudently incurred fuel cost recovery, as Minnesota customers would pay for their allocation of the fuel costs assigned to the NSPM operating company.

To determine the proposed true-up factors by customer class, we compare the 2024 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 proposed class refund will be added to the monthly Fuel Cost Charge (FCC) for each of 12 months beginning April 1, 2025. We provide the proposed tariff sheet reflecting the proposed true-up rates as Part A, Attachment 8. Because the tariff sheet presents calendar year 2025 rates, only the April through December 2025 rates are updated in the tariff to reflect our proposed true-up factors. In our May 1, 2025 Fuel Forecast Filing to propose 2026 fuel factors, the proposed tariff sheet will include the January through March 2026 proposed true-up factors.

We propose to update the Company web site with the true-up factors by April 1, 2025. Monthly fuel rates are presented at the following link: https://www.xcelenergy.com/company/rates_and_regulations/rates/rate_riders.

D. Proposed Bill Message

In addition to updating the Company web site as noted above, the Company proposes to provide the following message to customers as a notice on their May 2025 electric bills:

> *Beginning this month the Fuel Cost Charge reflects a refund for federal production tax credits related to nuclear generation, replacement power costs related to a 2011 outage at Sherco Unit 3 as ordered by the MPUC, and an overcollection of fuel costs in 2024. This reduction will be in place for 11 months. During the next 11 months, an average residential customer will see an $81 total reduction.*

Consistent with past practice, we will work with the Department of Commerce and the Consumer Affairs Office regarding our proposed customer notices.

E. Detailed Variance Explanations

Part A, Attachment 1 of this report summarizes the year-end results by providing a comparison of forecast to actuals by fuel cost component, including the variance amount. Below we describe variances between the forecast and actuals for the primary components of fuel costs.

i. 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.

Figure 1
Hydro Forecast to Actuals

	2024 ($000)			2024 GWh			2024 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Hydro	0	0	0	877	917	(40)	$0.00	$0.00	$0.00

Company-owned hydro facilities experienced lower than normal water flows in 2024, which resulted in less hydro generation than forecast. Less hydro generation than forecast increased generation from other fuel types.

ii. 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.

Figure 2
Company-Owned Wind Forecast to Actuals

	2024 ($000)			2024 GWh			2024 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Owned Wind	0	0	0	9,648	9,269	379	$0.00	$0.00	$0.00

Actual 2024 Company-owned wind generation was greater than forecast primarily due to lower curtailment than forecast. There is no cost for wind generation in the model because it is a fuel free resource. Higher wind generation than forecast reduced generation from other fuel types and contributed to lower costs.

iii. Company-Owned Coal Generation

Coal prices are forecast based on coal purchases under contract and rail contracts in effect at the time of filing. Any coal requirements that are not under contract are forecast based on spot market prices. 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. We provide detailed outage data later in this report.

Figure 3
Company-Owned Coal Forecast to Actuals

	2024 ($000)			2024 GWh			2024 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Coal	$139,293	$174,776	($35,482)	5,513	6,497	(984)	$25.27	$26.90	($1.63)

Actual coal generation was lower than forecast due primarily to greater planned outage days in 2024 than assumed in our Reply forecast. King had additional planned outage days in June for electrical work, while Sherco 3 had additional planned outage days in the fall for steam supply work. See Part C, Attachment 4b for more information about planned outages. In addition, as shown in Chart 1 below, gas prices were low throughout the year, leading to lower LMP and less dispatch of coal generation. The reduction in coal generation is the main driver to lower than forecast costs for coal. Furthermore, realized coal and rail prices were lower than forecast leading to 6 percent lower average cost/MWh of coal generation.

iv. 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. We provide detailed outage data later in this report.

Figure 4
Company-Owned Wood/RDF Forecast to Actuals

	2024 ($000)			**2024 GWh**			**2024 $/MWh**		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Wood/ RDF	$8,731	$9,149	($417)	473	409	64	$18.46	$22.37	($3.91)

Actual 2024 Company-owned wood/RDF cost was slightly lower than forecast due to lower fuel costs.

v. Company-Owned Natural Gas Generation

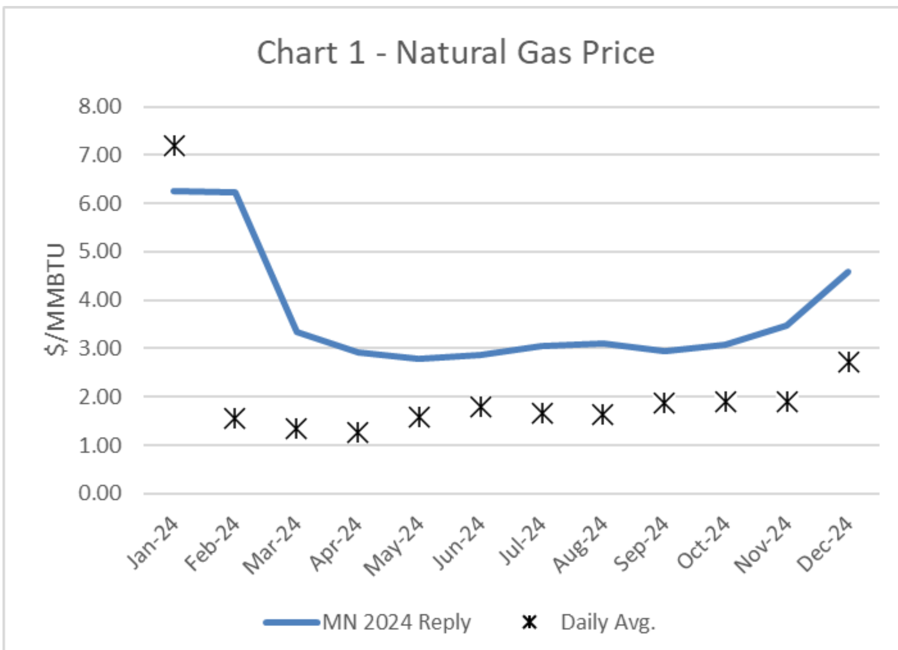
The Company-owned natural gas forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected plant conditions going forward, are 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 at the time of our July 31, 2023 Reply Comments filing. 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 we made our filing.

Figure 5
Company-Owned Natural Gas Forecast to Actuals

	2024 ($000)			2024 GWh			2024 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Owned Gas	$204,135	$225,870	($21,735)	8,821	6,550	2,271	$23.14	$34.48	($11.34)

The Company used natural gas futures prices in July 2023 for our Reply Comments filing. After January 2024, natural gas prices began to fall and remained lower than forecast for the remainder of 2024. Lower natural gas prices resulted in lower costs for natural gas generation despite greater generation than forecast. Chart 1 compares actual monthly natural gas prices to the Reply forecast.



vi. Company-Owned Nuclear Generation

The 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.

Figure 6
Company-Owned Nuclear Forecast to Actuals

	2024 ($000)			2024 GWh			2024 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Nuclear	$104,608	$113,371	($8,763)	11,956	14,249	(2,293)	$8.75	$7.96	$0.79

Actual Company-owned nuclear generation was less than forecast in 2024 primarily due to two outages at the Prairie Island Nuclear Generating Plant.

As discussed in Docket No. E002/AA-22-179, an outage that affected both Prairie Island Units 1 and 2 began in the fall of 2023 and was completed in the first quarter of 2024. Unit 1 returned to service in late January, and Unit 2 returned to service in early March. See Part C, Attachment 4b for details of the activities that occurred during those outages. See Part C, Attachment 4a for more information about additional, brief unplanned outages that occurred shortly after the units returned to service following the cable replacement project.

The second outage impacting the nuclear variance in 2024 was an extension of a planned fall refueling outage at Prairie Island Unit 1. We provide additional information about this outage as requested by Commissioner Ham at the January 23, 2025 Commission Agenda meeting. Significant planning occurs to scope activities required during a refueling outage, including equipment testing and preventative and corrective maintenance, and this work informs the forecasted outage days. In the course of the planned outage and/or during startup, unexpected issues and maintenance may be discovered that increase the planned outage time. When such issues are identified, the Company takes the necessary steps to address the issues and ensure the plant will operate safely and reliably until the next planned outage. In the case of this outage, unexpected work extended the outage beyond its planned 63 days. Planned work during the refueling outage included a reactor vessel baffle former bolt and clevis bolt replacement project. Difficulties with bolt removal and insertion resulted in this work taking longer than originally expected. Then, during startup, both reactor coolant pumps indicated high vibrations and one pump indicated seal leakage. Therefore, per plant procedure, both pumps needed to be shut down. The plant was cooled down and depressurized, and both reactor coolant pumps were uncoupled for maintenance which included seal replacement on one pump. After completing maintenance and re-coupling the pumps, plant startup activities recommenced. Pump vibrations had been eliminated, but indications of leakage remained on the seal that had been replaced. The plant was cooled and depressurized and the seal was replaced with a new seal. Following restart of the pump, no further leakage was identified. The unit ultimately returned to service on January 17, 2025. Planned and discovered activities that occurred during the refueling outage are noted in Part C, Attachment 4b.

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

Figure 7
Purchased Natural Gas Forecast to Actuals

	2024 ($000)			2024 GWh			2024 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Gas PPAs	$118,274	$142,457	($24,183)	4,779	4,390	389	$24.75	$32.45	($7.70)

As discussed above, the Company used natural gas futures prices in July 2023 for our Reply Comments filing. After January 2024, natural gas prices began to fall and remained lower than forecast for the remainder of 2024. Lower natural gas prices resulted in lower costs for natural gas generation despite greater generation than forecast. Chart 1, above, compares actual monthly natural gas prices to the Reply forecast.

viii. 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.

Figure 8
Solar PPAs Forecast to Actuals

	2024 ($000)			2024 GWh			2024 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Solar PPAs	$55,139	$57,382	($2,243)	848	868	(20)	65.02	66.11	(1.09)

Actual 2024 PPA solar costs were slightly lower than forecast.

ix. Purchased Solar Generation (Community Solar Gardens)

The CSG program forecast includes expectations of future growth based on current applications for gardens seeking to participate in the program. We identified current projects to anticipate in-service dates and estimate project completion (in capacity) by month and year. We also forecast additional applications based on a three-year historical average (removing outliers) to help account for our 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 2024.

The market cost of energy from the solar gardens generation is determined based on the assumed 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.

Figure 9
Community Solar Gardens Forecast to Actuals

	2024 ($000)			2024 GWh			2024 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
CSG Market	$42,601	$79,885	($37,284)						
CSG Above Market	$180,036	$249,377	($69,341)						
Total CSG	$222,637	$329,262	($106,625)	1,586	2,312	(726)	$140.38	$142.41	($2.04)

Costs for CSGs were lower than forecast due to lower generation from CSGs than assumed in our 2024 Reply Comments as the installation of new CSGs was lower than assumed in the Reply forecast.

See Part C, Attachments 8-10 for more details about actual CSG above-market costs and total number of gardens and subscriptions.

x. 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.

Figure 10
Wind PPAs Forecast to Actuals

	2024 ($000)			2024 GWh			2024 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Wind PPAs	$224,133	$216,107	$8,026	5,772	6,048	(276)	$38.83	$35.73	$3.10

Actual purchased wind generation $/MWh was higher than forecast because PPA wind generation was lower than forecast due to greater curtailment for wind PPAs overall. See Part C, Attachments 1, 2, and 7 for more details regarding wind curtailment and its relation to PPA pricing.

xi. Purchased Generation – Other

PPAs that do not fit within one of the prior three categories (primarily small hydro PPAs, the remaining biomass PPA, and the PPA with Manitoba Hydro) are modeled based on historical generation (for the small hydro PPAs) or according to their contract terms (for the biomass and Manitoba Hydro PPAs). Price is determined based on contract terms or based on historical prices with assumed escalation.

Figure 11
Other PPAs Forecast to Actuals

	2024 ($000)			2024 GWh			2024 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Other PPAs	$191,029	$195,042	($4,013)	2,288	2,399	(111)	$83.49	$81.30	$2.19

Actual 2024 costs for other purchased generation were lower than forecast due to lower generation volumes from this mix of other PPA contracts.

xii. 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. In addition, 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 represent the equivalent MISO Day 2 and Day 3 costs for the Forecast.

Figure 12
2024 Net MISO Costs and Revenues

	($000)			GWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Net MISO	($67,368)	($93,031)	$25,663	(12,235)	(10,477)	(1,758)

Net MISO revenue was lower than forecast due to greater volume of purchases from the MISO market and lower than forecast revenues from FTRs. Lower than forecast LMP led to greater purchases from MISO. In addition, congestion costs were lower than forecast as shown in Table 2. Congestion decreased as a result of on-going improvements to the transmission system in addition to lower natural gas prices.

Table 2 below compares the 2024 forecast to actuals by primary MISO charge type.

Table 2
2024 MISO Charge Type Forecast to Actuals ($000s)

Category	Actual	Forecast	Variance
Congestion	$173,958	$259,444	($85,486)
FTR	($45,210)	($91,918)	$46,708
Incremental Transmission losses	$36,137	$14,836	$21,301
RSG/RNU	$7,669	$9,570	($1,901)
ASM	($3,237)	($3,394)	$157
MISO Charges TOTAL	**$169,317**	**$188,538**	**($19,221)**

We provide additional MISO charge details in Part B, Attachments 1-14. In addition, we discuss system congestion in Part B, Attachment 1 and within our wind curtailment report provided as Part C, Attachment 1.

Table 3 compares the forecast to actual Asset-Based Margins.

Table 3
Actual 2024 Asset-Based Margins ($ millions)

	Revenue	Cost	Margin
Forecast	292.0	202.8	89.2
Actuals	309.9	223.1	86.8
Variance	17.9	20.3	-2.4

Asset-based margins were within 2.6 percent of forecast as the Company's low cost combined-cycle portfolio was heavily relied on by MISO throughout the year.

xiii. Retail Sales

The Minnesota sales forecast used in the 2024 Fuel Forecast was developed in March 2023. Actual Minnesota retail sales in 2024 were 27,722,191 MWh, compared with the 2024 sales forecast of 28,147,613 MWh, resulting in a sales-to-forecast variance of -425,422 MWh (1.5 percent).[7] As summarized in Table 4 below, contributing factors to the forecast variance include: higher than expected savings from demand side management (DSM) programs, lower than anticipated load additions from commercial and industrial customers (C&I), decreased sales due to mild weather, lower than forecast Combined Heat and Power (CHP) and Large C&I solar generation, greater than anticipated distributed solar generation, and other non-specified factors. In summary, weather impacts was the largest contributor to the forecast variance.

Table 4
Sales-to-Forecast Variance in 2024 (MWh)

	2024 Minnesota Juris.
Spring 2023 Forecast of 2024 Sales	28,147,613
Actual 2024 Cal Mth Sales	27,722,191
Actual Sales Variance from Forecast	-425,422
Contribution to Forecast Variance:	
DSM Forecast Variance	-60,514
	[PROTECTED DATA BEGINS
C&I Load additions/reductions	
	PROTECTED DATA ENDS]
2024 Weather Impact	-340,754
	[PROTECTED DATA BEGINS
CHP & Large Solar Forecast Variance	
	PROTECTED DATA ENDS]
Solar Forecast Variance	-4,024
Other Factors	36,668
Total	-425,422

[7] Sales for Renewable*Connect and Windsource programs are excluded from these figures in the fuel clause mechanism.

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

i. Costs Excluded from Fuel Costs

Part A, Attachment 2 provides monthly details of the direct assigned Windsource and Renewable*Connect amounts for 2024, which are excluded from total fuel costs. We note that all Windsource customers have now been transitioned to the new Renewable*Connect programs and have ceased being billed under the Windsource rate, effective April 1, 2024.[8]

ii. Solar Energy Standard Exclusion

The Commission's January 16, 2018 Order in Docket No. E002/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.[9] The 2024 annual FCA recovery is shown in Part A, Attachment 2, line 48, the month the excluded customers were issued their bill credit.[10] The amount is also included in the "Other Adjustments" line on Part A, Attachment 1. This charge was not included in the original forecast given the small amount and in order to include only the exact amount after it is known.

iii. Saver's Switch Discount Recovery

Effective January 1, 2024 with the implementation of final rates in the Company's last electric rate case in Docket No. E002/GR-21-630, there is no longer a Fuel Clause component of the Saver's Switch discount.[11] Therefore, Part A, Attachment 1 shows the Saver's Switch discount amount is $0 in 2024.

iv. Nuclear Production Tax Credits

In August 2022, President Biden signed into law the Inflation Reduction Act of 2022 (IRA). Among other things, the IRA extended and expanded PTC and investment tax credit (ITC) benefits for clean energy resources, along with creating a new PTC for existing nuclear resources. Under the IRA, beginning in 2024, nuclear facilities are

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[8] See the Company's May 1, 2024 final Windsource compliance report in Docket No. E002/M-01-1479.
[9] The Fuel Clause Adjustment (FCA) and Renewable Development Fund (RDF) Riders.
[10] The Company provided this amount in the June 1, 2024 SES Exclusion Annual Report filed in Docket No. E002/M-17-425.
[11] See the Commission's July 17, 2023 Order in Docket No. E002/GR-21-630. Order Point No. 84.

eligible for base credits of 0.3 cents/kWh generated by existing facilities. This base credit is eligible to increase by a factor of five, to 1.5 cents/kWh, provided certain prevailing wage requirements are met. The value of the credits will be 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 the Company's last rate case in Docket No. E002/GR-21-630 approved the Company's proposal to include a nuclear PTC tracker and refund in the Fuel Clause.[12]

Nuclear PTCs and the applicable prevailing wage requirements are new in 2024, and as such, we are still working through the review and documentation process to ensure compliance with these requirements. While the Company has calculated a value for 2024 nuclear PTCs, for instance, we believe there may be additional costs incurred to ensure compliance with the prevailing wage requirements. In the interest of returning the credits to customers as soon as possible, however, we have included the current 2024 calculation of the credits in this true-up filing. Any final adjustments to the 2024 nuclear PTC value will be addressed in our Fuel Forecast True-Up Report for 2025 due by March 1, 2026, in Docket No. E002/AA-24-63.

In addition, the Company is still working to execute the sale of the 2024 nuclear PTCs. We expect to execute the transactions by May 2025. To account for this delay, Part A, Attachment 4 reflects the inclusion of the nuclear PTC credits beginning in May 2025 instead April when we propose to implement the overall rate reduction. The nuclear PTC credits therefore impact fuel rates for only 11 months instead of the full 12 months. If the timing of executing the transactions changes the final value, we would reflect any changes in our March 1, 2026 True-Up Report, as noted above.

The estimated Minnesota allocated value of the nuclear PTCs for 2024 is $175.8 million, inclusive of transaction costs. See Attachment 10 for the nuclear PTC tracker detailing the derivation of this amount.

v. Sherco 3 Replacement Power Costs Refund

In its January 23, 2025 Compliance filing in Docket Nos. E999/AA-18-373, E999/AA-17-492, E999/AA-16-523, E999/AA-14-579, E002/GR-13-868, E999/AA-13-599, and E002/GR-12-961, the Company proposed providing full refund details for Sherco 3 replacement power costs in our 2024 Fuel Forecast True-Up Report.

[12] See Order Point No. 113.

Calculated as ordered by the Commission in its December 24, 2024 Order in the above-referenced dockets, the total refund related to the Sherco 3 outage is approximately $48 million. See Part A, Attachment 9 showing the derivation of the Sherco 3 refund amount including interest at the Prime Rate until the refund is proposed to begin on April 1 and recognition of the timing of the GE litigation settlement. We note that since filing our January 23 refund plan compliance, we have updated the calculation to include the applicable interest rate for the first three months of 2025 prior to the April 1 implementation of the refund. Part A, Attachment 4 page 3 through page 5 show that the refund is applied consistent with how we have previously included refunds through the FCA and consistent with FCA class allocation.

vi. St. Paul Cogeneration PPA Adjustment

As discussed in our October 2, 2024 compliance filing in Docket No. E002/M-21-590, we neglected to make an update to our fuel clause calculations for the 2023 capacity impact of the PPA between the Company and St. Paul Cogeneration, LLC, resulting in $102,613 that remained to be credited to Minnesota customers. As proposed in that filing, we have included this adjustment in this True-Up Report. See Part A, Attachment 2. Adjustments for the 2024 capacity impact have been included in the monthly over/under calculations.

vii. Black Dog and High Bridge Gas Adjustment

In reviewing our lost and unaccounted for gas level for the Company's 2024 Automatic Adjustment of Charges Report – Gas (AAA) filed on September 3, 2024 in Docket No. G999/AA-24-138, the Company discovered an allocation issue between gas used in two of our electric generation plants and gas used by our Local Distribution Company (LDC) customers. Black Dog and High Bridge are two of Xcel Energy's natural gas-powered electric generating plants, and they take natural gas transportation service from our LDC. Each plant has an end-user allocation agreement with the LDC, in which the LDC communicates to Northern Natural Gas (NNG) the volumes used by the plants. NNG allocates Xcel Energy's purchase gas costs between the LDC and the electric utility using these volumes. The Company found that the billing meters at these two plants were under-reporting gas usage. Therefore, the usage reported to NNG was under-reported, and NNG allocated a smaller portion of gas costs to the electric utility than was appropriate. The Company determined that approximately $12.4 million in gas expense was misallocated to the LDC during the 2023-2024 gas year, and in our 2024 AAA Report we adjusted the LDC purchase gas commodity expense to remove these dollars.

In this filing, we have included approximately $14 million in electric fuel costs that were re-allocated from the LDC to the electric utility fuel expense in 2024. This adjustment includes additional months beyond the gas reporting year. We have identified this as an "Unusual Item" in Attachment, Part F, Attachment 3 of this Fuel Forecast True-Up Report.

IV. REPORTING IN COMPLIANCE WITH MINNESOTA RULES

This filing contains information provided in response to the annual reporting requirements specified in the following rule sections:

7825.2800 Policies and Actions
7825.2810 Annual Report of Automatic Adjustment Charges
7825.2820 Annual Auditor's Report
7825.2830 Annual Five-Year Projection
7825.2840 Annual Notice of Reports Availability

A. 7825.2800 Annual Reports: Policies and Actions

Part D, Attachments 1-10 include information and supporting data in compliance with the following topics listed in Minn. Rule 7825.2800:

- Procurement Policies
- Dispatching Policies and Procedures
- Fuel Supply
- Conservation Policy
- Other Actions

The Commission's June 2019 Order approved a rule variance requiring this information to be submitted by March 1 each year with the Annual True-Up filing.

B. 7825.2810 Annual Report: Automatic Adjustment of Charges

Minn. Rule 7825.2810 requires the following information:

- Base Cost of Fuel
- Billing Adjustment Amounts Charged Customers for Each Month
- Total Cost of Fuel Delivered to Customers
- Revenue Collected from Customers for Energy Delivered
- Monthly Fuel Cost Charge

The Commission's June 2019 Order approved a rule variance requiring this information to be submitted by March 1 each year with the Annual True-Up filing.

1. Base Cost of Fuel

The Commission's November 5, 2019 Order in Docket No. E999/CI-03-802 approved the Company's proposed changes to the base cost of energy. The Company will no longer recover energy-related costs via a base costs of energy. For electric rate case filings, a representative level of test year fuel expense and revenues will be set using the most recent fuel expense forecast filed in the Annual Fuel Forecast docket. Our tariff sheets have been updated to reflect these changes.

As required by the Order, the Company included in our 2022 test year rate case application (including plan years 2023 and 2024) a demonstration that the proposed base rates exclude Fuel Clause-Adjustment-related costs.[13]

2. Monthly Fuel Cost Charges

See Part A, Attachment 7 for the monthly fuel cost charges implemented in 2024.

C. 7825.2820 Annual Auditor's Report

The Annual Auditor's Report is provided as Part E, Attachment 2.

The Commission's March 20, 2002 Order in Docket Nos. E002/M-01-1953 and E,G999/AA-02-950 approved the Company's proposed method to separate, for accounting purposes, the costs and effects of financial instruments purchased to meet the needs of retail electric or natural gas ratepayers from the financial instruments purchased to mitigate price risk in the Company's non-jurisdictional wholesale electric sales activity. The Commission's Order also required the Company to submit a written request that its external auditors specifically examine these transactions in preparation of the auditor's report, to be submitted with the Company's 2001-2002 electric and

[13] Docket No. E002/GR-21-630

natural gas AAA reports submitted September 1, 2002. The Company continues to annually provide such a written request to its external auditors. Part E, Attachment 1 is a copy of the letter that was sent to facilitate the independent audit by Deloitte & Touche LLP.

Additional audit reporting requirements included in the Commission's July 21, 2017 Order in the 2015 AAA Report proceeding (Docket No. E999/AA-15-611) are discussed in the letter outlining audit requirements that was sent to the auditor.

D. 7825.2830 Annual Five-Year Projection

The monthly five-year projection of fuel cost by energy source for the period of 2025-2029 was provided as part of the Company's May 1, 2024 fuel forecast for calendar year 2025 filed in Docket No. E002/AA-24-63. The monthly five-year projection of fuel cost by energy source for the period of 2026-2030 will be provided as part of the Company's May 1, 2025 fuel forecast for calendar year 2026.

E. 7825.2840 Annual Notice of Reports Availability

Minn. Rule 7825.2840 requires utilities to provide notice of the availability of the reports defined in parts 7825.2800 to 7825.2830 to all intervenors in the utility's two previous general rate cases. In compliance with this rule, the Company is providing notice to all intervenors in our 2021 and 2024 electric rate cases who have requested to remain on the docket service lists.

V. OTHER COMPLIANCE ITEMS

Please see the Table of Contents for a complete list of attachments provided in compliance with a variety of Commission Orders in various dockets.

CONCLUSION

Xcel Energy respectfully requests the Commission approve our 2024 Annual Fuel Forecast True-Up Report, our proposal to return $318 million to customers over 12 months for the 2024 reporting year, and the Electric AAA reporting requirements included in this report.

Dated: March 3, 2025

Northern States Power Company

TABLE OF CONTENTS

Northern States Power Company
Electric Utility - State of Minnesota
Comparison of Actual Fuel and Purchased Power Costs to Filed Forecast

	2024 ($'000)	
MN Jurisdiction Fuel Collections	$1,019,438	
MN Jurisdiction Fuel Costs	$671,120	
(Over)/Under Recovery (Deferred to Balance Sheet)	**($348,318)**	**Liability**
Refunds via Mid-Year Rate Adjustment	($30,533)	
Net (Over)/Under Recovery	**($317,785)**	**Net Liability**

	2024 ($'000)				2024 GWh			2024 $/MWh		
	Actual	Forecast (1)	Variance	% Variance	Actual	Forecast (1)	Variance	Actual	Forecast (1)	Variance
Coal	$139,293	174,776	($35,482)		5,513	6,497	(984)	$25.27	$26.90	-$1.63
Wood/RDF	8,731	9,149	(417)		473	409	64	$18.46	$22.37	-$3.91
Natural Gas & Oil	204,135	225,870	(21,734)		8,821	6,550	2,270	$23.14	$34.48	-$11.34
Wind, Solar, Hydro		0	0		10,598	10,237	361	$0.00	$0.00	$0.00
Nuclear Fuel	104,608	113,371	(8,763)		11,956	14,249	(2,293)	$8.75	$7.96	$0.79
Total Fuel	$456,768	$523,165	($66,397)	-12.7%	37,361	37,942	(581)	$12.23	$13.79	-$1.56
Purchased Energy	382,529	347,919	34,610		9,704	7,033	2,671	$39.42	$49.47	-$10.05
Purchased Energy (Solar)	55,139	57,382	(2,243)		848	868	(20)	$65.04	$66.14	-$1.10
Community Solar*Gardens	222,637	329,263	(106,625)		1,586	2,312	(726)	$140.34	$142.42	-$2.08
Purchased Energy (Wind)	224,133	216,107	8,026		5,772	6,048	(276)	$38.83	$35.73	$3.10
MISO Market Charges	169,317	188,538	(19,221)							
Total Purchased Power	$1,053,756	$1,139,209	($85,453)	-7.5%	17,910	16,261	1,650	$58.84	$70.06	-$11.22
Less Sales Revenue	($309,911)	(291,989)	($17,922)		(14,872)	(10,721)	(4,151)	**$20.84**	**$27.23**	**-$6.40**
Less Costs Direct Assigned (2)	(213,930)	(291,710)	77,780							
Net System Costs	**$986,682**	**$1,078,675**	**($91,992)**	**-8.5%**	40,399	43,482	**(3,082)**	**$24.42**	**$24.81**	**-$0.38**
NSPM I/A Energy Allocator	**82.79%**	**82.35%**								
NSPM Fuel Costs	**$816,847**	**888,327**								
Calculator Month Mwh Sales (3)	**31,121,287**	**31,199,824**								
System Cost in $/Mwh	**$26.25**	**$28.47**	**($2.22)**	**-7.8%**						
MN Jurisdictional Fuel Cost	***$702,990***	***764,429***	***($61,439)***							
Direct Assigned Costs:										
Solar Gardens - Above Market Cost	180,010	249,377	(69,367)							
Biomass Termination Costs	8,938	8,942	(4)							
St. Paul Cogeneration	1,191	0	1,191							
Net Direct Assigned Costs	**$190,139**	**$258,319**	**($68,180)**	**-26.4%**						
MN Direct Assigned	***$190,139.18***	***$258,319***	***($68,180)***							
SES Exemption	***1,663***		***1,663***							
Saver Switch	***0***		***0***							
St. Paul Cogeneration (2023 Capacity)	***(103)***		***(103)***							
Sherco 3 Outage Replacement Energy Cos	***(47,957)***		***(47,957)***							
Nuclear PTCs	***(175,612)***		***(175,612)***							
Total MN Jurisdiction FCA Costs	**$671,120**	**$1,022,748**	**($351,628)**	**-34.4%**						
MN Jursdiction Mwh Sales	**26,774,079**	**26,842,355**	**(68,276)**	**-0.3%**						
MN Jurisdiction FCA Cost in $/MWh	**$25.07**	**$38.10**	**($13.03)**	**-34.2%**						

(1) As filed with the MPUC in July 2023
(2) Community Solar Garden, Windsource, Renewable Connect
(3) For actual month, sales allocator is NSPM Calendar Month Sales. For forecast month, sales allocator is System Calendar Month Sales.

Northern States Power Company
Electric Utility - State of Minnesota
2024 Fuel, Purchased Power and Other Costs

	($000)	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	2024 Total
	Own Generation													
	Fossil Fuel													
1	Coal	$23,223	$9,345	$4,983	$6,136	$6,709	$14,388	$21,960	$16,864	$12,490	$5,343	$5,840	$12,012	$139,293
2	Wood/RDF	$147	$654	$733	$1,014	$691	$585	$670	$873	$397	$768	$812	$1,387	$8,731
3	Natural Gas CC	$20,689	$11,942	$13,812	$7,133	$10,438	$9,002	$16,644	$13,964	$22,680	$9,926	$13,033	$19,900	$169,165
4	Natural Gas & Oil CT	$1,947	$1,024	$987	$1,957	$1,800	$1,671	$5,378	$5,964	$5,420	$1,993	$2,952	$3,878	$34,970
5	Total Fossil Fuel 1+2+3+4	$46,006	$22,964	$20,515	$16,240	$19,638	$25,646	$44,652	$37,666	$40,987	$18,031	$22,638	$37,177	$352,160
6	Hydro	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Wind	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Nuclear Fuel	$4,029	$6,196	$9,339	$11,236	$11,236	$10,431	$11,168	$11,175	$9,700	$6,999	$5,927	$7,172	$104,608
9	Total Fuel 5+6+7+8	$50,035	$29,161	$29,854	$27,476	$30,874	$36,077	$55,820	$48,840	$50,687	$25,030	$28,565	$44,349	$456,768
	Purchased Energy													
10	LT Purchased Energy (Gas)	$9,801	$8,756	$6,798	$4,536	$4,795	$8,596	$15,535	$12,629	$11,778	$8,159	$12,934	$13,957	$118,274
11	LT Purchased Energy (Solar)	$1,575	$3,244	$5,023	$4,954	$6,763	$6,407	$7,034	$6,071	$5,942	$4,707	$2,344	$1,074	$55,139
12	Community Solar*Gardens	$7,011	$15,162	$21,391	$19,506	$25,847	$23,303	$24,310	$26,326	$24,958	$19,046	$9,152	$6,625	$222,637
13	LT Purchased Energy (Wind)	$18,001	$20,630	$25,032	$23,703	$19,573	$14,316	$10,693	$12,043	$19,632	$22,047	$20,350	$18,113	$224,133
14	LT Purchased Energy (Other)	$14,092	$12,729	$12,367	$11,588	$20,003	$21,063	$15,066	$19,411	$18,618	$23,505	$13,041	$9,546	$191,029
15	Total Purchased Energy 10+11+12+13+14	$50,480	$60,520	$70,611	$64,288	$76,981	$73,686	$72,639	$76,481	$80,929	$77,465	$57,820	$49,315	$811,213
16	ST Market Purchase	$18,186	$1,848	($4,500)	$1,765	$5,027	$5,512	$11,902	$10,570	$1,455	$8,532	$2,863	$10,067	$73,226
17	Asset Based Sales Revenues (Market Sales)	($43,157)	($13,598)	($15,605)	($7,109)	($21,136)	($25,426)	($48,212)	($39,245)	($25,691)	($15,063)	($20,599)	($35,070)	($309,911)
18	Net Market Cost 16+17	($24,971)	($11,751)	($20,104)	($5,344)	($16,109)	($19,914)	($36,311)	($28,674)	($24,236)	($6,531)	($17,736)	($25,003)	($236,685)
19	MISO Cost	$14,798	$6,928	$15,540	$15,575	$7,655	$4,789	$9,387	$8,595	$33,361	$19,752	$17,606	$15,331	$169,317
20	Net MISO D2 and ASM Cost 18+19	($10,174)	($4,823)	($4,564)	$10,230	($8,454)	($15,125)	($26,924)	($20,079)	$9,125	$13,222	($131)	($9,672)	($67,369)
21	**Total System Cost 9+15+20**	$90,342	$84,858	$95,900	$101,994	$99,401	$94,638	$101,535	$105,242	$140,741	$115,716	$86,254	$83,992	$1,200,613
22	Less Solar Gardens - Above Market Cost	($5,485)	($12,368)	($17,026)	($16,369)	($21,361)	($17,012)	($18,534)	($19,440)	($19,422)	($15,119)	($6,997)	($11,004)	($180,137)
23	Less WindSource	($1,687)	($2,066)	($3,037)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6,791)
24	Less Renewable Connect	($566)	($724)	($918)	($166)	($2,085)	($3,671)	($2,891)	($3,262)	($3,877)	($3,732)	($2,241)	($2,871)	($27,003)
25	Total Costs Direct Assigned 22+23+24	($7,738)	($15,158)	($20,981)	($16,534)	($23,445)	($20,683)	($21,425)	($22,702)	($23,299)	($18,851)	($9,238)	($13,875)	($213,930)
26	**Net System Costs 21+25**	$82,604	$69,699	$74,919	$85,459	$75,955	$73,955	$80,110	$82,540	$117,442	$96,866	$77,015	$70,117	$986,682
27	Interchange Allocator	82.25%	82.37%	82.34%	82.34%	83.30%	83.29%	83.68%	83.44%	83.35%	82.56%	82.17%	82.05%	
28	NSPM System Costs 26*27	$67,939	$57,414	$61,688	$70,365	$63,267	$61,594	$67,038	$68,869	$97,891	$79,968	$63,286	$57,529	$816,847
	Calendar Month MWh Sales													
29	Total NSPM Retail Sales	2,761,990	2,446,157	2,532,802	2,301,195	2,475,024	2,712,590	3,159,984	3,039,734	2,779,609	2,580,500	2,489,623	2,790,192	32,069,400
30	Less Minnesota WindSource	(44,260)	(41,189)	(39,962)	0	0	0	0	0	0	0	0	0	(125,411)
31	Less Minnesota Renewable*Connect	(20,355)	(17,575)	(20,444)	(67,158)	(53,472)	(67,090)	(92,046)	(105,518)	(120,373)	(90,212)	(66,145)	(102,314)	(822,702)
32	**Net NSPM MWh Sales 29+30+31**	2,697,375	2,387,393	2,472,396	2,234,037	2,421,552	2,645,500	3,067,938	2,934,216	2,659,236	2,490,288	2,423,478	2,687,878	31,121,287
33	Minnesota Jurisdictional Retail Sales	2,367,264	2,109,702	2,175,838	1,985,736	2,155,336	2,357,064	2,736,363	2,630,174	2,422,765	2,242,162	2,143,624	2,396,164	27,722,192
34	Less Minnesota WindSource	(44,260)	(41,189)	(39,962)	0	0	0	0	0	0	0	0	0	(125,411)
35	Less Minnesota Renewable*Connect	(20,355)	(17,575)	(20,444)	(67,158)	(53,472)	(67,090)	(92,046)	(105,518)	(120,373)	(90,212)	(66,145)	(102,314)	(822,702)
36	**Total Minnesota Retail Sales 33+34+35**	2,302,649	2,050,938	2,115,432	1,918,578	2,101,864	2,289,974	2,644,317	2,524,656	2,302,392	2,151,950	2,077,479	2,293,850	26,774,079
37	**NSPM Fuel Costs in cents/kWh 28/32x100**	2.519¢	2.405¢	2.495¢	3.150¢	2.613¢	2.328¢	2.185¢	2.347¢	3.681¢	3.211¢	2.611¢	2.140¢	2.625¢
	Minnesota Jurisdictional Energy Costs													
38	NSPM Fuel Costs in cents/kWh 37	2.519¢	2.405¢	2.495¢	3.150¢	2.613¢	2.328¢	2.185¢	2.347¢	3.681¢	3.211¢	2.611¢	2.140¢	
39	Total Minnesota Retail Sales Subject to FCA 36	2,302,649	2,050,938	2,115,432	1,918,578	2,101,864	2,289,974	2,644,317	2,524,656	2,302,392	2,151,950	2,077,479	2,293,850	26,774,079
40	Minnesota Costs Subject to FCA 38x39/100	$58,004	$49,325	$52,780	$60,435	$54,922	$53,311	$57,778	$59,254	$84,751	$69,099.115	$54,243	$49,088	$702,990
	MN Direct Assigned Cost (Solar Gardens & Biomass PPA Buyout)													
41	Solar Garden Above Market Direct Recovery	$5,484	$12,356	$17,010	$16,354	$21,343	$16,999	$18,516	$19,438	$19,409	$15,107	$6,992	$11,002	$180,010
42	St. Paul Cogen	$106	$131	$119	$0	$124	$76	$48	$147	$134	$77	$133	$98	$1,191
43	Benson and Laurentian Buyout costs	$762	$759	$756	$753	$749	$746	$743	$740	$737	$733.849	$731	$728	$8,938
44	MN Direct Assigned Total 41+42+43	$6,352	$13,246	$17,885	$17,106	$22,216	$17,821	$19,307	$20,325	$20,279	$15,917.728	$7,857	$11,828	$190,139
45	Minnesota Direct Assigned Cost in cents/kWh 44/36*100	0.276¢	0.646¢	0.845¢	0.892¢	1.057¢	0.778¢	0.730¢	0.805¢	0.881¢	0.740¢	0.378¢	0.516¢	0.710¢
46	Minnesota Fuel Costs in cents/kWh 37+45	2.795¢	3.051¢	3.340¢	4.042¢	3.670¢	3.106¢	2.915¢	3.152¢	4.562¢	3.951¢	2.989¢	2.656¢	3.335¢
47	**Minnesota Fuel Costs Subtotal 46*36/100**	$64,356	$62,571	$70,665	$77,542	$77,138	$71,132	$77,085	$79,578	$105,031	$85,017	$62,099	$60,916	$893,129
	Other Adjustments													
48	SES Exemption	$0	$0	$1,663	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,663
49	St. Paul Cogeneration (2023 Capacity)	$0	$0	$0	$0	$0	$0	($103)	$0	$0	$0	$0	$0	($103)
50	Other Adjustments Total 48+49	$0	$0	$1,663	$0	$0	$0	($103)	$0	$0	$0	$0	$0	$1,561
51	**Minnesota Fuel Costs 47+50**	$64,356	$62,571	$72,328	$77,542	$77,138	$71,132	$76,983	$79,578	$105,031	$85,017	$62,099	$60,916	$894,690
52	**Minnesota Fuel Costs in cents/kWh 51/36x100**	2.795¢	3.051¢	3.419¢	4.042¢	3.670¢	3.106¢	2.911¢	3.152¢	4.562¢	3.951¢	2.989¢	2.656¢	3.342¢
53	Sherco 3 Outage Replacement Energy Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($47,957)	($47,957)
54	Nuclear PTCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($175,612)	($175,612)
55	**Sherco and NPTC refund $ 53+54**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($223,569)	($223,569)
56	**Sherco and NPTC refund rate (cents) 55/36x10**	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	-9.746¢	-0.835¢
57	**Minnesota Fuel Costs with Refunds in cents/kWh 52+56**	2.795¢	3.051¢	3.419¢	4.042¢	3.670¢	3.106¢	2.911¢	3.152¢	4.562¢	3.951¢	2.989¢	-7.091¢	2.507¢
58	**Minnesota Fuel Costs with Refunds in $/MWh 57x10**	$27.95	$30.51	$34.19	$40.42	$36.70	$31.06	$29.11	$31.52	$45.62	$39.51	$29.89	($70.91)	$25.07
	$/KWh	$0.02795	$0.03051	$0.03419	$0.04042	$0.03670	$0.03106	$0.02911	$0.03152	$0.04562	$0.03951	$0.02989	($0.07091)	$0.02507

2025 Monthly Fuel Clause Charges with 2024 Mid-Year Adj., 2024 True-Up and Other Refunds ($/KWh)

	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
January						
Forecast	$0.03269	$0.03267	$0.03218	$0.04087	$0.02568	$0.02459
2024 Mid-Year Adjustment.	($0.00652)	($0.00652)	($0.00642)	($0.00815)	($0.00512)	($0.00491)
Total	$0.02617	$0.02615	$0.02576	$0.03272	$0.02056	$0.01968
February						
Forecast	$0.03573	$0.03570	$0.03517	$0.04468	$0.02806	$0.02686
2024 Mid-Year Adjustment.	($0.00754)	($0.00753)	($0.00743)	($0.00943)	($0.00593)	($0.00567)
Total	$0.02819	$0.02817	$0.02774	$0.03525	$0.02213	$0.02119
March						
Forecast	$0.03611	$0.03608	$0.03554	$0.04516	$0.02835	$0.02713
2024 Mid-Year Adjustment.	($0.00692)	($0.00692)	($0.00681)	($0.00865)	($0.00544)	($0.00520)
Total	$0.02919	$0.02916	$0.02873	$0.03651	$0.02291	$0.02193
April						
Forecast	$0.03871	$0.03867	$0.03809	$0.04841	$0.03039	$0.02909
2024 True-Up Refund	($0.00227)	($0.00227)	($0.00224)	($0.00284)	($0.00178)	($0.00171)
Sherco 3 Refund	($0.00222)	($0.00222)	($0.00219)	($0.00278)	($0.00174)	($0.00167)
Total	$0.03422	$0.03418	$0.03366	$0.04279	$0.02687	$0.02571
May						
Forecast	$0.03614	$0.03611	$0.03557	$0.04519	$0.02838	$0.02717
2024 True-Up Refund	($0.00203)	($0.00203)	($0.00200)	($0.00254)	($0.00159)	($0.00152)
Sherco 3 Refund	($0.00199)	($0.00199)	($0.00196)	($0.00249)	($0.00156)	($0.00149)
NPTC Refund	($0.00793)	($0.00792)	($0.00780)	($0.00992)	($0.00622)	($0.00596)
Total	$0.02419	$0.02417	$0.02381	$0.03024	$0.01901	$0.01820
June						
Forecast	$0.03707	$0.03704	$0.03648	$0.04637	$0.02909	$0.02785
2024 True-Up Refund	($0.00177)	($0.00177)	($0.00175)	($0.00222)	($0.00139)	($0.00133)
Sherco 3 Refund	($0.00173)	($0.00173)	($0.00171)	($0.00217)	($0.00136)	($0.00130)
NPTC Refund	($0.00691)	($0.00690)	($0.00680)	($0.00864)	($0.00542)	($0.00519)
Total	$0.02666	$0.02664	$0.02622	$0.03334	$0.02092	$0.02003
July						
Forecast	$0.03524	$0.03520	$0.03467	$0.04408	$0.02764	$0.02646
2024 True-Up Refund	($0.00150)	($0.00150)	($0.00147)	($0.00187)	($0.00118)	($0.00113)
Sherco 3 Refund	($0.00147)	($0.00147)	($0.00144)	($0.00184)	($0.00115)	($0.00110)
NPTC Refund	($0.00587)	($0.00587)	($0.00578)	($0.00734)	($0.00461)	($0.00441)
Total	$0.02640	$0.02636	$0.02598	$0.03303	$0.02070	$0.01982
August						
Forecast	$0.03393	$0.03390	$0.03339	$0.04245	$0.02662	$0.02548
2024 True-Up Refund	($0.00158)	($0.00158)	($0.00155)	($0.00198)	($0.00124)	($0.00119)
Sherco 3 Refund	($0.00155)	($0.00155)	($0.00152)	($0.00194)	($0.00122)	($0.00116)
NPTC Refund	($0.00618)	($0.00617)	($0.00608)	($0.00772)	($0.00485)	($0.00464)
Total	$0.02462	$0.02460	$0.02424	$0.03081	$0.01931	$0.01849
September						
Forecast	$0.03244	$0.03241	$0.03193	$0.04058	$0.02546	$0.02437
2024 True-Up Refund	($0.00193)	($0.00192)	($0.00190)	($0.00241)	($0.00151)	($0.00145)
Sherco 3 Refund	($0.00188)	($0.00187)	($0.00185)	($0.00235)	($0.00147)	($0.00141)
NPTC Refund	($0.00751)	($0.00750)	($0.00739)	($0.00939)	($0.00590)	($0.00564)
Total	$0.02112	$0.02112	$0.02079	$0.02643	$0.01658	$0.01587
October						
Forecast	$0.03080	$0.03077	$0.03031	$0.03852	$0.02418	$0.02315
2024 True-Up Refund	($0.00200)	($0.00200)	($0.00197)	($0.00250)	($0.00157)	($0.00150)
Sherco 3 Refund	($0.00196)	($0.00196)	($0.00193)	($0.00245)	($0.00154)	($0.00147)
NPTC Refund	($0.00781)	($0.00780)	($0.00768)	($0.00976)	($0.00613)	($0.00587)
Total	$0.01903	$0.01901	$0.01873	$0.02381	$0.01494	$0.01431
November						
Forecast	$0.02847	$0.02844	$0.02801	$0.03560	$0.02234	$0.02139
2024 True-Up Refund	($0.00206)	($0.00206)	($0.00203)	($0.00257)	($0.00162)	($0.00155)
Sherco 3 Refund	($0.00201)	($0.00201)	($0.00198)	($0.00251)	($0.00158)	($0.00151)
NPTC Refund	($0.00802)	($0.00801)	($0.00789)	($0.01003)	($0.00630)	($0.00603)
Total	$0.01638	$0.01636	$0.01611	$0.02049	$0.01284	$0.01230
December						
Forecast	$0.02950	$0.02947	$0.02903	$0.03689	$0.02315	$0.02216
2024 True-Up Refund	($0.00182)	($0.00182)	($0.00180)	($0.00228)	($0.00143)	($0.00137)
Sherco 3 Refund	($0.00178)	($0.00178)	($0.00176)	($0.00223)	($0.00140)	($0.00134)
NPTC Refund	($0.00713)	($0.00713)	($0.00702)	($0.00892)	($0.00560)	($0.00536)
Total	$0.01877	$0.01874	$0.01845	$0.02346	$0.01472	$0.01409
January 2026						
2026 Forecast*						
2024 True-Up Refund	($0.00174)	($0.00174)	($0.00172)	($0.00218)	($0.00137)	($0.00131)
Sherco 3 Refund	($0.00170)	($0.00170)	($0.00168)	($0.00213)	($0.00134)	($0.00128)
NPTC Refund	($0.00679)	($0.00678)	($0.00668)	($0.00849)	($0.00533)	($0.00510)
Total	($0.01023)	($0.01022)	($0.01007)	($0.01280)	($0.00803)	($0.00769)
February 2026						
2026 Forecast*						
2024 True-Up Refund	($0.00201)	($0.00201)	($0.00198)	($0.00251)	($0.00158)	($0.00151)
Sherco 3 Refund	($0.00197)	($0.00197)	($0.00194)	($0.00246)	($0.00154)	($0.00148)
NPTC Refund	($0.00786)	($0.00785)	($0.00773)	($0.00983)	($0.00617)	($0.00591)
Total	($0.01183)	($0.01182)	($0.01164)	($0.01480)	($0.00929)	($0.00889)
March 2026						
2026 Forecast*						
2024 True-Up Refund	($0.00183)	($0.00183)	($0.00181)	($0.00229)	($0.00144)	($0.00138)
Sherco 3 Refund	($0.00179)	($0.00179)	($0.00177)	($0.00224)	($0.00141)	($0.00135)
NPTC Refund	($0.00718)	($0.00717)	($0.00706)	($0.00897)	($0.00563)	($0.00539)
Total	($0.01080)	($0.01079)	($0.01063)	($0.01351)	($0.00848)	($0.00812)

* 2026 Forecast is not available at time of this 2024 true-up filing.

2025 Monthly Fuel Clause Charges with 2024 Mid-Year Adj., 2024 True-Up and Other Refunds ($/KWh)

	C&I Demand		
	3-Period Time of Use		
	On-Peak	Base	Off-Peak
January			
Forecast	$0.04242	$0.03421	$0.01684
2024 Mid-Year Adjustment.	($0.00846)	($0.00683)	($0.00336)
Total	$0.03396	$0.02738	$0.01348
February			
Forecast	$0.04638	$0.03739	$0.01838
2024 Mid-Year Adjustment.	($0.00979)	($0.00789)	($0.00388)
Total	$0.03659	$0.02950	$0.01450
March			
Forecast	$0.04688	$0.03779	$0.01856
2024 Mid-Year Adjustment.	($0.00899)	($0.00724)	($0.00356)
Total	$0.03789	$0.03055	$0.01500
April			
Forecast	$0.05024	$0.04051	$0.01990
2024 True-Up Refund	($0.00295)	($0.00238)	($0.00117)
Sherco 3 Refund	($0.00288)	($0.00232)	($0.00114)
Total	$0.04441	$0.03581	$0.01759
May			
Forecast	$0.04690	$0.03782	$0.01859
2024 True-Up Refund	($0.00263)	($0.00212)	($0.00104)
Sherco 3 Refund	($0.00258)	($0.00208)	($0.00102)
NPTC Refund	($0.01029)	($0.00830)	($0.00408)
Total	$0.03140	$0.02532	$0.01245
June			
Forecast	$0.04813	$0.03879	$0.01904
2024 True-Up Refund	($0.00230)	($0.00186)	($0.00091)
Sherco 3 Refund	($0.00225)	($0.00181)	($0.00089)
NPTC Refund	($0.00897)	($0.00723)	($0.00355)
Total	$0.03461	$0.02789	$0.01369
July			
Forecast	$0.04576	$0.03687	$0.01807
2024 True-Up Refund	($0.00194)	($0.00157)	($0.00077)
Sherco 3 Refund	($0.00191)	($0.00154)	($0.00075)
NPTC Refund	($0.00762)	($0.00614)	($0.00302)
Total	$0.03429	$0.02762	$0.01353
August			
Forecast	$0.04406	$0.03551	$0.01741
2024 True-Up Refund	($0.00205)	($0.00165)	($0.00081)
Sherco 3 Refund	($0.00201)	($0.00162)	($0.00080)
NPTC Refund	($0.00802)	($0.00646)	($0.00317)
Total	$0.03198	$0.02578	$0.01263
September			
Forecast	$0.04212	$0.03395	$0.01666
2024 True-Up Refund	($0.00250)	($0.00202)	($0.00099)
Sherco 3 Refund	($0.00243)	($0.00196)	($0.00096)
NPTC Refund	($0.00975)	($0.00786)	($0.00386)
Total	$0.02744	$0.02211	$0.01085
October			
Forecast	$0.03998	$0.03223	$0.01583
2024 True-Up Refund	($0.00259)	($0.00209)	($0.00103)
Sherco 3 Refund	($0.00254)	($0.00205)	($0.00101)
NPTC Refund	($0.01013)	($0.00817)	($0.00401)
Total	$0.02472	$0.01992	$0.00978
November			
Forecast	$0.03695	$0.02979	$0.01463
2024 True-Up Refund	($0.00267)	($0.00215)	($0.00106)
Sherco 3 Refund	($0.00261)	($0.00210)	($0.00103)
NPTC Refund	($0.01041)	($0.00839)	($0.00412)
Total	$0.02126	$0.01715	$0.00842
December			
Forecast	$0.03829	$0.03087	$0.01516
2024 True-Up Refund	($0.00237)	($0.00191)	($0.00094)
Sherco 3 Refund	($0.00232)	($0.00187)	($0.00092)
NPTC Refund	($0.00926)	($0.00747)	($0.00367)
Total	$0.02434	$0.01962	$0.00963
January 2026			
2026 Forecast*			
2024 True-Up Refund	($0.00226)	($0.00182)	($0.00090)
Sherco 3 Refund	($0.00221)	($0.00178)	($0.00087)
NPTC Refund	($0.00881)	($0.00710)	($0.00349)
Total	($0.01328)	($0.01071)	($0.00526)
February 2026			
2026 Forecast*			
2024 True-Up Refund	($0.00261)	($0.00210)	($0.00103)
Sherco 3 Refund	($0.00255)	($0.00206)	($0.00101)
NPTC Refund	($0.01020)	($0.00822)	($0.00404)
Total	($0.01536)	($0.01238)	($0.00608)
March 2026			
2026 Forecast*			
2024 True-Up Refund	($0.00238)	($0.00192)	($0.00094)
Sherco 3 Refund	($0.00233)	($0.00188)	($0.00092)
NPTC Refund	($0.00931)	($0.00751)	($0.00369)
Total	($0.01402)	($0.01130)	($0.00555)

* 2026 Forecast is not available at time of this 2024 true-up filing.

		Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	2024 Total
	2024 FCA Factors													
	Approved Forecast Fuel Cost Charge													
	Docket No. E002/AA-23-153, Approval Order Dated November 9, 2023, Compliance filed November 17, 2023													
1	Residential	3.308¢	3.624¢	3.892¢	4.222¢	4.485¢	4.185¢	4.244¢	4.143¢	3.947¢	3.813¢	3.455¢	3.225¢	
2	C&I Non-Demand	3.305¢	3.621¢	3.889¢	4.219¢	4.481¢	4.181¢	4.240¢	4.139¢	3.944¢	3.809¢	3.452¢	3.222¢	
3	C&I Demand Non-TOD	3.256¢	3.567¢	3.830¢	4.155¢	4.414¢	4.118¢	4.177¢	4.077¢	3.885¢	3.752¢	3.400¢	3.173¢	
4	C&I Demand On-Peak	4.135¢	4.531¢	4.867¢	5.279¢	5.608¢	5.232¢	5.309¢	5.182¢	4.937¢	4.768¢	4.320¢	4.032¢	
5	C&I Demand Off-Peak	2.599¢	2.846¢	3.056¢	3.316¢	3.523¢	3.286¢	3.330¢	3.252¢	3.099¢	2.993¢	2.713¢	2.532¢	
6	Outdoor Lighting	2.488¢	2.725¢	2.926¢	3.174¢	3.372¢	3.146¢	3.188¢	3.113¢	2.966¢	2.865¢	2.597¢	2.424¢	
7	C&I Demand TOU Pilot Peak	4.292¢	4.703¢	5.052¢	5.480¢	5.820¢	5.431¢	5.511¢	5.379¢	5.124¢	4.949¢	4.484¢	4.185¢	
8	C&I Demand TOU Pilot Base	3.461¢	3.792¢	4.073¢	4.418¢	4.693¢	4.379¢	4.441¢	4.336¢	4.131¢	3.990¢	3.615¢	3.374¢	
9	C&I Demand TOU Pilot Off-Peak	1.705¢	1.865¢	2.002¢	2.173¢	2.309¢	2.153¢	2.178¢	2.128¢	2.029¢	1.960¢	1.777¢	1.660¢	
	2024 Mid-Year Adjustment													
	Docket No. E02/AA-23-153, 2024 Rate Adjustment Proposal filed September 30, 2024, Compliance filed October 31, 2024													
10	Residential	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	-0.745¢	-0.681¢	
11	C&I Non-Demand	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	-0.744¢	-0.680¢	
12	C&I Demand Non-TOD	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	-0.733¢	-0.670¢	
13	C&I Demand On-Peak	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	-0.931¢	-0.851¢	
14	C&I Demand Off-Peak	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	-0.585¢	-0.535¢	
15	Outdoor Lighting	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	-0.560¢	-0.512¢	
16	C&I Demand TOU Pilot Peak	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	-0.967¢	-0.883¢	
17	C&I Demand TOU Pilot Base	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	-0.779¢	-0.712¢	
18	C&I Demand TOU Pilot Off-Peak	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	-0.383¢	-0.351¢	
	2024 Forecast with Mid-year Adjustment													
19	Residential 1+10	3.308¢	3.624¢	3.892¢	4.222¢	4.485¢	4.185¢	4.244¢	4.143¢	3.947¢	3.813¢	2.710¢	2.544¢	
20	C&I Non-Demand 2+11	3.305¢	3.621¢	3.889¢	4.219¢	4.481¢	4.181¢	4.240¢	4.139¢	3.944¢	3.809¢	2.708¢	2.542¢	
21	C&I Demand Non-TOD 3+12	3.256¢	3.567¢	3.830¢	4.155¢	4.414¢	4.118¢	4.177¢	4.077¢	3.885¢	3.752¢	2.667¢	2.503¢	
22	C&I Demand On-Peak 4+13	4.135¢	4.531¢	4.867¢	5.279¢	5.608¢	5.232¢	5.309¢	5.182¢	4.937¢	4.768¢	3.389¢	3.181¢	
23	C&I Demand Off-Peak 5+14	2.599¢	2.846¢	3.056¢	3.316¢	3.523¢	3.286¢	3.330¢	3.252¢	3.099¢	2.993¢	2.128¢	1.997¢	
24	Outdoor Lighting 6+15	2.488¢	2.725¢	2.926¢	3.174¢	3.372¢	3.146¢	3.188¢	3.113¢	2.966¢	2.865¢	2.037¢	1.912¢	
25	C&I Demand TOU Pilot Peak 7+16	4.292¢	4.703¢	5.052¢	5.480¢	5.820¢	5.431¢	5.511¢	5.379¢	5.124¢	4.949¢	3.517¢	3.302¢	
26	C&I Demand TOU Pilot Base 8+17	3.461¢	3.792¢	4.073¢	4.418¢	4.693¢	4.379¢	4.441¢	4.336¢	4.131¢	3.990¢	2.836¢	2.662¢	
27	C&I Demand TOU Pilot Off-Peak 9+18	1.705¢	1.865¢	2.002¢	2.173¢	2.309¢	2.153¢	2.178¢	2.128¢	2.029¢	1.960¢	1.394¢	1.309¢	
	2023 Rate Adjustment Proposal													
	Docket No. E002/AA-22-179, 2023 Rate Adjustment Proposal filed November 21, 2023, Compliance filed December 27, 2023													
28	Residential	-0.220¢	-0.247¢	-0.233¢	-0.267¢	-0.247¢	-0.216¢	-0.185¢	-0.194¢	0.000¢	0.000¢	0.000¢	0.000¢	
29	C&I Non-Demand	-0.220¢	-0.247¢	-0.233¢	-0.267¢	-0.247¢	-0.216¢	-0.185¢	-0.193¢	0.000¢	0.000¢	0.000¢	0.000¢	
30	C&I Demand Non-TOD	-0.217¢	-0.244¢	-0.229¢	-0.262¢	-0.244¢	-0.212¢	-0.183¢	-0.190¢	0.000¢	0.000¢	0.000¢	0.000¢	
31	C&I Demand On-Peak	-0.275¢	-0.310¢	-0.292¢	-0.334¢	-0.310¢	-0.270¢	-0.232¢	-0.242¢	0.000¢	0.000¢	0.000¢	0.000¢	
32	C&I Demand Off-Peak	-0.173¢	-0.194¢	-0.183¢	-0.210¢	-0.195¢	-0.170¢	-0.145¢	-0.152¢	0.000¢	0.000¢	0.000¢	0.000¢	
33	Outdoor Lighting	-0.165¢	-0.186¢	-0.176¢	-0.200¢	-0.186¢	-0.163¢	-0.140¢	-0.146¢	0.000¢	0.000¢	0.000¢	0.000¢	
34	C&I Demand TOU Pilot Peak	-0.286¢	-0.322¢	-0.303¢	-0.347¢	-0.321¢	-0.281¢	-0.241¢	-0.251¢	0.000¢	0.000¢	0.000¢	0.000¢	
35	C&I Demand TOU Pilot Base	-0.230¢	-0.259¢	-0.244¢	-0.279¢	-0.259¢	-0.226¢	-0.194¢	-0.203¢	0.000¢	0.000¢	0.000¢	0.000¢	
36	C&I Demand TOU Pilot Off-Peak	-0.113¢	-0.127¢	-0.120¢	-0.137¢	-0.127¢	-0.111¢	-0.095¢	-0.099¢	0.000¢	0.000¢	0.000¢	0.000¢	
	2023 True-Up Refund													
	Docket No. E002/AA0-22-179, 2023 Annual True-up Compliance Report filed March 1, 2024, Compliance filed April 1, 2024													
37	Residential	0.000¢	0.000¢	0.000¢	-0.392¢	-0.362¢	-0.316¢	-0.272¢	-0.284¢	-0.570¢	-0.605¢	-0.612¢	-0.559¢	
38	C&I Non-Demand	0.000¢	0.000¢	0.000¢	-0.392¢	-0.361¢	-0.316¢	-0.272¢	-0.284¢	-0.569¢	-0.605¢	-0.611¢	-0.558¢	
39	C&I Demand Non-TOD	0.000¢	0.000¢	0.000¢	-0.386¢	-0.356¢	-0.311¢	-0.268¢	-0.280¢	-0.561¢	-0.596¢	-0.602¢	-0.550¢	
40	C&I Demand On-Peak	0.000¢	0.000¢	0.000¢	-0.491¢	-0.452¢	-0.395¢	-0.340¢	-0.356¢	-0.713¢	-0.757¢	-0.765¢	-0.698¢	
41	C&I Demand Off-Peak	0.000¢	0.000¢	0.000¢	-0.308¢	-0.284¢	-0.248¢	-0.214¢	-0.223¢	-0.447¢	-0.475¢	-0.480¢	-0.438¢	
42	Outdoor Lighting	0.000¢	0.000¢	0.000¢	-0.295¢	-0.272¢	-0.237¢	-0.204¢	-0.214¢	-0.428¢	-0.455¢	-0.460¢	-0.420¢	
43	C&I Demand TOU Pilot Peak	0.000¢	0.000¢	0.000¢	-0.509¢	-0.470¢	-0.410¢	-0.353¢	-0.369¢	-0.740¢	-0.786¢	-0.794¢	-0.725¢	
44	C&I Demand TOU Pilot Base	0.000¢	0.000¢	0.000¢	-0.411¢	-0.379¢	-0.331¢	-0.285¢	-0.298¢	-0.596¢	-0.634¢	-0.640¢	-0.584¢	
45	C&I Demand TOU Pilot Off-Peak	0.000¢	0.000¢	0.000¢	-0.202¢	-0.186¢	-0.162¢	-0.140¢	-0.146¢	-0.293¢	-0.311¢	-0.314¢	-0.287¢	
	2024 Forecast Factors with 2023 Rate Adjustment, 2023 True-up, and 2024 Rate Adjustment.													
46	Residential 19+28+37	3.088¢	3.377¢	3.659¢	3.563¢	3.876¢	3.653¢	3.787¢	3.665¢	3.377¢	3.208¢	2.098¢	1.985¢	
47	C&I Non-Demand 20+29+38	3.085¢	3.374¢	3.656¢	3.560¢	3.873¢	3.649¢	3.783¢	3.662¢	3.375¢	3.204¢	2.097¢	1.984¢	
48	C&I Demand Non-TOD 21+30+39	3.039¢	3.323¢	3.601¢	3.507¢	3.814¢	3.595¢	3.726¢	3.607¢	3.324¢	3.156¢	2.065¢	1.953¢	
49	C&I Demand On-Peak 22+31+40	3.860¢	4.221¢	4.575¢	4.454¢	4.846¢	4.567¢	4.737¢	4.584¢	4.224¢	4.011¢	2.624¢	2.483¢	
50	C&I Demand Off-Peak 23+32+41	2.426¢	2.652¢	2.873¢	2.798¢	3.044¢	2.868¢	2.971¢	2.877¢	2.652¢	2.518¢	1.648¢	1.559¢	
51	Outdoor Lighting 24+33+42	2.323¢	2.539¢	2.750¢	2.679¢	2.914¢	2.746¢	2.844¢	2.753¢	2.538¢	2.410¢	1.577¢	1.492¢	
52	C&I Demand TOU Pilot Peak 25+34+43	4.006¢	4.381¢	4.749¢	4.624¢	5.029¢	4.740¢	4.917¢	4.759¢	4.384¢	4.163¢	2.723¢	2.577¢	
53	C&I Demand TOU Pilot Base 26+35+44	3.231¢	3.533¢	3.829¢	3.728¢	4.055¢	3.822¢	3.962¢	3.835¢	3.535¢	3.356¢	2.196¢	2.078¢	
54	C&I Demand TOU Pilot Off-Peak 27+36+45	1.592¢	1.738¢	1.882¢	1.834¢	1.996¢	1.880¢	1.943¢	1.883¢	1.736¢	1.649¢	1.080¢	1.022¢	

	($000)	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	2024 Total
	Minnesota Calendar Month Retail Sales													
	Minnesota Retail Sales:													
55	Residential	796,152	643,344	639,745	573,451	600,601	753,508	973,503	873,706	740,974	621,534	653,764	801,652	8,671,934
56	C&I Non-Demand	74,385	66,927	68,717	60,123	60,018	63,132	70,616	71,118	65,279	57,570	58,445	50,516	766,846
57	C&I Demand Non-TOD	726,160	662,398	691,580	614,302	685,724	715,250	792,373	801,191	743,626	695,211	651,324	810,812	8,589,951
58	C&I Demand On-Peak	270,914	275,528	294,107	264,537	308,160	312,230	333,044	335,483	321,941	318,308	297,408	260,357	3,592,017
59	C&I Demand Off-Peak	486,776	451,104	472,035	464,384	494,030	505,559	560,068	536,526	533,937	517,298	466,767	443,449	5,931,933
60	Outdoor Lighting	12,877	10,401	9,654	8,939	6,803	7,385	6,759	7,730	8,502	9,465	10,657	11,831	111,003
61	C&I Demand TOU Pilot Peak	-	-	-	-	-	-	-	1,332	2,229	9,047	1,657	6,452	20,717
62	C&I Demand TOU Pilot Base	-	-	-	-	-	-	-	2,728	6,190	12,776	3,235	10,661	35,590
63	C&I Demand TOU Pilot Off-Peak	-	-	-	-	-	-	-	360	87	953	367	434	2,201
64	Total	2,367,264	2,109,702	2,175,838	1,985,736	2,155,336	2,357,064	2,736,363	2,630,174	2,422,765	2,242,162	2,143,624	2,396,164	27,722,192
	Less WindSource & Renewable*Connect													
65	Residential	19,901	16,790	16,040	16,972	15,042	15,755	19,167	21,209	17,487	17,554	13,930	18,494	208,341
66	C&I Non-Demand	504	474	414	377	413	483	627	658	624	560	599	665	6,398
67	C&I Demand Non-TOD	6,979	7,352	7,136	6,976	6,026	9,941	10,694	18,745	10,861	13,124	8,808	11,725	118,367
68	C&I Demand On-Peak	15,172	13,943	15,032	17,489	13,062	16,704	25,134	26,501	37,319	24,079	17,490	29,165	251,090
69	C&I Demand Off-Peak	22,059	20,205	21,784	25,344	18,929	24,207	36,424	38,405	54,082	34,895	25,316	42,265	363,915
70	Outdoor Lighting	-	-	-	-	-	-	-	-	-	-	2	-	2
71	C&I Demand TOU Pilot Peak	-	-	-	-	-	-	-	-	-	-	-	-	-
72	C&I Demand TOU Pilot Base	-	-	-	-	-	-	-	-	-	-	-	-	-
73	C&I Demand TOU Pilot Off-Peak	-	-	-	-	-	-	-	-	-	-	-	-	-
74	Total	64,615	58,764	60,406	67,158	53,472	67,090	92,046	105,518	120,373	90,212	66,145	102,314	948,113
	Minnesota FCA Calendar Month Sales:													
75	Residential 55-65	776,251	626,554	623,705	556,479	585,559	737,753	954,336	852,497	723,487	603,980	639,834	783,158	8,463,593
76	C&I Non-Demand 56-66	73,881	66,453	68,303	59,746	59,605	62,649	69,989	70,460	64,655	57,010	57,846	49,851	760,448
77	C&I Demand Non-TOD 57-67	719,181	655,046	684,444	607,326	679,698	705,309	781,679	782,446	732,765	682,087	642,516	799,087	8,471,584
78	C&I Demand On-Peak 58-68	255,742	261,585	279,075	247,048	295,098	295,526	307,910	308,982	284,622	294,229	279,918	231,192	3,340,927
79	C&I Demand Off-Peak 59-69	464,717	430,899	450,251	439,040	475,101	481,352	523,644	498,121	479,855	482,403	441,451	401,184	5,568,018
80	Outdoor Lighting 60-70	12,877	10,401	9,654	8,939	6,803	7,385	6,759	7,730	8,502	9,465	10,655	11,831	111,001
81	C&I Demand TOU Pilot Peak 61-71	-	-	-	-	-	-	-	1,332	2,229	9,047	1,657	6,452	20,717
82	C&I Demand TOU Pilot Base 62-72	-	-	-	-	-	-	-	2,728	6,190	12,776	3,235	10,661	35,590
83	C&I Demand TOU Pilot Off-Peak 63-73	-	-	-	-	-	-	-	360	87	953	367	434	2,201
84	Total	2,302,649	2,050,938	2,115,432	1,918,578	2,101,864	2,289,974	2,644,317	2,524,656	2,302,392	2,151,950	2,077,479	2,293,850	26,774,079
	Recovery Based on 2024 Forecast Factors													
85	Residential 19x75/100	$25,678	$22,706	$24,275	$23,495	$26,262	$30,875	$40,502	$35,319	$28,556	$23,030	$17,340	$19,924	$317,961
86	C&I Non-Demand 20x76/100	$2,442	$2,406	$2,656	$2,521	$2,671	$2,619	$2,968	$2,916	$2,550	$2,172	$1,566	$1,267	$28,754
87	C&I Demand Non-TOD 21x77/100	$23,417	$23,365	$26,214	$25,234	$30,002	$29,045	$32,651	$31,900	$28,468	$25,592	$17,136	$20,001	$313,025
88	C&I Demand On-Peak 22x78/100	$10,575	$11,852	$13,583	$13,042	$16,549	$15,462	$16,347	$16,011	$14,052	$14,029	$9,486	$7,354	$158,342
89	C&I Demand Off-Peak 23x79/100	$12,078	$12,263	$13,760	$14,559	$16,738	$15,817	$17,437	$16,199	$14,871	$14,438	$9,394	$8,012	$165,566
90	Outdoor Lighting 24x80/100	$320	$283	$282	$284	$229	$232	$215	$241	$252	$271	$217	$226	$3,054
91	C&I Demand TOU Pilot Peak 25x81/100	$0	$0	$0	$0	$0	$0	$0	$72	$114	$448	$58	$213	$905
92	C&I Demand TOU Pilot Base 26x82/100	$0	$0	$0	$0	$0	$0	$0	$118	$256	$510	$92	$284	$1,259
93	C&I Demand TOU Pilot Off-Peak 27x83/100	$0	$0	$0	$0	$0	$0	$0	$8	$2	$19	$5	$6	$39
94	MN 2024 Forecast Fuel Recoveries	$74,510	$72,877	$80,770	$79,134	$92,451	$94,050	$110,120	$102,784	$89,120	$80,508	$55,295	$57,286	$988,906
	2024 Under (+)/Over(-) Recovered Expense													
95	Expected Minnesota Fuel Costs Recovery	$64,356	$62,571	$72,328	$77,542	$77,138	$71,132	$76,983	$79,578	$105,031	$85,017	$62,099	$60,916	$894,690
96	Minnesota Actual Recovery **Line 94**	$74,510	$72,877	$80,770	$79,134	$92,451	$94,050	$110,120	$102,784	$89,120	$80,508	$55,295	$57,286	$988,906
97	**2024 Total Under (+)/Over(-) Recovered Exp 95-96**	**($10,154)**	**($10,306)**	**($8,442)**	**($1,592)**	**($15,313)**	**($22,919)**	**($33,137)**	**($23,206)**	**$15,910**	**$4,509**	**$6,805**	**$3,629**	**($94,216)**

	($000)	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	2024 Total
	Proposed 2023 Over-Recovery Reduction (Docket No. E002/AA-22-179, 2023 Rate Adjustment Proposal filed November 21, 2023, Compliance filed December 27, 2023)													
98	Proposed 2023 Rate Reduction	$ (5,000)	$ (5,000)	$ (5,000)	$ (5,000)	$ (5,000)	$ (5,000)	$ (5,000)	$ (5,000)					$ (40,000)
	Actual Recovery													
99	Residential 28x75/100	($1,708)	($1,548)	($1,453)	($1,486)	($1,446)	($1,594)	($1,766)	($1,654)	$0	$0	$0	$0	($12,654)
100	C&I Non-Demand 29x76/100	($163)	($164)	($159)	($160)	($147)	($135)	($129)	($136)	$0	$0	$0	$0	($1,193)
101	C&I Demand Non-TOD 30*77/100	($1,561)	($1,598)	($1,567)	($1,591)	($1,658)	($1,495)	($1,430)	($1,487)	$0	$0	$0	$0	($12,388)
102	C&I Demand On-Peak 31x78/100	($703)	($811)	($815)	($825)	($915)	($798)	($714)	($748)	$0	$0	$0	$0	($6,329)
103	C&I Demand Off-Peak 32x79/100	($804)	($836)	($824)	($922)	($926)	($818)	($759)	($757)	$0	$0	$0	$0	($6,647)
104	Outdoor Lighting 33x80/100	($21)	($19)	($17)	($18)	($13)	($12)	($9)	($11)	$0	$0	$0	$0	($121)
105	C&I Demand TOU Pilot Peak 34x81/100	$0	$0	$0	$0	$0	$0	$0	($3)	$0	$0	$0	$0	($3)
106	C&I Demand TOU Pilot Base 35x82/100	$0	$0	$0	$0	$0	$0	$0	($6)	$0	$0	$0	$0	($6)
107	C&I Demand TOU Pilot Off-Peak 36x83/100	$0	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	$0	($0)
108	2023 'Proposed Rate Reduction' Recovery	($4,959)	($4,976)	($4,836)	($5,002)	($5,106)	($4,852)	($4,809)	($4,802)	$0	$0	$0	$0	($39,342)
109	**Deferred 2023 Total Under (+)/Over(-) Recovered**	**$ (41)**	**($24)**	**($164)**	**$2**	**$106**	**($148)**	**($191)**	**$ (198)**	**$0**	**$0**	**$0**	**$0**	**$ (658)**
	Expected 2023 True Up Recovery (Docket No. E002/AA0-22-179, 2023 Annual True-up Compliance Report filed March 1, 2024, Compliance filed April 1, 2024)													
110	Expected 2023 True Up Recovery				$ (7,322)	$ (7,322)	$ (7,322)	$ (7,322)	$ (7,322)	($12,322)	($12,322)	($12,322)	($12,322)	$ (85,902)
	Actual Recovery													
111	Residential 37x75/100	$0	$0	$0	($2,181)	($2,120)	($2,331)	($2,596)	($2,421)	($4,124)	($3,654)	($3,916)	($4,378)	($27,721)
112	C&I Non-Demand 38x76/100	$0	$0	$0	($234)	($215)	($198)	($190)	($200)	($368)	($345)	($353)	($278)	($2,382)
113	C&I Demand Non-TOD 39*77/100	$0	$0	$0	($2,344)	($2,420)	($2,194)	($2,095)	($2,191)	($4,111)	($4,065)	($3,868)	($4,395)	($27,682)
114	C&I Demand On-Peak 40x78/100	$0	$0	$0	($1,213)	($1,334)	($1,167)	($1,047)	($1,100)	($2,029)	($2,227)	($2,141)	($1,614)	($13,873)
115	C&I Demand Off-Peak 41x79/100	$0	$0	$0	($1,352)	($1,349)	($1,194)	($1,121)	($1,111)	($2,145)	($2,291)	($2,119)	($1,757)	($14,439)
116	Outdoor Lighting 42x80/100	$0	$0	$0	($26)	($19)	($18)	($14)	($17)	($36)	($43)	($49)	($50)	($271)
117	C&I Demand TOU Pilot Peak 43x81/100	$0	$0	$0	$0	$0	$0	$0	($5)	($16)	($71)	($13)	($47)	($152)
118	C&I Demand TOU Pilot Base 44x82/100	$0	$0	$0	$0	$0	$0	$0	($8)	($37)	($81)	($21)	($62)	($209)
119	C&I Demand TOU Pilot Off-Peak 45x83/100	$0	$0	$0	$0	$0	$0	$0	($1)	($0)	($3)	($1)	($1)	($6)
120	2023 True Up Recovery	$0	$0	$0	($7,351)	($7,456)	($7,101)	($7,062)	($7,053)	($12,867)	($12,781)	($12,482)	($12,582)	($86,736)
121	**Deferred 2023 True-Up Under (+)/Over(-) Recovered**	**$ -**	**$0**	**$0**	**$ 29**	**$134**	**($221)**	**($260)**	**($270)**	**$544**	**$459**	**$159**	**$259**	**$ 834**
	Summary of Total True-up Under (+)/Over (-) Recovery													
122	2024 Total Under (+)/Over(-) Recovered Exp line 97	(10,154)	(10,306)	(8,442)	(1,592)	(15,313)	(22,919)	(33,137)	(23,206)	15,910	4,509	6,805	3,629	(94,216)
123	Sherco 3 Refund												(47,957)	(47,957)
124	Nuclear PTC Credits												(175,612)	(175,612)
125	2024 (Over)/Under Recovery with Refunds 122+123+124	(10,154)	(10,306)	(8,442)	(1,592)	(15,313)	(22,919)	(33,137)	(23,206)	15,910	4,509	6,805	(219,940)	(317,785)
126	Net Balance of 2023 Mid-Year adjustment line 109	(41)	(24)	(164)	2	106	(148)	(191)	(198)	0	0	0	0	(658)
127	Net Balance of 2023 True-up line 121	0	0	0	29	134	(221)	(260)	(270)	544	459	159	259	834
128	**Total to be refunded in the 2024 True-up Filing**	**$ (10,195)**	**$ (10,330)**	**$ (8,606)**	**$ (1,561)**	**$ (15,074)**	**$ (23,288)**	**$ (33,589)**	**$ (23,673)**	**$ 16,455**	**$ 4,968**	**$ 6,964**	**$ (219,680)**	**$ (317,610)**
	Proposed 2024 True-Up and Refunds Factors													
	($000)	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	2025 Total
129	2024 Total Under (+)/Over(-) Recovered 122+126+127													($94,041)
130	2024 Over-Recovery Reduction	$ 15,000	$ 15,000	$ 15,000										$ 45,000
131	**2024 Net Under (+)/Over(-) Recovered**													**($49,041)**
132	Monthly Refund Amount	$ (15,000)	$ (15,000)	$ (15,000)	$ (4,087)	$ (4,087)	$ (4,087)	$ (4,087)	$ (4,087)	$ (4,087)	$ (4,087)	$ (4,087)	(4,087)	$ (81,781)
133	2025 Forecast Net Minnesota MWh Sales				1,829,191	2,052,690	2,353,420	2,770,963	2,632,962	2,166,940	2,083,470	2,027,891	2,281,278	20,198,804
134	**2024 True Up Factor ($/kWh) 132/133**				**$ (0.00223)**	**$ (0.00199)**	**$ (0.00174)**	**$ (0.00147)**	**$ (0.00155)**	**$ (0.00189)**	**$ (0.00196)**	**$ (0.00202)**	**$ (0.00179)**	
135	Sherco 3 Outage Replacement Refund in 2025				$ (3,996)	$ (3,996)	$ (3,996)	$ (3,996)	$ (3,996)	$ (3,996)	$ (3,996)	$ (3,996)	$ (3,996)	(35,968)
136	**Sherco 3 Refund Factor ($/kWh) 135/133**				**$ (0.00218)**	**$ (0.00195)**	**$ (0.00170)**	**$ (0.00144)**	**$ (0.00152)**	**$ (0.00184)**	**$ (0.00192)**	**$ (0.00197)**	**$ (0.00175)**	
137	Nuclear PTCs Refund in 2025					$ (15,965)	$ (15,965)	$ (15,965)	$ (15,965)	$ (15,965)	$ (15,965)	$ (15,965)	$ (15,965)	(127,718)
138	**Nuclear PTCs Refund Factor ($/kWh) 137/133**					**$ (0.00778)**	**$ (0.00678)**	**$ (0.00576)**	**$ (0.00606)**	**$ (0.00737)**	**$ (0.00766)**	**$ (0.00787)**	**$ (0.00700)**	

No.		Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	2025 Total
	FAF Ratio													
139	Residential	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	
140	C&I Non-Demand	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	
141	C&I Demand Non-TOD	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	
142	C&I Demand On-Peak	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	
143	C&I Demand Off-Peak	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	
144	Outdoor Lighting	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	
145	C&I Demand TOU Pilot Peak	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	
146	C&I Demand TOU Pilot Base	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	
147	C&I Demand TOU Pilot Off-Peak	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	
	Proposed True Up Factor by Class Category													
148	Residential 134x139				$ (0.00227)	$ (0.00203)	$ (0.00177)	$ (0.00150)	$ (0.00158)	$ (0.00193)	$ (0.00200)	$ (0.00206)	$ (0.00182)	
149	C&I Non-Demand 134x140				$ (0.00227)	$ (0.00203)	$ (0.00177)	$ (0.00150)	$ (0.00158)	$ (0.00192)	$ (0.00200)	$ (0.00206)	$ (0.00182)	
150	C&I Demand Non-TOD 134x141				$ (0.00224)	$ (0.00200)	$ (0.00175)	$ (0.00147)	$ (0.00155)	$ (0.00190)	$ (0.00197)	$ (0.00203)	$ (0.00180)	
151	C&I Demand On-Peak 134x142				$ (0.00284)	$ (0.00254)	$ (0.00222)	$ (0.00187)	$ (0.00198)	$ (0.00241)	$ (0.00250)	$ (0.00257)	$ (0.00228)	
152	C&I Demand Off-Peak 134x143				$ (0.00178)	$ (0.00159)	$ (0.00139)	$ (0.00118)	$ (0.00124)	$ (0.00151)	$ (0.00157)	$ (0.00162)	$ (0.00143)	
153	Outdoor Lighting 134x144				$ (0.00171)	$ (0.00152)	$ (0.00133)	$ (0.00113)	$ (0.00119)	$ (0.00145)	$ (0.00150)	$ (0.00155)	$ (0.00137)	
154	C&I Demand TOU Pilot Peak 134x145				$ (0.00295)	$ (0.00263)	$ (0.00230)	$ (0.00194)	$ (0.00205)	$ (0.00250)	$ (0.00259)	$ (0.00267)	$ (0.00237)	
155	C&I Demand TOU Pilot Base 134x146				$ (0.00238)	$ (0.00212)	$ (0.00186)	$ (0.00157)	$ (0.00165)	$ (0.00202)	$ (0.00209)	$ (0.00215)	$ (0.00191)	
156	C&I Demand TOU Pilot Off-Peak 134x147				$ (0.00117)	$ (0.00104)	$ (0.00091)	$ (0.00077)	$ (0.00081)	$ (0.00099)	$ (0.00103)	$ (0.00106)	$ (0.00094)	
	Sherco 3 Refund Factor by Class category													
157	Residential 136x139				$ (0.00222)	$ (0.00199)	$ (0.00173)	$ (0.00147)	$ (0.00155)	$ (0.00188)	$ (0.00196)	$ (0.00201)	$ (0.00178)	
158	C&I Non-Demand 136x140				$ (0.00222)	$ (0.00199)	$ (0.00173)	$ (0.00147)	$ (0.00155)	$ (0.00187)	$ (0.00196)	$ (0.00201)	$ (0.00178)	
159	C&I Demand Non-TOD 136x141				$ (0.00219)	$ (0.00196)	$ (0.00171)	$ (0.00144)	$ (0.00152)	$ (0.00185)	$ (0.00193)	$ (0.00198)	$ (0.00176)	
160	C&I Demand On-Peak 136x142				$ (0.00278)	$ (0.00249)	$ (0.00217)	$ (0.00184)	$ (0.00194)	$ (0.00235)	$ (0.00245)	$ (0.00251)	$ (0.00223)	
161	C&I Demand Off-Peak 136x143				$ (0.00174)	$ (0.00156)	$ (0.00136)	$ (0.00115)	$ (0.00122)	$ (0.00147)	$ (0.00154)	$ (0.00158)	$ (0.00140)	
162	Outdoor Lighting 136x144				$ (0.00167)	$ (0.00149)	$ (0.00130)	$ (0.00110)	$ (0.00116)	$ (0.00141)	$ (0.00147)	$ (0.00151)	$ (0.00134)	
163	C&I Demand TOU Pilot Peak 136x145				$ (0.00288)	$ (0.00258)	$ (0.00225)	$ (0.00191)	$ (0.00201)	$ (0.00243)	$ (0.00254)	$ (0.00261)	$ (0.00232)	
164	C&I Demand TOU Pilot Base 136x146				$ (0.00232)	$ (0.00208)	$ (0.00181)	$ (0.00154)	$ (0.00162)	$ (0.00196)	$ (0.00205)	$ (0.00210)	$ (0.00187)	
165	C&I Demand TOU Pilot Off-Peak 136x147				$ (0.00114)	$ (0.00102)	$ (0.00089)	$ (0.00075)	$ (0.00080)	$ (0.00096)	$ (0.00101)	$ (0.00103)	$ (0.00092)	
	Nuclear PTC Refund Factor by Class Category													
166	Residential 138x139					$ (0.00793)	$ (0.00691)	$ (0.00587)	$ (0.00618)	$ (0.00751)	$ (0.00781)	$ (0.00802)	$ (0.00713)	
167	C&I Non-Demand 138x140					$ (0.00792)	$ (0.00690)	$ (0.00587)	$ (0.00617)	$ (0.00750)	$ (0.00780)	$ (0.00801)	$ (0.00713)	
168	C&I Demand Non-TOD 138x141					$ (0.00780)	$ (0.00680)	$ (0.00578)	$ (0.00608)	$ (0.00739)	$ (0.00768)	$ (0.00789)	$ (0.00702)	
169	C&I Demand On-Peak 138x142					$ (0.00992)	$ (0.00864)	$ (0.00734)	$ (0.00772)	$ (0.00939)	$ (0.00976)	$ (0.01003)	$ (0.00892)	
170	C&I Demand Off-Peak 138x143					$ (0.00622)	$ (0.00542)	$ (0.00461)	$ (0.00485)	$ (0.00590)	$ (0.00613)	$ (0.00630)	$ (0.00560)	
171	Outdoor Lighting 138x144					$ (0.00596)	$ (0.00519)	$ (0.00441)	$ (0.00464)	$ (0.00564)	$ (0.00587)	$ (0.00603)	$ (0.00536)	
172	C&I Demand TOU Pilot Peak 138x145					$ (0.01029)	$ (0.00897)	$ (0.00762)	$ (0.00802)	$ (0.00975)	$ (0.01013)	$ (0.01041)	$ (0.00926)	
173	C&I Demand TOU Pilot Base 138x146					$ (0.00830)	$ (0.00723)	$ (0.00614)	$ (0.00646)	$ (0.00786)	$ (0.00817)	$ (0.00839)	$ (0.00747)	
174	C&I Demand TOU Pilot Off-Peak 138x147					$ (0.00408)	$ (0.00355)	$ (0.00302)	$ (0.00317)	$ (0.00386)	$ (0.00401)	$ (0.00412)	$ (0.00367)	
	Forecast Fuel Cost Factors 2025													
175	Residential	$ 0.02617	$ 0.02819	$ 0.02919	$ 0.03871	$ 0.03614	$ 0.03707	$ 0.03524	$ 0.03393	$ 0.03244	$ 0.03080	$ 0.02847	$ 0.02950	
176	C&I Non-Demand	$ 0.02615	$ 0.02817	$ 0.02916	$ 0.03867	$ 0.03611	$ 0.03704	$ 0.03520	$ 0.03390	$ 0.03241	$ 0.03077	$ 0.02844	$ 0.02947	
177	C&I Demand Non-TOD	$ 0.02576	$ 0.02774	$ 0.02873	$ 0.03809	$ 0.03557	$ 0.03648	$ 0.03467	$ 0.03339	$ 0.03193	$ 0.03031	$ 0.02801	$ 0.02903	
178	C&I Demand On-Peak	$ 0.03272	$ 0.03525	$ 0.03651	$ 0.04841	$ 0.04519	$ 0.04637	$ 0.04408	$ 0.04245	$ 0.04058	$ 0.03852	$ 0.03560	$ 0.03689	
179	C&I Demand Off-Peak	$ 0.02056	$ 0.02213	$ 0.02291	$ 0.03039	$ 0.02838	$ 0.02909	$ 0.02764	$ 0.02662	$ 0.02546	$ 0.02418	$ 0.02234	$ 0.02315	
180	Outdoor Lighting	$ 0.01968	$ 0.02119	$ 0.02193	$ 0.02909	$ 0.02717	$ 0.02785	$ 0.02646	$ 0.02548	$ 0.02437	$ 0.02315	$ 0.02139	$ 0.02216	
181	C&I Demand TOU Pilot Peak	$ 0.03396	$ 0.03659	$ 0.03789	$ 0.05024	$ 0.04690	$ 0.04813	$ 0.04576	$ 0.04406	$ 0.04212	$ 0.03998	$ 0.03695	$ 0.03829	
182	C&I Demand TOU Pilot Base	$ 0.02738	$ 0.02950	$ 0.03055	$ 0.04051	$ 0.03782	$ 0.03879	$ 0.03687	$ 0.03551	$ 0.03395	$ 0.03223	$ 0.02979	$ 0.03087	
183	C&I Demand TOU Pilot Off-Peak	$ 0.01348	$ 0.01450	$ 0.01500	$ 0.01990	$ 0.01859	$ 0.01904	$ 0.01807	$ 0.01741	$ 0.01666	$ 0.01583	$ 0.01463	$ 0.01516	
	2025 Forecast Fuel Cost Factors With Proposed 2024 True Up and Refunds													
184	Residential 148+157+166+175	**$ 0.02617**	**$ 0.02819**	**$ 0.02919**	**$ 0.03422**	**$ 0.02419**	**$ 0.02666**	**$ 0.02640**	**$ 0.02462**	**$ 0.02112**	**$ 0.01903**	**$ 0.01638**	**$ 0.01877**	
185	C&I Non-Demand 149+158+167+176	**$ 0.02615**	**$ 0.02817**	**$ 0.02916**	**$ 0.03418**	**$ 0.02417**	**$ 0.02664**	**$ 0.02636**	**$ 0.02460**	**$ 0.02112**	**$ 0.01901**	**$ 0.01636**	**$ 0.01874**	
186	C&I Demand Non-TOD 150+159+168+177	**$ 0.02576**	**$ 0.02774**	**$ 0.02873**	**$ 0.03366**	**$ 0.02381**	**$ 0.02622**	**$ 0.02598**	**$ 0.02424**	**$ 0.02079**	**$ 0.01873**	**$ 0.01611**	**$ 0.01845**	
187	C&I Demand On-Peak 151+160+169+178	**$ 0.03272**	**$ 0.03525**	**$ 0.03651**	**$ 0.04279**	**$ 0.03024**	**$ 0.03334**	**$ 0.03303**	**$ 0.03081**	**$ 0.02643**	**$ 0.02381**	**$ 0.02049**	**$ 0.02346**	
188	C&I Demand Off-Peak 152+161+170+179	**$ 0.02056**	**$ 0.02213**	**$ 0.02291**	**$ 0.02687**	**$ 0.01901**	**$ 0.02092**	**$ 0.02070**	**$ 0.01931**	**$ 0.01658**	**$ 0.01494**	**$ 0.01284**	**$ 0.01472**	
189	Outdoor Lighting 153+162+171+180	**$ 0.01968**	**$ 0.02119**	**$ 0.02193**	**$ 0.02571**	**$ 0.01820**	**$ 0.02003**	**$ 0.01982**	**$ 0.01849**	**$ 0.01587**	**$ 0.01431**	**$ 0.01230**	**$ 0.01409**	
190	C&I Demand TOU Pilot Peak 154+163+172+181	**$ 0.03396**	**$ 0.03659**	**$ 0.03789**	**$ 0.04441**	**$ 0.03140**	**$ 0.03461**	**$ 0.03429**	**$ 0.03198**	**$ 0.02744**	**$ 0.02472**	**$ 0.02126**	**$ 0.02434**	
191	C&I Demand TOU Pilot Base 155+164+173+182	**$ 0.02738**	**$ 0.02950**	**$ 0.03055**	**$ 0.03581**	**$ 0.02532**	**$ 0.02789**	**$ 0.02762**	**$ 0.02578**	**$ 0.02211**	**$ 0.01992**	**$ 0.01715**	**$ 0.01962**	
192	C&I Demand TOU Pilot Off-Peak 156+165+174+183	**$ 0.01348**	**$ 0.01450**	**$ 0.01500**	**$ 0.01759**	**$ 0.01245**	**$ 0.01369**	**$ 0.01353**	**$ 0.01263**	**$ 0.01085**	**$ 0.00978**	**$ 0.00842**	**$ 0.00963**	

Proposed 2024 True-up and Refunds impacts on 2026 Fuel Factors

	($000)	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	2026 Total
193	2026 Forecast Net Minnesota MWh Sales	2,396,136	2,070,791	2,267,128										6,734,054
194	2024 Over-Recovery Balance	$ (4,087)	$ (4,087)	$ (4,087)										**$ (12,260)**
195	**2024 True Up Refund Factor ($/kWh) 194/193**	**$ (0.00171)**	**$ (0.00197)**	**$ (0.00180)**										
196	Sherco 3 Outage Replacement Refund Balance	$ (3,996)	$ (3,996)	$ (3,996)										**$ (11,989)**
197	**Sherco 3 Refund Factor ($/kWh) 196/193**	**$ (0.00167)**	**$ (0.00193)**	**$ (0.00176)**										
198	Nuclear PTCs Refund Balance	$ (15,965)	$ (15,965)	$ (15,965)										**$ (47,894)**
199	**Nuclear PTCs Refund Factor ($/kWh) 198/193**	**$ (0.00666)**	**$ (0.00771)**	**$ (0.00704)**										
	Proposed True Up Factor by Class Category													
200	Residential 195x139	$ (0.00174)	$ (0.00201)	$ (0.00183)										
201	C&I Non-Demand 195x140	$ (0.00174)	$ (0.00201)	$ (0.00183)										
202	C&I Demand Non-TOD 195x141	$ (0.00172)	$ (0.00198)	$ (0.00181)										
203	C&I Demand On-Peak 195x142	$ (0.00218)	$ (0.00251)	$ (0.00229)										
204	C&I Demand Off-Peak 195x143	$ (0.00137)	$ (0.00158)	$ (0.00144)										
205	Outdoor Lighting 195x144	$ (0.00131)	$ (0.00151)	$ (0.00138)										
206	C&I Demand TOU Pilot Peak 195x145	$ (0.00226)	$ (0.00261)	$ (0.00238)										
207	C&I Demand TOU Pilot Base 195x146	$ (0.00182)	$ (0.00210)	$ (0.00192)										
208	C&I Demand TOU Pilot Off-Peak 195x147	$ (0.00090)	$ (0.00103)	$ (0.00094)										
	Sherco 3 Refund Factor by Class category													
209	Residential 197x139	$ (0.00170)	$ (0.00197)	$ (0.00179)										
210	C&I Non-Demand 197x140	$ (0.00170)	$ (0.00197)	$ (0.00179)										
211	C&I Demand Non-TOD 197x141	$ (0.00168)	$ (0.00194)	$ (0.00177)										
212	C&I Demand On-Peak 197x142	$ (0.00213)	$ (0.00246)	$ (0.00224)										
213	C&I Demand Off-Peak 197x143	$ (0.00134)	$ (0.00154)	$ (0.00141)										
214	Outdoor Lighting 197x144	$ (0.00128)	$ (0.00148)	$ (0.00135)										
215	C&I Demand TOU Pilot Peak 197x145	$ (0.00221)	$ (0.00255)	$ (0.00233)										
216	C&I Demand TOU Pilot Base 197x146	$ (0.00178)	$ (0.00206)	$ (0.00188)										
217	C&I Demand TOU Pilot Off-Peak 197x147	$ (0.00087)	$ (0.00101)	$ (0.00092)										
	Nuclear PTC Refund Factor by Class Category													
218	Residential 199x139	$ (0.00679)	$ (0.00786)	$ (0.00718)										
219	C&I Non-Demand 199x140	$ (0.00678)	$ (0.00785)	$ (0.00717)										
220	C&I Demand Non-TOD 199x141	$ (0.00668)	$ (0.00773)	$ (0.00706)										
221	C&I Demand On-Peak 199x142	$ (0.00849)	$ (0.00983)	$ (0.00897)										
222	C&I Demand Off-Peak 199x143	$ (0.00533)	$ (0.00617)	$ (0.00563)										
223	Outdoor Lighting 199x144	$ (0.00510)	$ (0.00591)	$ (0.00539)										
224	C&I Demand TOU Pilot Peak 199x145	$ (0.00881)	$ (0.01020)	$ (0.00931)										
225	C&I Demand TOU Pilot Base 199x146	$ (0.00710)	$ (0.00822)	$ (0.00751)										
226	C&I Demand TOU Pilot Off-Peak 199x147	$ (0.00349)	$ (0.00404)	$ (0.00369)										

Northern States Power Company (Minnesota)
Electric Utility - State of Minnesota
Company Generation, Purchased Power and Other GWh

		Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	2024 Total
	Own Generation													
	Fossil Fuel													
1	Coal	932.4	347.1	204.2	212.5	256.9	613.4	866.4	649.0	495.7	188.2	230.9	516.6	5,513.1
2	Wood/RDF	39.8	37.0	32.3	39.7	44.6	36.7	36.9	42.8	30.7	41.7	45.6	45.2	473.0
3	Natural Gas CC	787.4	673.1	757.0	361.3	551.3	587.5	884.4	897.4	457.0	357.3	607.2	775.3	7,696.2
4	Natural Gas & Oil CT	55.5	16.4	56.9	6.5	58.3	58.5	246.4	205.5	159.0	78.7	111.3	71.5	1,124.6
5	Subtotal	1,815.1	1,073.6	1,050.3	620.0	911.1	1,296.1	2,034.1	1,794.7	1,142.4	666.0	995.1	1,408.5	14,806.9
6	Hydro	56.8	53.2	59.4	100.8	113.7	135.6	96.9	66.9	51.1	34.0	60.1	48.9	877.5
	Solar	-	-	-	-	-	-	-	-	20.0	30.7	14.9	7.1	72.7
7	Wind	754.2	809.9	1,003.5	1,090.9	820.2	736.9	433.5	598.4	788.7	950.4	839.0	822.7	9,648.3
8	Nuclear Fuel	514.2	738.5	1,024.2	1,237.3	1,204.6	1,174.3	1,260.8	1,255.7	1,078.6	860.2	735.7	871.8	11,955.8
9	Total Fuel 5+6+7+8	3,140.2	2,675.3	3,137.4	3,049.0	3,049.5	3,343.0	3,825.3	3,715.8	3,080.7	2,541.2	2,644.8	3,159.0	37,361.1
	Purchased Energy													
10	LT Purchased Energy (Gas)	321.1	343.0	304.0	209.7	223.8	355.5	694.3	604.4	477.3	303.1	498.2	445.2	4,779.5
11	LT Purchased Energy (Solar)	30.4	55.5	76.4	76.4	99.3	92.0	104.7	95.4	86.6	66.1	39.6	25.2	847.7
12	Community Solar*Gardens	50.5	107.2	150.3	137.3	184.6	162.9	175.7	186.2	178.7	136.1	66.9	49.9	1,586.4
13	LT Purchased Energy (Wind)	487.2	519.0	598.9	578.0	492.9	450.2	298.5	356.6	406.3	560.6	495.9	527.8	5,771.9
14	LT Purchased Energy (Other)	169.9	159.6	151.1	140.1	236.2	211.6	225.2	228.5	220.5	220.4	158.6	166.3	2,288.0
15	Total Purchased Energy 10+11+12+13+14	1,059.2	1,184.4	1,280.7	1,141.5	1,236.8	1,272.2	1,498.3	1,471.2	1,369.4	1,286.3	1,259.2	1,214.5	15,273.5
16	ST Market Purchase	332.2	172.3	107.1	122.1	220.7	223.8	226.1	274.4	312.7	228.4	173.0	244.1	2,636.7
17	Asset Based Sales Revenues (Market Sales)	(985.0)	(928.1)	(1,213.1)	(1,323.6)	(1,336.1)	(1,381.5)	(1,630.9)	(1,717.5)	(1,201.7)	(1,064.0)	(949.4)	(1,141.0)	(14,872.0)
18	Net Market Cost 16+17	(652.8)	(755.8)	(1,105.9)	(1,201.5)	(1,115.4)	(1,157.7)	(1,404.8)	(1,443.2)	(889.0)	(835.7)	(776.4)	(896.9)	(12,235.3)
19	MISO Cost													
20	Net MISO D2 and ASM Cost 18+19	(652.8)	(755.8)	(1,105.9)	(1,201.5)	(1,115.4)	(1,157.7)	(1,404.8)	(1,443.2)	(889.0)	(835.7)	(776.4)	(896.9)	(12,235.3)
21	**Total System GWh (At Generator) 9+15+20**	3,546.6	3,103.8	3,312.2	2,988.9	3,170.9	3,457.4	3,918.8	3,743.8	3,561.1	2,991.8	3,127.5	3,476.5	40,399.3
22	Less Solar Gardens - Above Market													
23	Less WindSource	(44.3)	(41.2)	(40.0)	-	-	-	-	-	-	-	-	-	(125.4)
24	Less Renewable*Connect	(20.4)	(17.6)	(20.4)	(67.2)	(53.5)	(67.1)	(92.0)	(105.5)	(120.4)	(90.2)	(66.1)	(102.3)	(822.7)
25	Total Costs Direct Assigned 22+23+24	(64.6)	(58.8)	(60.4)	(67.2)	(53.5)	(67.1)	(92.0)	(105.5)	(120.4)	(90.2)	(66.1)	(102.3)	(948.1)
26	**Net System GWh (At Generator) 21+25**	3,482.0	3,045.1	3,251.8	2,921.7	3,117.4	3,390.3	3,826.7	3,638.3	3,440.7	2,901.6	3,061.4	3,374.2	39,451.2

Northern States Power Company (Minnesota)
Electric Utility - State of Minnesota
Estimated Fuel Related Costs Per MWh (At Generator)

		Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	2024 Total
	Own Generation													
	Fossil Fuel													
1	Coal	$24.91	$26.92	$24.41	$28.88	$26.12	$23.46	$25.35	$25.99	$25.20	$28.40	$25.29	$23.25	$25.27
2	Wood/RDF	$3.69	$17.67	$22.73	$25.51	$15.50	$15.93	$18.18	$20.41	$12.95	$18.41	$17.82	$30.71	$18.46
3	Natural Gas CC	$26.28	$17.74	$18.25	$19.74	$18.93	$15.32	$18.82	$15.56	$49.63	$27.78	$21.46	$25.67	$21.98
4	Natural Gas & Oil CT	$35.09	$62.37	$17.34	$302.31	$30.86	$28.56	$21.82	$29.02	$34.09	$25.32	$26.52	$54.22	$31.10
5	Subtotal	$25.35	$21.39	$19.53	$26.20	$21.55	$19.79	$21.95	$20.99	$35.88	$27.08	$22.75	$26.39	$23.78
6	Hydro	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
7	Wind	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
8	Nuclear Fuel	$7.84	$8.39	$9.12	$9.08	$9.33	$8.88	$8.86	$8.90	$8.99	$8.14	$8.06	$8.23	$8.75
9	Total Fuel	$15.93	$10.90	$9.52	$9.01	$10.12	$10.79	$14.59	$13.14	$16.45	$9.85	$10.80	$14.04	$12.23
	Purchased Energy													
10	LT Purchased Energy (Gas)	$30.52	$25.52	$22.36	$21.63	$21.43	$24.18	$22.38	$20.90	$24.68	$26.92	$25.96	$31.35	$24.75
11	LT Purchased Energy (Solar)	$51.75	$58.49	$65.73	$64.83	$68.09	$69.64	$67.18	$63.63	$68.59	$71.24	$59.24	$42.57	$65.04
12	Community Solar*Gardens	$138.78	$141.37	$142.35	$142.09	$140.04	$143.02	$138.37	$141.38	$139.68	$139.93	$136.73	$132.66	$140.34
13	LT Purchased Energy (Wind)	$36.95	$39.75	$41.80	$41.01	$39.71	$31.80	$35.83	$33.77	$48.32	$39.33	$41.03	$34.32	$38.83
14	LT Purchased Energy (Other)	$82.92	$79.77	$81.83	$82.73	$84.68	$99.56	$66.91	$84.93	$84.42	$106.63	$82.24	$57.41	$83.49
15	Total Purchased Energy	$47.66	$51.10	$55.13	$56.32	$62.24	$57.92	$48.48	$51.99	$59.10	$60.22	$45.92	$40.61	$53.11
16	ST Market Purchase	$54.75	$10.73	($42.00)	$14.46	$22.78	$24.63	$52.64	$38.52	$4.65	$37.36	$16.55	$41.24	$27.77
17	Asset Based Sales Revenues (Market Sales)	$43.81	$14.65	$12.86	$5.37	$15.82	$18.40	$29.56	$22.85	$21.38	$14.16	$21.70	$30.74	$20.84
18	Net Market Cost	$38.25	$15.55	$18.18	$4.45	$14.44	$17.20	$25.85	$19.87	$27.26	$7.82	$22.84	$27.88	$19.34
19	MISO Cost													
20	Net MISO D2 and ASM Cost	$15.58	$6.38	$4.13	($8.51)	$7.58	$13.06	$19.17	$13.91	($10.26)	($15.82)	$0.17	$10.78	$5.51
21	**Total System $/MWh**	$25.47	$27.34	$28.95	$34.12	$31.35	$27.37	$25.91	$28.11	$39.52	$38.68	$27.58	$24.16	$29.72
22	Less Solar Gardens - Above Market													
23	Less WindSource	$38.12	$50.17	$76.00	-	-	-	-	-	-	-	-	-	$54.15
24	Less Renewable* Connect	$27.79	$41.22	$44.89	$2.47	$38.99	$54.72	$31.41	$30.91	$32.21	$41.36	$33.88	$28.06	$32.82
25	Total Costs Direct Assigned	$119.75	$257.95	$347.33	$246.20	$438.46	$308.28	$232.76	$215.15	$193.56	$208.96	$139.67	$135.62	$225.64
26	**Net System $/MWh**	$23.72	$22.89	$23.04	$29.25	$24.36	$21.81	$20.93	$22.69	$34.13	$33.38	$25.16	$20.78	$25.01

	FUEL COST CHARGE ($/kWh)								
	Residential	C&I Non-Demand	Non-TOD	TOD		Outdoor Lighting	General Time of Use Service Pilot Program		
				On-Peak	Off-Peak		On-Peak	Base	Off-Peak
2024 Actual Rates									
FAF Ratio *	1.0192	1.0183	1.0030	1.2746	0.8001	0.7659	1.3230	1.0665	0.5239
January									
Forecast	$0.03308	$0.03305	$0.03256	$0.04135	$0.02599	$0.02488	$0.04292	$0.03461	$0.01705
2023 Reduction	($0.00220)	($0.00220)	($0.00217)	($0.00275)	($0.00173)	($0.00165)	($0.00286)	($0.00230)	($0.00113)
Total	$0.03088	$0.03085	$0.03039	$0.03860	$0.02426	$0.02323	$0.04006	$0.03231	$0.01592
February									
Forecast	$0.03624	$0.03621	$0.03567	$0.04531	$0.02846	$0.02725	$0.04703	$0.03792	$0.01865
2023 Reduction	($0.00247)	($0.00247)	($0.00244)	($0.00310)	($0.00194)	($0.00186)	($0.00322)	($0.00259)	($0.00127)
Total	$0.03377	$0.03374	$0.03323	$0.04221	$0.02652	$0.02539	$0.04381	$0.03533	$0.01738
March									
Forecast	$0.03892	$0.03889	$0.03830	$0.04867	$0.03056	$0.02926	$0.05052	$0.04073	$0.02002
2023 Reduction	($0.00233)	($0.00233)	($0.00229)	($0.00292)	($0.00183)	($0.00176)	($0.00303)	($0.00244)	($0.00120)
Total	$0.03659	$0.03656	$0.03601	$0.04575	$0.02873	$0.02750	$0.04749	$0.03829	$0.01882
April									
Forecast	$0.04222	$0.04219	$0.04155	$0.05279	$0.03316	$0.03174	$0.05480	$0.04418	$0.02173
2023 Proposed Reduction	($0.00267)	($0.00267)	($0.00262)	($0.00334)	($0.00210)	($0.00200)	($0.00347)	($0.00279)	($0.00137)
2023 True-Up Refund	($0.00392)	($0.00392)	($0.00386)	($0.00491)	($0.00308)	($0.00295)	($0.00509)	($0.00411)	($0.00202)
Total	$0.03563	$0.03560	$0.03507	$0.04454	$0.02798	$0.02679	$0.04624	$0.03728	$0.01834
May									
Forecast	$0.04485	$0.04481	$0.04414	$0.05608	$0.03523	$0.03372	$0.05820	$0.04693	$0.02309
2023 Proposed Reduction	($0.00247)	($0.00247)	($0.00244)	($0.00310)	($0.00195)	($0.00186)	($0.00321)	($0.00259)	($0.00127)
2023 True-Up Refund	($0.00362)	($0.00361)	($0.00356)	($0.00452)	($0.00284)	($0.00272)	($0.00470)	($0.00379)	($0.00186)
Total	$0.03876	$0.03873	$0.03814	$0.04846	$0.03044	$0.02914	$0.05029	$0.04055	$0.01996
June									
Forecast	$0.04185	$0.04181	$0.04118	$0.05232	$0.03286	$0.03146	$0.05431	$0.04379	$0.02153
2023 Proposed Reduction	($0.00216)	($0.00216)	($0.00212)	($0.00270)	($0.00170)	($0.00163)	($0.00281)	($0.00226)	($0.00111)
2023 True-Up Refund	($0.00316)	($0.00316)	($0.00311)	($0.00395)	($0.00248)	($0.00237)	($0.00410)	($0.00331)	($0.00162)
Total	$0.03653	$0.03649	$0.03595	$0.04567	$0.02868	$0.02746	$0.04740	$0.03822	$0.01880
July									
Forecast	$0.04244	$0.04240	$0.04177	$0.05309	$0.03330	$0.03188	$0.05511	$0.04441	$0.02178
2023 Proposed Reduction	($0.00185)	($0.00185)	($0.00183)	($0.00232)	($0.00145)	($0.00140)	($0.00241)	($0.00194)	($0.00095)
2023 True-Up Refund	($0.00272)	($0.00272)	($0.00268)	($0.00340)	($0.00214)	($0.00204)	($0.00353)	($0.00285)	($0.00140)
Total	$0.03787	$0.03783	$0.03726	$0.04737	$0.02971	$0.02844	$0.04917	$0.03962	$0.01943
August									
Forecast	$0.04143	$0.04139	$0.04077	$0.05182	$0.03252	$0.03113	$0.05379	$0.04336	$0.02128
2023 Proposed Reduction	($0.00194)	($0.00193)	($0.00190)	($0.00242)	($0.00152)	($0.00146)	($0.00251)	($0.00203)	($0.00099)
2023 True-Up Refund	($0.00284)	($0.00284)	($0.00280)	($0.00356)	($0.00223)	($0.00214)	($0.00369)	($0.00298)	($0.00146)
Total	$0.03665	$0.03662	$0.03607	$0.04584	$0.02877	$0.02753	$0.04759	$0.03835	$0.01883
September									
Forecast	$0.03947	$0.03944	$0.03885	$0.04937	$0.03099	$0.02966	$0.05124	$0.04131	$0.02029
2023 True-Up Refund	($0.00570)	($0.00569)	($0.00561)	($0.00713)	($0.00447)	($0.00428)	($0.00740)	($0.00596)	($0.00293)
Total	$0.03377	$0.03375	$0.03324	$0.04224	$0.02652	$0.02538	$0.04384	$0.03535	$0.01736
October									
Forecast	$0.03813	$0.03809	$0.03752	$0.04768	$0.02993	$0.02865	$0.04949	$0.03990	$0.01960
2023 True-Up Refund	($0.00605)	($0.00605)	($0.00596)	($0.00757)	($0.00475)	($0.00455)	($0.00786)	($0.00634)	($0.00311)
Total	$0.03208	$0.03204	$0.03156	$0.04011	$0.02518	$0.02410	$0.04163	$0.03356	$0.01649
November									
Forecast	$0.03455	$0.03452	$0.03400	$0.04320	$0.02713	$0.02597	$0.04484	$0.03615	$0.01777
2023 True-Up Refund	($0.00612)	($0.00611)	($0.00602)	($0.00765)	($0.00480)	($0.00460)	($0.00794)	($0.00640)	($0.00314)
2024 Mid-Year Adjustment	($0.00745)	($0.00744)	($0.00733)	($0.00931)	($0.00585)	($0.00560)	($0.00967)	($0.00779)	($0.00383)
Total	$0.02098	$0.02097	$0.02065	$0.02624	$0.01648	$0.01577	$0.02723	$0.02196	$0.01080
December									
Forecast	$0.03225	$0.03222	$0.03173	$0.04032	$0.02532	$0.02424	$0.04185	$0.03374	$0.01660
2023 True-Up Refund	($0.00559)	($0.00558)	($0.00550)	($0.00698)	($0.00438)	($0.00420)	($0.00725)	($0.00584)	($0.00287)
2024 Mid-Year Adjustment	($0.00681)	($0.00680)	($0.00670)	($0.00851)	($0.00535)	($0.00512)	($0.00883)	($0.00712)	($0.00351)
Total	$0.01985	$0.01984	$0.01953	$0.02483	$0.01559	$0.01492	$0.02577	$0.02078	$0.01022
YTD Average	**$0.03278**	**$0.03275**	**$0.03226**	**$0.04099**	**$0.02574**	**$0.02464**	**$0.04254**	**$0.03430**	**$0.01686**

* FAF Ratio effective January 1, 2024.

Redline

FUEL COST FACTORS (2025)

Month	Residential	Commercial & Industrial Non-Demand	Commercial & Industrial Non-TOD	Commercial & Industrial Demand On-Peak	Commercial & Industrial Off-Peak	Outdoor Lighting
January	$0.02617	$0.02615	$0.02576	$0.03272	$0.02056	$0.01968
February	$0.02819	$0.02817	$0.02774	$0.03525	$0.02213	$0.02119
March	$0.02919	$0.02916	$0.02873	$0.03651	$0.02291	$0.02193
April	~~$0.03871~~ $0.03422	~~$0.03867~~ $0.03418	~~$0.03809~~ $0.03366	~~$0.04841~~ $0.04279	~~$0.03039~~ $0.02687	~~$0.02909~~ $0.02571
May	~~$0.03614~~ $0.02419	~~$0.03611~~ $0.02417	~~$0.03557~~ $0.02381	~~$0.04519~~ $0.03024	~~$0.02838~~ $0.01901	~~$0.02717~~ $0.01820
June	~~$0.03707~~ $0.02666	~~$0.03704~~ $0.02664	~~$0.03648~~ $0.02622	~~$0.04637~~ $0.03334	~~$0.02909~~ $0.02092	~~$0.02785~~ $0.02003
July	~~$0.03524~~ $0.02640	~~$0.03520~~ $0.02636	~~$0.03467~~ $0.02598	~~$0.04408~~ $0.03303	~~$0.02764~~ $0.02070	~~$0.02646~~ $0.01982
August	~~$0.03393~~ $0.02462	~~$0.03390~~ $0.02460	~~$0.03339~~ $0.02424	~~$0.04245~~ $0.03081	~~$0.02662~~ $0.01931	~~$0.02548~~ $0.01849
September	~~$0.03244~~ $0.02112	~~$0.03241~~ $0.02112	~~$0.03193~~ $0.02079	~~$0.04058~~ $0.02643	~~$0.02546~~ $0.01658	~~$0.02437~~ $0.01587
October	~~$0.03080~~ $0.01903	~~$0.03077~~ $0.01901	~~$0.03031~~ $0.01873	~~$0.03852~~ $0.02381	~~$0.02418~~ $0.01494	~~$0.02315~~ $0.01431
November	~~$0.02847~~ $0.01638	~~$0.02844~~ $0.01636	~~$0.02801~~ $0.01611	~~$0.03560~~ $0.02049	~~$0.02234~~ $0.01284	~~$0.02139~~ $0.01230
December	~~$0.02950~~ $0.01877	~~$0.02947~~ $0.01874	~~$0.02903~~ $0.01845	~~$0.03689~~ $0.02346	~~$0.02315~~ $0.01472	~~$0.02216~~ $0.01409

Commercial & Industrial General TOU Service Pilot Program

Month	Peak	Base	Off-Peak
January	$0.03396	$0.02738	$0.01348
February	$0.03659	$0.02950	$0.01450
March	$0.03789	$0.03055	$0.01500
April	~~$0.05024~~$0.04441	~~$0.04051~~$0.03581	~~$0.01990~~$0.01759
May	~~$0.04690~~$0.03140	~~$0.03782~~$0.02532	~~$0.01859~~$0.01245
June	~~$0.04813~~$0.03461	~~$0.03879~~$0.02789	~~$0.01904~~$0.01369
July	~~$0.04576~~$0.03429	~~$0.03687~~$0.02762	~~$0.01807~~$0.01353
August	~~$0.04406~~$0.03198	~~$0.03551~~$0.02578	~~$0.01741~~$0.01263
September	~~$0.04212~~$0.02744	~~$0.03395~~$0.02211	~~$0.01666~~$0.01085
October	~~$0.03998~~$0.02472	~~$0.03223~~$0.01992	~~$0.01583~~$0.00978
November	~~$0.03695~~$0.02126	~~$0.02979~~$0.01715	~~$0.01463~~$0.00842
December	~~$0.03829~~$0.02434	~~$0.03087~~$0.01962	~~$0.01516~~$0.00963

(Continued on Sheet No. 5-91.2)

CURRENT PERIOD COST OF ENERGY

The Current Period Cost of Energy per kWh is defined as the qualifying costs, forecasted to be incurred during the calendar month, divided by the kWh sales forecasted for the same month. Qualifying kWh sales are all kWh sales excluding intersystem, Renewable*Connect, Renewable*Connect Government, Voluntary Renewable*Connect Program Rider (Renewable*Connect Flex), and Voluntary Renewable*Connect Program Rider (Long Term) kWh sales. Qualifying costs are the sum of the following:

(Continued on Sheet No. 5-91.2)

Clean

FUEL COST FACTORS (2025)

Month	Residential	Commercial & Industrial Non-Demand	Commercial & Industrial Non-TOD	Commercial & Industrial Demand On-Peak	Commercial & Industrial Off-Peak	Outdoor Lighting	
January	$0.02617	$0.02615	$0.02576	$0.03272	$0.02056	$0.01968	
February	$0.02819	$0.02817	$0.02774	$0.03525	$0.02213	$0.02119	
March	$0.02919	$0.02916	$0.02873	$0.03651	$0.02291	$0.02193	
April	$0.03422	$0.03418	$0.03366	$0.04279	$0.02687	$0.02571	R
May	$0.02419	$0.02417	$0.02381	$0.03024	$0.01901	$0.01820	
June	$0.02666	$0.02664	$0.02622	$0.03334	$0.02092	$0.02003	
July	$0.02640	$0.02636	$0.02598	$0.03303	$0.02070	$0.01982	
August	$0.02462	$0.02460	$0.02424	$0.03081	$0.01931	$0.01849	
September	$0.02112	$0.02112	$0.02079	$0.02643	$0.01658	$0.01587	
October	$0.01903	$0.01901	$0.01873	$0.02381	$0.01494	$0.01431	
November	$0.01638	$0.01636	$0.01611	$0.02049	$0.01284	$0.01230	
December	$0.01877	$0.01874	$0.01845	$0.02346	$0.01472	$0.01409	R

Commercial & Industrial General TOU Service Pilot Program

Month	Peak	Base	Off-Peak	
January	$0.03396	$0.02738	$0.01348	
February	$0.03659	$0.02950	$0.01450	
March	$0.03789	$0.03055	$0.01500	
April	$0.04441	$0.03581	$0.01759	R
May	$0.03140	$0.02532	$0.01245	
June	$0.03461	$0.02789	$0.01369	
July	$0.03429	$0.02762	$0.01353	
August	$0.03198	$0.02578	$0.01263	
September	$0.02744	$0.02211	$0.01085	
October	$0.02472	$0.01992	$0.00978	
November	$0.02126	$0.01715	$0.00842	
December	$0.02434	$0.01962	$0.00963	R

CURRENT PERIOD COST OF ENERGY

The Current Period Cost of Energy per kWh is defined as the qualifying costs, forecasted to be incurred during the calendar month, divided by the kWh sales forecasted for the same month. Qualifying kWh sales are all kWh sales excluding intersystem, Renewable*Connect, Renewable*Connect Government, Voluntary Renewable*Connect Program Rider (Renewable*Connect Flex), and Voluntary Renewable*Connect Program Rider (Long Term) kWh sales. Qualifying costs are the sum of the following:

(Continued on Sheet No. 5-91.2)

SHERCO 3 Outage Refund Calculation

Protected Data is shaded.

Row	Month	Energy Replacement Cost	Minnesota Allocator	Allocated Energy Replacement Costs	Rate Case Dissallowance	Settlement Refunds	Beginning Balance	Ending Balance	Average Balance	Prime Rate	Interest
		$	%	$	$	$	$	$	$	%	$
	(a)	(b)	[c]	(d)	(y)	(z)	[e]=(f)+(i)	(f)=(d)+[e]+(y)+(z)	(g)=[[e]+(f)]/2	(h)	(i)=(g)x(h)/12
		[PROTECTED DATA BEGINS									[PROTECTED DATA BEGINS
(1)	Nov-11									3.250%	
(2)	Dec-11									3.250%	
(3)	Jan-12									3.250%	
(4)	Feb-12									3.250%	
(5)	Mar-12									3.250%	
(6)	Apr-12									3.250%	
(7)	May-12									3.250%	
(8)	Jun-12									3.250%	
(9)	Jul-12									3.250%	
(10)	Aug-12									3.250%	
(11)	Sep-12									3.250%	
(12)	Oct-12									3.250%	
(13)	Nov-12									3.250%	
(14)	Dec-12									3.250%	
(15)	Jan-13									3.250%	
(16)	Feb-13									3.250%	
(17)	Mar-13									3.250%	
(18)	Apr-13									3.250%	
(19)	May-13									3.250%	
(20)	Jun-13									3.250%	
(21)	Jul-13									3.250%	
(22)	Aug-13									3.250%	
(23)	Sep-13									3.250%	
(24)	Oct-13									3.250%	
(25)	Nov-13									3.250%	
(26)	Dec-13									3.250%	
(27)	Jan-14									3.250%	
(28)	Feb-14									3.250%	
(29)	Mar-14									3.250%	
(30)	Apr-14									3.250%	
(31)	May-14									3.250%	
(32)	Jun-14									3.250%	
(33)	Jul-14									3.250%	
(34)	Aug-14									3.250%	
(35)	Sep-14									3.250%	
(36)	Oct-14									3.250%	
(37)	Nov-14									3.250%	
(38)	Dec-14									3.250%	
(39)	Jan-15									3.250%	
(40)	Feb-15									3.250%	
(41)	Mar-15									3.250%	
(42)	Apr-15									3.250%	
(43)	May-15									3.250%	
(44)	Jun-15									3.250%	
(45)	Jul-15									3.250%	
(46)	Aug-15									3.250%	
(47)	Sep-15									3.250%	
(48)	Oct-15									3.250%	
(49)	Nov-15									3.250%	
(50)	Dec-15									3.371%	
(51)	Jan-16									3.500%	
(52)	Feb-16									3.500%	
(53)	Mar-16									3.500%	
(54)	Apr-16									3.500%	
(55)	May-16									3.500%	
(56)	Jun-16									3.500%	
(57)	Jul-16									3.500%	
(58)	Aug-16									3.500%	
(59)	Sep-16									3.500%	
(60)	Oct-16									3.500%	
(61)	Nov-16									3.500%	
(62)	Dec-16									3.637%	
(63)	Jan-17									3.750%	
(64)	Feb-17									3.750%	
(65)	Mar-17									3.879%	
(66)	Apr-17									4.000%	
(67)	May-17									4.000%	
(68)	Jun-17									4.133%	
(69)	Jul-17									4.250%	
(70)	Aug-17									4.250%	
(71)	Sep-17									4.250%	
(72)	Oct-17									4.250%	
(73)	Nov-17									4.250%	
(74)	Dec-17									4.395%	
(75)	Jan-18									4.500%	
(76)	Feb-18									4.500%	
(77)	Mar-18									4.581%	
(78)	Apr-18									4.750%	
(79)	May-18									4.750%	
(80)	Jun-18									4.892%	
(81)	Jul-18									5.000%	
(82)	Aug-18									5.000%	
(83)	Sep-18									5.033%	
(84)	Oct-18									5.250%	
(85)	Nov-18									5.250%	
(86)	Dec-18									5.347%	
(87)	Jan-19									5.500%	
(88)	Feb-19									5.500%	
(89)	Mar-19									5.500%	
(90)	Apr-19									5.500%	
(91)	May-19									5.500%	
(92)	Jun-19									5.500%	
(93)	Jul-19									5.500%	

SHERCO 3 Outage Refund Calculation

Protected Data is shaded.

Row	Month	Energy Replacement Cost $ (b)	Minnesota Allocator % [c]	Allocated Energy Replacement Costs $ (d)	Rate Case Dissallowance $ (y)	Settlement Refunds $ (z)	Beginning Balance $ [e]=(f)+(i)	Ending Balance $ (f)=(d)+[e]+(y)+(z)	Average Balance $ (g)=[[e]+(f)]/2	Prime Rate % (h)	Interest $ (i)=(g)x(h)/12
		[PROTECTED DATA BEGINS									[PROTECTED DATA BEGINS
(94)	Aug-19									5.250%	
(95)	Sep-19									5.150%	
(96)	Oct-19									4.992%	
(97)	Nov-19									4.750%	
(98)	Dec-19									4.750%	
(99)	Jan-20									4.750%	
(100)	Feb-20									4.750%	
(101)	Mar-20									4.298%	
(102)	Apr-20									3.250%	
(103)	May-20									3.250%	
(104)	Jun-20									3.250%	
(105)	Jul-20									3.250%	
(106)	Aug-20									3.250%	
(107)	Sep-20									3.250%	
(108)	Oct-20									3.250%	
(109)	Nov-20									3.250%	
(110)	Dec-20									3.250%	
(111)	Jan-21									3.250%	
(112)	Feb-21									3.250%	
(113)	Mar-21									3.250%	
(114)	Apr-21									3.250%	
(115)	May-21									3.250%	
(116)	Jun-21									3.250%	
(117)	Jul-21									3.250%	
(118)	Aug-21									3.250%	
(119)	Sep-21									3.250%	
(120)	Oct-21									3.250%	
(121)	Nov-21									3.250%	
(122)	Dec-21									3.250%	
(123)	Jan-22									3.250%	
(124)	Feb-22									3.250%	
(125)	Mar-22									3.371%	
(126)	Apr-22									3.500%	
(127)	May-22									3.935%	
(128)	Jun-22									4.375%	
(129)	Jul-22									4.847%	
(130)	Aug-22									5.500%	
(131)	Sep-22									5.725%	
(132)	Oct-22									6.250%	
(133)	Nov-22									6.950%	
(134)	Dec-22									7.274%	
(135)	Jan-23									7.500%	
(136)	Feb-23									7.741%	
(137)	Mar-23									7.823%	
(138)	Apr-23									8.000%	
(139)	May-23									8.226%	
(140)	Jun-23									8.250%	
(141)	Jul-23									8.290%	
(142)	Aug-23									8.500%	
(143)	Sep-23									8.500%	
(144)	Oct-23									8.500%	
(145)	Nov-23									8.500%	
(146)	Dec-23									8.500%	
(147)	Jan-24									8.500%	
(148)	Feb-24									8.500%	
(149)	Mar-24									8.500%	
(150)	Apr-24									8.500%	
(151)	May-24									8.500%	
(152)	Jun-24									8.500%	
(153)	Jul-24									8.500%	
(154)	Aug-24									8.500%	
(155)	Sep-24									8.300%	
(156)	Oct-24									8.000%	
(157)	Nov-24									7.810%	
(158)	Dec-24									7.650%	
(159)	Jan-25									7.500%	
(158)	Feb-25									7.500%	
(157)	Mar-25						47,658,945	47,658,945	47,658,945	7.500%	
									PROTECTED DATA ENDS]		PROTECTED DATA ENDS]
(160)	**Total**										**22,375,076**
		-		-		PROTECTED DATA ENDS]					
									Total		**47,956,813.42**

		PTCs ($)		
		[PROTECTED DATA BEGINS		
Monticello				
Prairie Island I				
Prairie Island II				
Total PTCs ($)				
Less Transaction Costs				
		PROTECTED DATA ENDS]		
Net Nuclear PTCs ($)		**172,681,248**		
	Allocator (IA Demand)			
Allocation to NSPW	16.1052%	27,810,660		
Allocation to NSPM	**83.8948%**	**144,870,588**		
		172,681,248		
Allocation of NSPM to State	Allocator (EEnergy)		Tax Gross-up 1/(1-T)*	Grossed up PTCs
Minnesota	**86.3791%**	**125,137,910**	**1.4033512**	**175,612,436**
North Dakota	6.5416%	9,476,854	1.3228371	12,536,334
South Dakota	7.0793%	10,255,824	1.2658228	12,982,055
		144,870,588		

* T = Composite Tax Rate in each State

I. Miscellaneous MISO Reporting Requirements

The Commission has required a variety of reporting related to MISO Day 1, Day 2, Day 3, and the Ancillary Services Market (ASM) in a variety of dockets. These reporting items are provided below.

A. Monthly MISO Charge Details

In compliance with the Commission's February 6, 2008 Order in Docket No. E,G999/AA-06-1208 (the 2006 AAA Report docket) and the April 24, 2006 Settlement Agreement in the Company's 2006 Electric Rate Case (Docket No. E002/GR-05-1428, Exhibit 46), Part B, Attachments 2-11 provide monthly MISO charge details for the 2024 reporting period.[1]

B. MISO ASM

The Commission's August 23, 2010 Order in Docket No. E002/M-08-528 requires utilities to report on costs and revenues from their participation in the MISO ancillary services market and to report all negative benefits (costs) of participation in the MISO ancillary services market.

1. Overall Market Performance to Date

During the 2024 Fuel Forecast Period, MISO continued to operate the electric system reliably and has exceeded compliance thresholds for all North American Electric Reliability Corporation (NERC) reliability standards to which they are subject. The MISO Independent Market Monitor (IMM), which is tasked with monitoring both the behavior of Market Participants and the operation of the market, stated the following:

2024 Winter saw Energy Prices fall by a third compared to the previous winter because of a roughly one-quarter fall in Natural Gas prices. Temperatures during Winter Storm Heather were quite cold, but MISO managed to avoid emergency declarations. Real-time congestion costs fell because of lower Natural Gas Prices and

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[1] The reporting formats are provided in compliance with the Commission's June 12, 2019 Order in Docket No. E002/CI-03-802. See Attachment 3 of the March 1, 2019 Joint Comments in that docket which details the agreed upon disposition of AAA reporting items.

Uplift remained low because of improvements in MISO's commitment process and the lower Natural Gas Prices.

Spring 2024 saw Energy Prices about 4 percent lower than they were for Spring 2023 and Natural Gas Prices came through one-quarter less than the prices seen in the previous Spring. Average hourly Wind Production was up 11 percent over the last year at 13.6 GW.

For the Summer of 2024, MISO saw Energy Prices 10 percent lower and Natural Gas Prices dropped an average of 15 percent compared to Summer 2023. On August 26, the Annual peak load was 122 GW, which was 3 percent lower than Summer 2023. Average hourly Wind Production increased 24 percent over last summer. Hurricane Beryl affected MISO South in July, causing extensive transmission outages and high price volatility.

In Fall 2024, Energy Prices were down 15 percent compared to Fall 2023, as Natural Gas Prices fell around 20 percent year over year. Hurricane Francine was another storm to affect MISO South where Severe Weather and Conservative Operations Alerts were activated. Lower Natural Gas Prices contributed to less Real-time Congestion and FTRs were fully funded. Day-ahead and Real-time RSG fell by 23 and 24 percent, respectively, mainly due to operational improvements and lower Natural Gas Prices.

2. *Estimated Market Benefits*

The comparison of NSP's participation in the MISO ASM market to an alternative scenario where NSP must self-supply ancillary services will always result in benefits to NSP and its ratepayers. Ancillary services are always supplied by the most economical set of resources within MISO, including periods where NSP sells excess to the market. The alternative for NSP is to self-supply ancillary services from a restricted number of NSP resources and never sell excess to the market. The results of the ASM benefit analysis continue to show an overall benefit for the 2024 Fuel Forecast reporting period and are provided in the following table.

	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Other Market Charge Types	ASM Admin Fees	Net Savings
Jan '24	78,405,500	78,718,070	312,570	15,444	28,174	268,952
Feb '24	40,666,600	40,828,790	162,190	9,805	40,413	111,971
Mar '24	43,804,500	43,920,550	116,050	22,146	28,773	65,131
Apr '24	30,364,230	30,326,600	(37,630)	24,720	37,393	(99,743)
May '24	39,333,790	39,521,170	187,380	63,904	43,971	79,505
Jun '24	51,725,870	52,181,400	455,530	89,767	34,218	331,545
Jul '24	79,915,940	80,991,330	1,075,390	142,209	41,528	891,653
Aug '24	73,012,980	73,545,220	532,240	163,150	40,743	328,347
Sep '24	52,151,100	52,384,150	233,050	122,757	39,077	71,215
Oct '24	33,856,240	34,161,860	305,620	76,018	31,514	198,088
Nov '24	75,185,610	75,765,880	580,270	49,925	33,025	497,319
Dec '24	87,125,880	87,142,840	16,960	59,549	43,599	(86,187)

The Company estimates the ASM resulted in total NSP System savings of approximately $2.65 million for the 2024 reporting period. The Minnesota jurisdictional allocation of the savings is approximately 75 percent, or $1.99 million. This is the savings associated with optimizing the generation units that are carrying ancillary services across the entire MISO footprint and does not include any additional benefits that have accrued to ratepayers from reducing the regional regulation reserve requirement.

3. Excessive Deficient Energy Deployment Charges

The Excessive Deficient Energy Deployment Charge (EDEDC) amount represents the charge to a generator that was not able to maintain actual generator output to within a tolerance band around the set point. During the hours where a generator was unable to meet this requirement, MISO assesses a charge equal to any day ahead or real time payments to the generator for carrying regulation reserve plus the generator's pro rata share of costs to procure regulation from all resources within MISO. Part B, Attachment 13 shows the EDEDCs assessed to each NSP System resource by month during the reporting period.

A certain level of EDEDCs is unavoidable given the current design of the ASM market. Currently for each generator, the Company can only submit a single ramp rate value that represents the average rate at which the generator can increase or decrease output across its entire dispatchable range. For a typical coal unit, the ramp rate varies significantly as the unit moves from minimum load to full load. For example, a coal generator with a minimum capability of 200 MW and a maximum capability of 400 MW might be able to operate to 300 MW with one coal pulverizer in operation, while a generator with a capability between 300 MW and 400 MW would require two coal pulverizers to be in operation. The unit might be able to ramp at a rate of 10 MW/minute up to 300 MW, then slow to 3 MW/minute while the second pulverizer is starting, and then ramp at 5 MW/minute up to 400 MW. The Company could offer only 3 MW/minute of ramp capability to MISO for dispatch, which would ensure that the unit would be able to follow its dispatch instruction close to 100 percent of the time, but would drastically under-represent the capability of the unit over most of its dispatchable range.

Offers with low ramp rates mean that the unit will not be able to clear for as much regulation reserve or spinning reserve, and therefore will not be available to fully hedge the Company's cost to procure these services. Low ramp rates also limit the unit's ability to respond to increasing or decreasing LMP prices, which ultimately leads to higher purchase power costs in the market. A more prudent strategy would be to offer 5 or 6 MW/minute of ramp capability for the entire range to strike an appropriate balance between incurring penalties during the limited intervals that the unit would not be able to "keep up," and ensuring the unit can provide sufficient quantities of ancillary and load following services to hedge exposure to market prices.

The ASM benefit calculation is a measure of the extent to which the Company has struck the *appropriate balance* between too much or too little flexibility being offered to MISO. For the 2024 Fuel Forecast reporting period, the net benefit for the Company was approximately $2.65 million[2] while the amount incurred in EDEDCs was $0.81 million. The $2.65 million in gross benefits would not have been achievable if the Company had been offering ramp rates for its units that would have all but eliminated the chance of incurring an Excessive Deficient Energy charge.

[2] The $2.65 million in ASM benefits calculated by the Company for 2024 does not include all of the savings made possible by offering high flexibility to MISO. In addition to the ASM related benefits, increased ramp rates and flexibility minimizes overall price volatility in the market, increases the ability to integrate intermittent resources such as wind, and limits uneconomic market purchases or sales.

To minimize the incurrence of excessive charges, generation unit performance to MISO setpoints is monitored in real time by the system dispatcher to ensure that plants are keeping up with offered ramp rates. Computer displays show the dispatcher a graphical depiction of actual unit output compared to setpoint along with calculations of the deviation. The system analyst and system dispatcher communicate with the plants daily to discuss operational issues affecting unit performance and adjust offers to MISO accordingly. This iterative process helps ensure that these charges are, to the extent possible, minimized while still creating opportunities for lower overall costs for ratepayers. For these reasons, a certain level of Excessive Deficient Energy Deployment Charges is expected, and prudent, in light of the overwhelming benefits associated with high unit flexibility that more than offset these charges.

4. *Contingency Reserve Deployment Failure Charges*

The Contingency Reserve Deployment Failure Charge (CRDFC) represents the charge incurred by generation or demand response resources that fail to deploy contingency reserves at or above the contingency reserve deployment instruction. This charge is assessed if a unit that is selected to provide spinning or supplemental reserves during a specific hour does not perform and MISO must then deploy another resource.

Part B, Attachment 14 shows NSP incurred a total of $14,383 in CRDFC during the 2024 Fuel Reporting period. NSP carries reserves on units with Automatic Generation Control (AGC) and units without AGC. For units without AGC, a phone call to the facility is required to deploy the reserves, adding to the time from receiving the signal and deployment. When deploying a large amount of reserves on many facilities, that action requires many more steps and time becomes critical. Additionally, MISO must meet Disturbance Control Standards within 15 minutes but does not always provide market participants the remaining time between the deployment signal and the end of the 15-minute timeframe to deploy reserves. Instead, MISO holds participants to a 10-minute response regardless if MISO has 15 minutes to meet the standard or less than 10 minutes.

The charges were not the result of any improper action by the Company, but simply reflect the fact that generating units are sometimes not able to deliver every requested MW. The Company attempts to minimize these occurrences, as evidenced by the limited charges incurred over the reporting period. Had a similar situation occurred before the start of ASM, the Company would have been required to deploy reserves from another generator in its fleet and would have incurred increased energy costs that were recovered in the FCA. Thus, it is reasonable for the Company to recover these minor charges from MISO.

The Company tests all resources capable of providing supplemental reserve response every two months to validate capability and readiness if called on by MISO during a contingency. If a resource fails to perform during a test, plant management will address the issue with any required maintenance to return the unit to reliable service. The offer to MISO for the unit to provide reserves will be adjusted accordingly to ensure the capabilities of the unit are not overstated during this time.

In short, CRDFCs are prudently incurred for the same reasons described above regarding Excessive Deficient Energy Deployment charges. Generators are complicated mechanical machines whose performance varies based on many conditions. The benefits of making these units available to provide significant amounts of spinning and supplemental reserves to hedge the Company's cost to procure ancillary services more than offsets the cost of the extremely infrequent circumstances where the unit may not be able to provide 100 percent of the amount required. Also, Xcel Energy is working to modify the rules which evaluate failure to deploy so that this charge is only applied when a unit fails compared to its offered physical capability.

5. Conclusion

The analysis performed by the Company and described above captures only the benefit associated with a more optimal assignment of reserves in the MISO footprint; *i.e.*, freeing up low-cost generation resources to provide energy while carrying reserves on higher cost resources. When combined with the benefits estimated by MISO of a decreasing regulation requirement, the Ancillary Services Market has helped to reduce ratepayer fuel costs significantly during the reporting period.

C. Schedule 10 Administrative Charge Paid to MISO Under MISO Tariff

The Commission's May 9, 2002 Order in Docket Nos. E002/M-00-257, *et al.* and August 16, 2013 Order in Docket No. E999/AA-11-792 require the Company to provide the Schedule 10 Administrative Charges Paid to MISO Under the MISO Tariff, including the allocation factor used and support for why the allocator is reasonable.

Schedule 10 Administrative Charges Paid to MISO Under MISO Tariff
Calendar Year 2024

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
January	$1,043,460.94	86.9638%	83.8948%	$761,289.46
February	$ 840,785.12	86.9638%	83.8948%	$613,421.00
March	$1,031,481.73	86.9638%	83.8948%	$752,549.66
April	$ 997,810.58	86.9638%	83.8948%	$727,983.82
May	$ 875,379.35	86.9638%	83.8948%	$638,660.30
June	$1,092,843.89	86.9638%	83.8948%	$797,318.34
July	$1,129,665.41	86.9638%	83.8948%	$824,182.62
August	$1,343,592.41	86.9638%	83.8948%	$980,259.74
September	$1,216,853.57	86.9638%	83.8948%	$887,793.46
October	$1,285,213.45	86.9638%	83.8948%	$937,667.55
November	$1,201,550.46	86.9638%	83.8948%	$876,628.60
December	$1,099,543.08	86.9638%	83.8948%	$802,205.94
Total	$13,158,179.99			**$9,599,960.49**

*The month shown is the MISO billing month. For the Company, these costs are recorded in the Company's books and records the following month. The demand allocators are shown are preliminary at the time of this filing.

For comparison purposes, we also provide the data for calendar year 2023, below.

Schedule 10 Administrative Charges Paid to MISO Under MISO Tariff
Calendar Year 2023

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
January	$ 791,898.03	87.1503%	83.8765%	$578,866.54
February	$ 760,541.12	87.1503%	83.8765%	$555,945.07
March	$ 1,018,613.72	87.1503%	83.8765%	$744,592.59
April	$ 1,171,174.98	87.1503%	83.8765%	$856,112.76
May	$ 1,014,223.30	87.1503%	83.8765%	$741,383.25
June	$ 1,048,071.03	87.1503%	83.8765%	$766,125.47
July	$ 1,205,454.81	87.1503%	83.8765%	$881,170.85
August	$ 1,446,233.00	87.1503%	83.8765%	$1,057,176.38
September	$ 1,177,963.17	87.1503%	83.8765%	$861,074.84
October	$ 1,238,887.50	87.1503%	83.8765%	$905,609.68
November	$ 737,720.19	87.1503%	83.8765%	$539,263.29
December	$ 664,176.65	87.1503%	83.8765%	$485,503.97
Total	**$12,274,957.50**			**$8,927,379.03**

*The month shown is the MISO billing month. For the Company, these costs are recorded in the Company's books and records the following month. The demand allocators are shown for the month when Schedule 10 costs are recorded on the Company's books and records.

The charges shown are the totals billed to the integrated system of the Company (NSP-Minnesota) and Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin) (collectively, the NSP System).

MISO Schedule 10 charges are recorded to FERC Accounts based on instructions from MISO in their letter dated May 12, 2006. As indicated in their instructions, Schedule 10 costs are allocated to the following accounts:

Percent	FERC Class	FERC Account	FERC Account Description
90.4%	Transmission	561.4	Scheduling, System Control and Dispatch Services
6.5%	Transmission	561.8	Reliability Planning and Standards Development Services
3.1%	Regional Market	575.7	Market Facilities, Monitoring and Compliance Services

The Company allocates costs recorded in these accounts between the NSP-Minnesota and NSP-Wisconsin Companies, as well as to NSP-Minnesota jurisdictions (Minnesota, North Dakota and South Dakota), based on a demand allocator. The Interchange Agreement demand allocator (36 month coincident peak demand) increased the NSP System allocation to the Company effective January 1, 2024, pursuant to the annual update to the Interchange Agreement allocation factors accepted by FERC in Docket No. ER24-1472-000, letter order dated May 7, 2024.

The State of Minnesota jurisdictional demand allocator (12 month coincident peak demand) decreased effective January 1, 2024 based on State of Minnesota demands. The net impact of the increase in the 2024 Interchange Agreement demand allocator and the decrease in the 2024 State of Minnesota jurisdictional demand allocator is a decrease in the 2024 NSP System allocation to the Minnesota jurisdiction.

The August 16, 2013 Order in Docket No. E999/AA-11-792 also requires utilities to provide information to support increases in MISO Schedule 10 costs of five percent or higher over the prior year's costs, including an explanation of benefits received by customers for these added costs. The MISO Schedule 10 administative charges increased $883,222 or approximately 7.2 percent from 2023 to 2024. The increase in MISO Schedule 10 costs is due to an increase in Schedule 10-D and 10-E rates from MISO.

D. Congestion Costs

The August 16, 2013 Order in Docket No. E999/AA-11-792 also requires that utilities provide data relating to congested paths, including related costs and revenues. We provide the requested analysis and discussion below.

The ten generation-load paths with the highest congestion costs, determined using a load allocation method as NSP bids in at multiple load nodes, are as follows:

Generation Node	Load Node	Total Congestion Cost
[PROTECTED DATA BEGINS		
		PROTECTED DATA ENDS]

NSP's FTR portfolio for these Generation-Load Node pairs (in MW) during the reporting period was:

Generation Node	Load Node	Winter 2023-24	
[PROTECTED DATA BEGINS		**Peak**	**Off Peak**
			PROTECTED DATA ENDS]

Generation Node	Load Node	Spring 2024	
[PROTECTED DATA BEGINS		Peak	Off Peak
			PROTECTED DATA ENDS]

Generation Node	Load Node	Summer 2024	
[PROTECTED DATA BEGINS		Peak	Off Peak
			PROTECTED DATA ENDS]

Generation Node	Load Node	Fall 2024	
[PROTECTED DATA BEGINS		Peak	Off Peak
			PROTECTED DATA ENDS]

Generation Node	Load Node	Winter 2024-25	
[PROTECTED DATA BEGINS		Peak	Off Peak
			PROTECTED DATA ENDS]

The Company uses FTRs as a hedging mechanism to manage the risk of congestion charges that may arise from the use of the transmission system in the Day-Ahead market. In order to minimize our customers' exposure to congestion costs, the Company nominates in the Stage 1a step of the FTR Auction **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. Through this nomination approach, the Company minimizes risk to net congestion costs for its most critical generation units.

During the Stage 1b step of the FTR auction, NSP nominates **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. This approach has resulted in offsetting some congestion costs with FTR revenues but cannot completely offset congestion due to the limited amount of FTR that MISO makes available to NSP, and thus does not fully cover the installed generator capacity to load node paths.

Below are the FTR Revenues, Congestion Expense, and the Net Revenue/ (Cost) of each of the ten Generation-Load Pairs identified in the tables above.

Award Node	Load Location	FTR Revenue	Congestion Cost	Net Revenue/(Cost)
[PROTECTED DATA BEGINS				
				PROTECTED DATA ENDS]

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

January 2024 Actual

		System	Intersystem	System Retail	Minnesota Retail
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (26,290,785)	$ 39,837,859	$ 13,547,074	$ 9,511,447
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 8,438,717	$ -	$ 8,438,717	$ 5,924,852
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 11,807	$ -	$ 11,807	$ 8,290
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (8,499,387)	$ -	$ (8,499,387)	$ (5,967,448)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 191,457	$ -	$ 191,457	$ 134,423
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (11,807)	$ -	$ (11,807)	$ (8,290)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 472,065	$ 1,813,700	$ 2,285,765	$ 1,604,843
13 c	Real-Time Asset Energy Amount - Loss Component	$ 21,765	$ -	$ 21,765	$ 15,281
14	Real-Time Distribution of Losses Amount	$ (1,877,644)	$ -	$ (1,877,644)	$ (1,318,301)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (802)	$ -	$ (802)	$ (563)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 35,764	$ -	$ 35,764	$ 25,110
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ -	$ -	$ -
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 17,234,539	$ -	$ 17,234,539	$ 12,100,428
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 39,043	$ -	$ 39,043	$ 27,412
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (1,549,328)	$ -	$ (1,549,328)	$ (1,087,788)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (39,043)	$ -	$ (39,043)	$ (27,412)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 65,987	$ -	$ 65,987	$ 46,330
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ -	$ -	$ -	$ -
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (6,403,839)	$ -	$ (6,403,839)	$ (4,496,157)
30	Financial Transmission Rights Monthly Allocation Amount	$ (501,954)	$ -	$ (501,954)	$ (352,424)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (672,102)	$ -	$ (672,102)	$ (471,885)
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 62,538	$ -	$ 62,538	$ 43,908
37	Financial Transmission Guarantee Uplift Amount	$ 7,396	$ -	$ 7,396	$ 5,193
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,779,997	$ -	$ 1,779,997	$ 1,249,742
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 121,773	$ -	$ 121,773	$ 85,497
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (390,394)	$ 206,515	$ (183,878)	$ (129,102)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 455,656	$ -	$ 455,656	$ 319,917
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (499,147)	$ 296,167	$ (202,979)	$ (142,512)
43	Real Time Price Volatility Make Whole Payment	$ (120,998)	$ 26,332	$ (94,666)	$ (66,465)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 534,014	$ (63,851)	$ 470,162	$ 330,103
19	Real-Time Market Administration Amount	$ 61,661	$ (2,312)	$ 59,349	$ 41,669
29	Financial Transmission Rights Market Administration Amount	$ 14,076	$ -	$ 14,076	$ 9,883
33	Day-Ahead Schedule 24 Allocation Amount	$ 104,778	$ (12,370)	$ 92,408	$ 64,880
34	Real -Time Schedule 24 Allocation Amount	$ 12,099	$ (518)	$ 11,581	$ 8,131
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ 171,967	$ -	$ 171,967	$ 120,739
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 5,449,448	$ -	$ 5,449,448	$ 3,826,076
40	Auction Revenue Rights - Monthly ARR Revenue	$ (5,468,626)	$ -	$ (5,468,626)	$ (3,839,541)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (1,256,028)	$ -	$ (1,256,028)	$ (881,862)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 85,853	$ -	$ 85,853	$ 60,278
	TOTAL MISO CHARGES	**$ (18,209,486)**	**$ 42,101,523**	**$ 23,892,037**	**$ 16,774,680**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 543,587**	**$ 381,654**
	SCHEDULE 24 (FOR RETAIL)			**$ 103,989**	**$ 73,011**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 23,244,461**	**$ 16,320,015**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	February 2024 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (8,193,773)	$ 12,705,855	$ 4,512,082	$ 3,192,960
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,945,375	$ -	$ 2,945,375	$ 2,084,285
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 5,394	$ -	$ 5,394	$ 3,817
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,647,908)	$ -	$ (3,647,908)	$ (2,581,430)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 67,874	$ -	$ 67,874	$ 48,031
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (5,394)	$ -	$ (5,394)	$ (3,817)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,549,596)	$ 961,663	$ (587,934)	$ (416,049)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 32,506	$ -	$ 32,506	$ 23,003
14	Real-Time Distribution of Losses Amount	$ (444,130)	$ -	$ (444,130)	$ (314,287)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 57,996	$ -	$ 57,996	$ 41,040
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 1,029	$ -	$ 1,029	$ 728
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ -	$ -	$ -
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 10,231,349	$ -	$ 10,231,349	$ 7,240,181
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 29,683	$ -	$ 29,683	$ 21,005
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 9,163	$ -	$ 9,163	$ 6,484
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (29,683)	$ -	$ (29,683)	$ (21,005)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 70,160	$ -	$ 70,160	$ 49,649
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ -	$ -	$ -	$ -
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,253,003)	$ -	$ (1,253,003)	$ (886,684)
30	Financial Transmission Rights Monthly Allocation Amount	$ 367,019	$ -	$ 367,019	$ 259,720
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ 0	$ -	$ 0	$ 0
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 227,045	$ -	$ 227,045	$ 160,668
37	Financial Transmission Guarantee Uplift Amount	$ (250,280)	$ -	$ (250,280)	$ (177,110)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 409,305	$ -	$ 409,305	$ 289,643
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 68,877	$ -	$ 68,877	$ 48,741
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ 3,038	$ (8,602)	$ (5,564)	$ (3,937)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ (89,633)	$ -	$ (89,633)	$ (63,429)
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (573)	$ 1,482	$ 909	$ 643
43	Real Time Price Volatility Make Whole Payment	$ (420,308)	$ 89,172	$ (331,137)	$ (234,328)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 775,220	$ (93,263)	$ 681,958	$ 482,585
19	Real-Time Market Administration Amount	$ 90,313	$ (9,309)	$ 81,003	$ 57,322
29	Financial Transmission Rights Market Administration Amount	$ 22,577	$ -	$ 22,577	$ 15,976
33	Day-Ahead Schedule 24 Allocation Amount	$ 91,655	$ (11,038)	$ 80,617	$ 57,048
34	Real -Time Schedule 24 Allocation Amount	$ 10,520	$ (1,110)	$ 9,410	$ 6,659
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (3,772,710)	$ -	$ (3,772,710)	$ (2,669,746)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 5,449,448	$ -	$ 5,449,448	$ 3,856,284
40	Auction Revenue Rights - Monthly ARR Revenue	$ (5,468,626)	$ -	$ (5,468,626)	$ (3,869,856)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (1,256,028)	$ -	$ (1,256,028)	$ (888,824)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 85,853	$ -	$ 85,853	$ 60,753
	TOTAL MISO CHARGES	**$ (5,330,246)**	**$ 13,634,848**	**$ 8,304,603**	**$ 5,876,725**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 785,538**	**$ 555,883**
	SCHEDULE 24 (FOR RETAIL)			**$ 90,027**	**$ 63,708**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 7,429,037**	**$ 5,257,134**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

			System		Intersystem		System Retail		Minnesota Retail
	March 2024 Actual								
Energy and Loss Charges									
1 a	Day-Ahead Asset Energy Amount - Energy Component	$	(13,208,706)	$	14,438,532	$	1,229,826	$	866,430
1 c	Day-Ahead Asset Energy Amount - Loss Component	$	2,930,254	$	-	$	2,930,254	$	2,064,406
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$	2,065	$	-	$	2,065	$	1,455
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$	(3,530,048)	$	-	$	(3,530,048)	$	(2,486,969)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$	102,525	$	-	$	102,525	$	72,230
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$	(2,352)	$	-	$	(2,352)	$	(1,657)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 a	Real-Time Asset Energy Amount - Energy Component	$	(575,531)	$	1,071,289	$	495,758	$	349,269
13 c	Real-Time Asset Energy Amount - Loss Component	$	36,876	$	-	$	36,876	$	25,980
14	Real-Time Distribution of Losses Amount	$	(1,130,969)	$	-	$	(1,130,969)	$	(796,784)
16	Real-Time Financial Bilateral Transaction Loss Amount	$	-	$	-	$	-	$	-
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$	-	$	-	$	-	$	-
21	Real-time Net inadvertent Distribution	$	(420,130)	$	-	$	(420,130)	$	(295,987)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$	60,056	$	-	$	60,056	$	42,310
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$	-	$	-	$	-	$	-
Congestion Related Charges									
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$	16,296,454	$	-	$	16,296,454	$	11,481,085
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$	25,319	$	-	$	25,319	$	17,837
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$	583,004	$	-	$	583,004	$	410,735
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$	(24,807)	$	-	$	(24,807)	$	(17,477)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 b	Real-Time Asset Energy Amount - Congestion Component	$	71,523	$	-	$	71,523	$	50,389
15	Real-Time Financial Bilateral Transaction Congestion Amount	$	-	$	-	$	-	$	-
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$	-	$	-	$	-	$	-
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$	-	$	-	$	-	$	-
FTR Related Charges									
28	Financial Transmission Rights Hourly Allocation Amount	$	(1,967,141)	$	-	$	(1,967,141)	$	(1,385,879)
30	Financial Transmission Rights Monthly Allocation Amount	$	(330,451)	$	-	$	(330,451)	$	(232,808)
31	Financial Transmission Rights Transaction Amount	$	-	$	-	$	-	$	-
32	Financial Transmission Rights Yearly Allocation Amount	$	-	$	-	$	-	$	-
36	Financial Transmission Rights Full Funding Guarantee Amount	$	(254,146)	$	-	$	(254,146)	$	(179,049)
37	Financial Transmission Guarantee Uplift Amount	$	250,023	$	-	$	250,023	$	176,145
38	Financial Transmission Rights Monthly Transaction Amount	$	-	$	-	$	-	$	-
Uplift (RNU) Charges									
23	Real-Time Revenue Neutrality Uplift Amount	$	1,050,618	$	-	$	1,050,618	$	740,175
Revenue Sufficiency Guarantee (RSG) Charges									
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$	61,809	$	-	$	61,809	$	43,545
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$	(95,486)	$	86,986	$	(8,500)	$	(5,989)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$	31,564	$	-	$	31,564	$	22,237
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$	(33,000)	$	23,054	$	(9,946)	$	(7,007)
43	Real Time Price Volatility Make Whole Payment	$	(92,518)	$	49,466	$	(43,052)	$	(30,330)
Market Administration Charges									
4	Day-Ahead Market Administration Amount	$	547,667	$	(82,020)	$	465,647	$	328,055
19	Real-Time Market Administration Amount	$	50,580	$	(6,851)	$	43,729	$	30,808
29	Financial Transmission Rights Market Administration Amount	$	17,146	$	-	$	17,146	$	12,080
33	Day-Ahead Schedule 24 Allocation Amount	$	98,654	$	(14,772)	$	83,882	$	59,096
34	Real -Time Schedule 24 Allocation Amount	$	9,542	$	(1,231)	$	8,311	$	5,855
35	Schedule 24 Admin Allocation	$	-	$	-	$	-	$	-
Virtual Energy Charges									
12	Day-Ahead Virtual Energy Amount	$	-	$	-	$	-	$	-
27	Real-Time Virtual Energy Amount	$	-	$	-	$	-	$	-
Other MISO Charges									
20	Real-Time Miscellaneous Amount	$	110,578	$	-	$	110,578	$	77,904
26	Real-Time Uninstructed Deviation Amount	$	-	$	-	$	-	$	-
Auction Revenue Rights (ARR)									
39	Auction Revenue Rights - FTR Auction Transactions	$	4,814,922	$	-	$	4,814,922	$	3,392,182
40	Auction Revenue Rights - Monthly ARR Revenue	$	(4,838,171)	$	-	$	(4,838,171)	$	(3,408,560)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$	(1,016,112)	$	-	$	(1,016,112)	$	(715,865)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$	122,929	$	-	$	122,929	$	86,605
	TOTAL MISO CHARGES	**$**	**(245,456)**	**$**	**15,564,452**	**$**	**15,318,996**	**$**	**10,792,452**
	SCHEDULE 16 & 17 (FOR RETAIL)					**$**	**526,522**	**$**	**370,943**
	SCHEDULE 24 (FOR RETAIL)					**$**	**92,193**	**$**	**64,951**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)					**$**	**14,700,281**	**$**	**10,356,558**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	April 2024 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (1,273,002)	$ 5,430,160	$ 4,157,158	$ 2,939,554
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,658,966	$ -	$ 2,658,966	$ 1,880,173
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 837	$ -	$ 837	$ 592
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,896,504)	$ -	$ (3,896,504)	$ (2,755,244)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 129,122	$ -	$ 129,122	$ 91,303
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (837)	$ -	$ (837)	$ (592)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (447,288)	$ 1,521,299	$ 1,074,011	$ 759,441
13 c	Real-Time Asset Energy Amount - Loss Component	$ 36,543	$ -	$ 36,543	$ 25,840
14	Real-Time Distribution of Losses Amount	$ (664,137)	$ -	$ (664,137)	$ (469,616)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 194,526	$ -	$ 194,526	$ 137,550
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 734	$ -	$ 734	$ 519
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ -	$ -	$ -
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 24,143,989	$ -	$ 24,143,989	$ 17,072,375
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 43,681	$ -	$ 43,681	$ 30,887
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,053,224	$ -	$ 1,053,224	$ 744,741
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (43,681)	$ -	$ (43,681)	$ (30,887)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 218,284	$ -	$ 218,284	$ 154,350
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ -	$ -	$ -	$ -
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (9,478,401)	$ -	$ (9,478,401)	$ (6,702,240)
30	Financial Transmission Rights Monthly Allocation Amount	$ (1,184,374)	$ -	$ (1,184,374)	$ (837,479)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (1,480,239)	$ -	$ (1,480,239)	$ (1,046,687)
37	Financial Transmission Guarantee Uplift Amount	$ 1,460,939	$ -	$ 1,460,939	$ 1,033,040
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 740,008	$ -	$ 740,008	$ 523,265
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 65,228	$ -	$ 65,228	$ 46,123
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (66,275)	$ 60,652	$ (5,623)	$ (3,976)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 29,988	$ -	$ 29,988	$ 21,204
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (52,524)	$ 35,697	$ (16,828)	$ (11,899)
43	Real Time Price Volatility Make Whole Payment	$ (395,573)	$ 113,806	$ (281,766)	$ (199,239)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 732,365	$ (120,967)	$ 611,398	$ 432,324
19	Real-Time Market Administration Amount	$ 75,966	$ (13,732)	$ 62,234	$ 44,006
29	Financial Transmission Rights Market Administration Amount	$ 16,523	$ -	$ 16,523	$ 11,684
33	Day-Ahead Schedule 24 Allocation Amount	$ 99,104	$ (16,659)	$ 82,446	$ 58,298
34	Real -Time Schedule 24 Allocation Amount	$ 10,267	$ (1,909)	$ 8,358	$ 5,910
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ 168,905	$ -	$ 168,905	$ 119,434
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 4,814,922	$ -	$ 4,814,922	$ 3,404,664
40	Auction Revenue Rights - Monthly ARR Revenue	$ (4,838,171)	$ -	$ (4,838,171)	$ (3,421,102)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (1,016,414)	$ -	$ (1,016,414)	$ (718,713)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 122,731	$ -	$ 122,731	$ 86,784
	TOTAL MISO CHARGES	**$ 11,979,433**	**$ 7,008,347**	**$ 18,987,780**	**$ 13,426,385**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 690,155**	**$ 488,013**
	SCHEDULE 24 (FOR RETAIL)			**$ 90,804**	**$ 64,208**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 18,206,821**	**$ 12,874,164**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	May 2024 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (11,807,427)	$ 18,869,743	$ 7,062,316	$ 5,105,961
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,477,396	$ -	$ 2,477,396	$ 1,791,125
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,480	$ -	$ 1,480	$ 1,070
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (7,255,552)	$ -	$ (7,255,552)	$ (5,245,668)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 176,302	$ -	$ 176,302	$ 127,464
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,480)	$ -	$ (1,480)	$ (1,070)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 766,827	$ 1,768,214	$ 2,535,041	$ 1,832,801
13 c	Real-Time Asset Energy Amount - Loss Component	$ 2,820	$ -	$ 2,820	$ 2,039
14	Real-Time Distribution of Losses Amount	$ (230,895)	$ -	$ (230,895)	$ (166,934)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 220,404	$ -	$ 220,404	$ 159,349
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (533)	$ -	$ (533)	$ (386)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ -	$ -	$ -
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 7,534,311	$ -	$ 7,534,311	$ 5,447,207
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 14,044	$ -	$ 14,044	$ 10,154
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,020,032	$ -	$ 1,020,032	$ 737,469
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (14,044)	$ -	$ (14,044)	$ (10,154)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 130,001	$ -	$ 130,001	$ 93,989
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ -	$ -	$ -	$ -
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ 392,791	$ -	$ 392,791	$ 283,983
30	Financial Transmission Rights Monthly Allocation Amount	$ 770,859	$ -	$ 770,859	$ 557,321
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (280,222)	$ -	$ (280,222)	$ (202,597)
37	Financial Transmission Guarantee Uplift Amount	$ 291,287	$ -	$ 291,287	$ 210,597
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 451,059	$ -	$ 451,059	$ 326,110
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 50,714	$ -	$ 50,714	$ 36,665
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (113,348)	$ 46,731	$ (66,617)	$ (48,163)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 36,831	$ -	$ 36,831	$ 26,628
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 1,118	$ 262	$ 1,380	$ 997
43	Real Time Price Volatility Make Whole Payment	$ (217,487)	$ 95,922	$ (121,565)	$ (87,890)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 672,568	$ (112,549)	$ 560,019	$ 404,886
19	Real-Time Market Administration Amount	$ 74,750	$ (9,956)	$ 64,794	$ 46,845
29	Financial Transmission Rights Market Administration Amount	$ 16,608	$ -	$ 16,608	$ 12,008
33	Day-Ahead Schedule 24 Allocation Amount	$ 97,855	$ (16,399)	$ 81,456	$ 58,892
34	Real -Time Schedule 24 Allocation Amount	$ 10,879	$ (1,455)	$ 9,424	$ 6,813
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ 176,367	$ -	$ 176,367	$ 127,511
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 4,814,922	$ -	$ 4,814,922	$ 3,481,125
40	Auction Revenue Rights - Monthly ARR Revenue	$ (4,838,171)	$ -	$ (4,838,171)	$ (3,497,933)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (6,098,486)	$ -	$ (6,098,486)	$ (4,409,124)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 736,335	$ -	$ 736,335	$ 532,361
	TOTAL MISO CHARGES	**$ (9,919,083)**	**$ 20,640,511**	**$ 10,721,428**	**$ 7,751,450**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 641,421**	**$ 463,739**
	SCHEDULE 24 (FOR RETAIL)			**$ 90,880**	**$ 65,705**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 9,989,127**	**$ 7,222,006**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

			System		Intersystem		System Retail		Minnesota Retail
	June 2024 Actual								
Energy and Loss Charges									
1 a	Day-Ahead Asset Energy Amount - Energy Component	$	(14,541,433)	$	23,390,473	$	8,849,040	$	6,379,530
1 c	Day-Ahead Asset Energy Amount - Loss Component	$	2,695,410	$	-	$	2,695,410	$	1,943,199
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$	(2,234)	$	-	$	(2,234)	$	(1,610)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$	(9,158,942)	$	-	$	(9,158,942)	$	(6,602,947)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$	405,412	$	-	$	405,412	$	292,274
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$	2,234	$	-	$	2,234	$	1,610
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 a	Real-Time Asset Energy Amount - Energy Component	$	(623,602)	$	1,419,722	$	796,120	$	573,946
13 c	Real-Time Asset Energy Amount - Loss Component	$	111,454	$	-	$	111,454	$	80,350
14	Real-Time Distribution of Losses Amount	$	(1,232,637)	$	-	$	(1,232,637)	$	(888,644)
16	Real-Time Financial Bilateral Transaction Loss Amount	$	-	$	-	$	-	$	-
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$	-	$	-	$	-	$	-
21	Real-time Net inadvertent Distribution	$	(128,324)	$	-	$	(128,324)	$	(92,513)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$	2,467	$	-	$	2,467	$	1,778
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$	-	$	-	$	-	$	-
Congestion Related Charges									
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$	5,364,627	$	-	$	5,364,627	$	3,867,515
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$	(16)	$	-	$	(16)	$	(11)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$	2,065,864	$	-	$	2,065,864	$	1,489,341
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$	16	$	-	$	16	$	11
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 b	Real-Time Asset Energy Amount - Congestion Component	$	507,995	$	-	$	507,995	$	366,228
15	Real-Time Financial Bilateral Transaction Congestion Amount	$	-	$	-	$	-	$	-
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$	-	$	-	$	-	$	-
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$	-	$	-	$	-	$	-
FTR Related Charges									
28	Financial Transmission Rights Hourly Allocation Amount	$	(486,341)	$	-	$	(486,341)	$	(350,617)
30	Financial Transmission Rights Monthly Allocation Amount	$	382,449	$	-	$	382,449	$	275,719
31	Financial Transmission Rights Transaction Amount	$	-	$	-	$	-	$	-
32	Financial Transmission Rights Yearly Allocation Amount	$	-	$	-	$	-	$	-
36	Financial Transmission Rights Full Funding Guarantee Amount	$	43,128	$	-	$	43,128	$	31,092
37	Financial Transmission Guarantee Uplift Amount	$	10,650	$	-	$	10,650	$	7,678
38	Financial Transmission Rights Monthly Transaction Amount	$	-	$	-	$	-	$	-
Uplift (RNU) Charges									
23	Real-Time Revenue Neutrality Uplift Amount	$	1,064,074	$	-	$	1,064,074	$	767,122
Revenue Sufficiency Guarantee (RSG) Charges									
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$	42,191	$	-	$	42,191	$	30,417
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$	(109,716)	$	58,560	$	(51,156)	$	(36,880)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$	31,815	$	-	$	31,815	$	22,936
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$	(41,559)	$	11,666	$	(29,893)	$	(21,551)
43	Real Time Price Volatility Make Whole Payment	$	(42,799)	$	19,150	$	(23,649)	$	(17,049)
Market Administration Charges									
4	Day-Ahead Market Administration Amount	$	634,612	$	(101,330)	$	533,281	$	384,458
19	Real-Time Market Administration Amount	$	64,581	$	(7,161)	$	57,419	$	41,395
29	Financial Transmission Rights Market Administration Amount	$	17,865	$	-	$	17,865	$	12,879
33	Day-Ahead Schedule 24 Allocation Amount	$	104,863	$	(16,718)	$	88,145	$	63,546
34	Real -Time Schedule 24 Allocation Amount	$	10,688	$	(1,207)	$	9,481	$	6,835
35	Schedule 24 Admin Allocation	$	-	$	-	$	-	$	-
Virtual Energy Charges									
12	Day-Ahead Virtual Energy Amount	$	-	$	-	$	-	$	-
27	Real-Time Virtual Energy Amount	$	-	$	-	$	-	$	-
Other MISO Charges									
20	Real-Time Miscellaneous Amount	$	170,437	$	-	$	170,437	$	122,873
26	Real-Time Uninstructed Deviation Amount	$	-	$	-	$	-	$	-
Auction Revenue Rights (ARR)									
39	Auction Revenue Rights - FTR Auction Transactions	$	4,224,471	$	-	$	4,224,471	$	3,045,544
40	Auction Revenue Rights - Monthly ARR Revenue	$	(4,227,298)	$	-	$	(4,227,298)	$	(3,047,582)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$	(4,353,376)	$	-	$	(4,353,376)	$	(3,138,475)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$	(497,602)	$	-	$	(497,602)	$	(358,736)
	TOTAL MISO CHARGES	**$**	**(17,488,579)**	**$**	**24,773,154**	**$**	**7,284,575**	**$**	**5,251,661**
	SCHEDULE 16 & 17 (FOR RETAIL)					**$**	**608,565**	**$**	**438,733**
	SCHEDULE 24 (FOR RETAIL)					**$**	**97,626**	**$**	**70,381**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)					**$**	**6,578,384**	**$**	**4,742,548**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	July 2024 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (32,432,600)	$ 46,116,199	$ 13,683,599	$ 9,869,694
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,089,691	$ -	$ 3,089,691	$ 2,228,530
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,437	$ -	$ 1,437	$ 1,036
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (12,202,275)	$ -	$ (12,202,275)	$ (8,801,247)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 381,164	$ -	$ 381,164	$ 274,926
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,437)	$ -	$ (1,437)	$ (1,036)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (227,224)	$ 1,509,270	$ 1,282,045	$ 924,713
13 c	Real-Time Asset Energy Amount - Loss Component	$ 78,063	$ -	$ 78,063	$ 56,305
14	Real-Time Distribution of Losses Amount	$ (775,314)	$ -	$ (775,314)	$ (559,218)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 8,725	$ -	$ 8,725	$ 6,293
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 2,754,378	$ -	$ 2,754,378	$ 1,986,675
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 7,065	$ -	$ 7,065	$ 5,096
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 4,905,582	$ -	$ 4,905,582	$ 3,538,294
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 32,272	$ -	$ 32,272	$ 23,277
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 128,299	$ -	$ 128,299	$ 92,540
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (32,272)	$ -	$ (32,272)	$ (23,277)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 150,142	$ -	$ 150,142	$ 108,294
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 47,645	$ -	$ 47,645	$ 34,365
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (873,678)	$ -	$ (873,678)	$ (630,166)
30	Financial Transmission Rights Monthly Allocation Amount	$ (36,779)	$ -	$ (36,779)	$ (26,528)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (4,187)	$ -	$ (4,187)	$ (3,020)
37	Financial Transmission Guarantee Uplift Amount	$ 4,014	$ -	$ 4,014	$ 2,895
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,236,876	$ -	$ 1,236,876	$ 892,133
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 74,320	$ -	$ 74,320	$ 53,605
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ 3,668	$ 3,020	$ 6,688	$ 4,824
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 108,665	$ -	$ 108,665	$ 78,378
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (225,583)	$ 196,953	$ (28,630)	$ (20,650)
43	Real Time Price Volatility Make Whole Payment	$ (84,253)	$ 16,130	$ (68,123)	$ (49,136)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 744,087	$ (125,269)	$ 618,817	$ 446,340
19	Real-Time Market Administration Amount	$ 58,824	$ (4,831)	$ 53,992	$ 38,944
29	Financial Transmission Rights Market Administration Amount	$ 29,086	$ -	$ 29,086	$ 20,979
33	Day-Ahead Schedule 24 Allocation Amount	$ 111,945	$ (18,966)	$ 92,980	$ 67,064
34	Real -Time Schedule 24 Allocation Amount	$ 8,842	$ (722)	$ 8,120	$ 5,857
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ 168,213	$ -	$ 168,213	$ 121,328
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 4,224,471	$ -	$ 4,224,471	$ 3,047,023
40	Auction Revenue Rights - Monthly ARR Revenue	$ (4,227,298)	$ -	$ (4,227,298)	$ (3,049,062)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (1,179,431)	$ -	$ (1,179,431)	$ (850,699)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 14,501	$ -	$ 14,501	$ 10,460
	TOTAL MISO CHARGES	**$ (33,930,359)**	**$ 47,691,783**	**$ 13,761,424**	**$ 9,925,828**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 701,896**	**$ 506,263**
	SCHEDULE 24 (FOR RETAIL)			**$ 101,099**	**$ 72,921**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 12,958,429**	**$ 9,346,644**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	August 2024 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (24,025,047)	$ 36,818,440	$ 12,793,393	$ 9,184,504
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,036,565	$ -	$ 3,036,565	$ 2,179,980
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (644)	$ -	$ (644)	$ (462)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (10,952,060)	$ -	$ (10,952,060)	$ (7,862,592)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 392,057	$ -	$ 392,057	$ 281,461
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 644	$ -	$ 644	$ 462
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,302,042)	$ 1,586,460	$ 284,417	$ 204,186
13 c	Real-Time Asset Energy Amount - Loss Component	$ 128,913	$ -	$ 128,913	$ 92,548
14	Real-Time Distribution of Losses Amount	$ (1,394,179)	$ -	$ (1,394,179)	$ (1,000,895)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (75,399)	$ -	$ (75,399)	$ (54,130)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (2,607,507)	$ -	$ (2,607,507)	$ (1,871,955)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 7,793	$ -	$ 7,793	$ 5,594
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 7,974,030	$ -	$ 7,974,030	$ 5,724,635
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 17,932	$ -	$ 17,932	$ 12,873
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,389,965	$ -	$ 1,389,965	$ 997,870
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (17,932)	$ -	$ (17,932)	$ (12,873)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 178,440	$ -	$ 178,440	$ 128,104
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (14,514)	$ -	$ (14,514)	$ (10,419)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (607,257)	$ -	$ (607,257)	$ (435,956)
30	Financial Transmission Rights Monthly Allocation Amount	$ (91,243)	$ -	$ (91,243)	$ (65,505)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (95,458)	$ -	$ (95,458)	$ (68,530)
37	Financial Transmission Guarantee Uplift Amount	$ 88,116	$ -	$ 88,116	$ 63,259
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 931,449	$ -	$ 931,449	$ 668,697
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 71,704	$ -	$ 71,704	$ 51,477
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (76,318)	$ 18,343	$ (57,975)	$ (41,621)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 144,420	$ -	$ 144,420	$ 103,680
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (12,760)	$ 15,434	$ 2,674	$ 1,920
43	Real Time Price Volatility Make Whole Payment	$ (229,929)	$ 31,315	$ (198,614)	$ (142,587)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 736,971	$ (134,880)	$ 602,091	$ 432,247
19	Real-Time Market Administration Amount	$ 64,980	$ (6,131)	$ 58,849	$ 42,249
29	Financial Transmission Rights Market Administration Amount	$ 23,341	$ -	$ 23,341	$ 16,757
33	Day-Ahead Schedule 24 Allocation Amount	$ 111,848	$ (20,245)	$ 91,603	$ 65,762
34	Real -Time Schedule 24 Allocation Amount	$ 9,864	$ (929)	$ 8,935	$ 6,415
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ 133,231	$ -	$ 133,231	$ 95,648
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 4,224,471	$ -	$ 4,224,471	$ 3,032,790
40	Auction Revenue Rights - Monthly ARR Revenue	$ (4,227,298)	$ -	$ (4,227,298)	$ (3,034,819)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ -	$ -	$ -	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ -	$ -	$ -	$ -
	TOTAL MISO CHARGES	**$ (26,062,854)**	**$ 38,307,808**	**$ 12,244,954**	**$ 8,790,774**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 684,282**	**$ 491,253**
	SCHEDULE 24 (FOR RETAIL)			**$ 100,538**	**$ 72,177**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 11,460,134**	**$ 8,227,344**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	September 2024 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (16,661,083)	$ 24,545,087	$ 7,884,004	$ 5,689,674
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,744,015	$ -	$ 3,744,015	$ 2,701,955
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (853)	$ -	$ (853)	$ (615)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (8,927,074)	$ -	$ (8,927,074)	$ (6,442,430)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 264,851	$ -	$ 264,851	$ 191,136
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 853	$ -	$ 853	$ 615
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (552,312)	$ 709,081	$ 156,769	$ 113,136
13 c	Real-Time Asset Energy Amount - Loss Component	$ 65,969	$ -	$ 65,969	$ 47,608
14	Real-Time Distribution of Losses Amount	$ (805,437)	$ -	$ (805,437)	$ (581,262)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (78,126)	$ -	$ (78,126)	$ (56,381)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 137,544	$ -	$ 137,544	$ 99,262
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (3,188)	$ -	$ (3,188)	$ (2,301)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 30,624,988	$ -	$ 30,624,988	$ 22,101,232
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 44,054	$ -	$ 44,054	$ 31,793
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 2,667,787	$ -	$ 2,667,787	$ 1,925,270
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (44,054)	$ -	$ (44,054)	$ (31,793)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 168,013	$ -	$ 168,013	$ 121,250
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 291	$ -	$ 291	$ 210
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (7,682,234)	$ -	$ (7,682,234)	$ (5,544,062)
30	Financial Transmission Rights Monthly Allocation Amount	$ (282,571)	$ -	$ (282,571)	$ (203,924)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (154,263)	$ -	$ (154,263)	$ (111,327)
37	Financial Transmission Guarantee Uplift Amount	$ 149,508	$ -	$ 149,508	$ 107,896
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,399,705	$ -	$ 1,399,705	$ 1,010,129
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 86,314	$ -	$ 86,314	$ 62,290
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (131,488)	$ 34,898	$ (96,590)	$ (69,706)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 70,807	$ -	$ 70,807	$ 51,099
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (563,053)	$ 82,232	$ (480,821)	$ (346,996)
43	Real Time Price Volatility Make Whole Payment	$ (39,554)	$ 9,992	$ (29,562)	$ (21,334)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 745,518	$ (108,076)	$ 637,443	$ 460,025
19	Real-Time Market Administration Amount	$ 69,203	$ (3,014)	$ 66,189	$ 47,767
29	Financial Transmission Rights Market Administration Amount	$ 17,074	$ -	$ 17,074	$ 12,322
33	Day-Ahead Schedule 24 Allocation Amount	$ 117,712	$ (15,858)	$ 101,854	$ 73,506
34	Real -Time Schedule 24 Allocation Amount	$ 10,921	$ (432)	$ 10,489	$ 7,570
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ 107,135	$ -	$ 107,135	$ 77,316
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,426,682	$ -	$ 7,426,682	$ 5,359,637
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,439,189)	$ -	$ (7,439,189)	$ (5,368,663)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ 5,882,331	$ -	$ 5,882,331	$ 4,245,120
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 100,943	$ -	$ 100,943	$ 72,848
	TOTAL MISO CHARGES	**$ 10,537,737**	**$ 25,253,911**	**$ 35,791,648**	**$ 25,829,872**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 720,706**	**$ 520,114**
	SCHEDULE 24 (FOR RETAIL)			**$ 112,344**	**$ 81,075**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 34,958,599**	**$ 25,228,683**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	October 2024 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 1,288,349	$ 13,675,313	$ 14,963,662	$ 10,674,925
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,336,685	$ -	$ 3,336,685	$ 2,380,357
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (590)	$ -	$ (590)	$ (421)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (9,335,330)	$ -	$ (9,335,330)	$ (6,659,730)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 334,034	$ -	$ 334,034	$ 238,296
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 590	$ -	$ 590	$ 421
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (830,768)	$ 810,345	$ (20,423)	$ (14,569)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 29,335	$ -	$ 29,335	$ 20,927
14	Real-Time Distribution of Losses Amount	$ (775,165)	$ -	$ (775,165)	$ (552,995)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (111,037)	$ -	$ (111,037)	$ (79,213)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 39,174	$ -	$ 39,174	$ 27,946
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (6)	$ -	$ (6)	$ (4)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 16,687,045	$ -	$ 16,687,045	$ 11,904,369
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 38,818	$ -	$ 38,818	$ 27,693
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,373,903	$ -	$ 1,373,903	$ 980,128
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (38,818)	$ -	$ (38,818)	$ (27,693)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 107,804	$ -	$ 107,804	$ 76,906
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 645	$ -	$ 645	$ 460
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (992,924)	$ -	$ (992,924)	$ (708,342)
30	Financial Transmission Rights Monthly Allocation Amount	$ (101,726)	$ -	$ (101,726)	$ (72,570)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 202,004	$ -	$ 202,004	$ 144,107
37	Financial Transmission Guarantee Uplift Amount	$ (189,775)	$ -	$ (189,775)	$ (135,383)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,693,229	$ -	$ 1,693,229	$ 1,207,933
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 50,466	$ -	$ 50,466	$ 36,002
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (87,639)	$ 19,964	$ (67,675)	$ (48,279)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 14,929	$ -	$ 14,929	$ 10,650
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 28,234	$ 48,787	$ 77,021	$ 54,946
43	Real Time Price Volatility Make Whole Payment	$ (34,184)	$ 27,470	$ (6,714)	$ (4,790)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 657,536	$ (94,919)	$ 562,617	$ 401,365
19	Real-Time Market Administration Amount	$ 69,217	$ (4,839)	$ 64,378	$ 45,926
29	Financial Transmission Rights Market Administration Amount	$ 14,525	$ -	$ 14,525	$ 10,362
33	Day-Ahead Schedule 24 Allocation Amount	$ 99,292	$ (14,663)	$ 84,629	$ 60,373
34	Real -Time Schedule 24 Allocation Amount	$ 10,451	$ (740)	$ 9,711	$ 6,928
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ 84,671	$ -	$ 84,671	$ 60,404
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,426,682	$ -	$ 7,426,682	$ 5,298,120
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,439,189)	$ -	$ (7,439,189)	$ (5,307,042)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (1,194,256)	$ -	$ (1,194,256)	$ (851,970)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 187,951	$ -	$ 187,951	$ 134,082
	TOTAL MISO CHARGES	**$ 12,644,162**	**$ 14,466,717**	**$ 27,110,879**	**$ 19,340,626**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 641,520**	**$ 457,654**
	SCHEDULE 24 (FOR RETAIL)			**$ 94,340**	**$ 67,301**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 26,375,019**	**$ 18,815,671**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	November 2024 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (14,365,890)	$ 19,164,082	$ 4,798,191	$ 3,379,891
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,431,515	$ -	$ 3,431,515	$ 2,417,192
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 372	$ -	$ 372	$ 262
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (4,337,498)	$ -	$ (4,337,498)	$ (3,055,374)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 141,231	$ -	$ 141,231	$ 99,484
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (800)	$ -	$ (800)	$ (564)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (68,969)	$ 687,150	$ 618,182	$ 435,453
13 c	Real-Time Asset Energy Amount - Loss Component	$ 24,945	$ -	$ 24,945	$ 17,571
14	Real-Time Distribution of Losses Amount	$ (515,596)	$ -	$ (515,596)	$ (363,191)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (52,363)	$ -	$ (52,363)	$ (36,885)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (10,954)	$ -	$ (10,954)	$ (7,716)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (148)	$ -	$ (148)	$ (104)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 14,488,275	$ -	$ 14,488,275	$ 10,205,678
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 7,698	$ -	$ 7,698	$ 5,423
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 496,730	$ -	$ 496,730	$ 349,901
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (9,355)	$ -	$ (9,355)	$ (6,590)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 75,497	$ -	$ 75,497	$ 53,181
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (143)	$ -	$ (143)	$ (100)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ 315,309	$ -	$ 315,309	$ 222,107
30	Financial Transmission Rights Monthly Allocation Amount	$ (119,782)	$ -	$ (119,782)	$ (84,376)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (27,540)	$ -	$ (27,540)	$ (19,400)
37	Financial Transmission Guarantee Uplift Amount	$ 27,540	$ -	$ 27,540	$ 19,400
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,369,617	$ -	$ 1,369,617	$ 964,771
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 64,038	$ -	$ 64,038	$ 45,109
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (197,250)	$ 70,855	$ (126,395)	$ (89,034)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 18,574	$ -	$ 18,574	$ 13,084
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (3,221)	$ (229)	$ (3,450)	$ (2,430)
43	Real Time Price Volatility Make Whole Payment	$ (84,924)	$ 24,613	$ (60,311)	$ (42,484)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 632,602	$ (79,903)	$ 552,698	$ 389,326
19	Real-Time Market Administration Amount	$ 66,577	$ (5,297)	$ 61,280	$ 43,166
29	Financial Transmission Rights Market Administration Amount	$ 12,439	$ -	$ 12,439	$ 8,762
33	Day-Ahead Schedule 24 Allocation Amount	$ 103,918	$ (13,640)	$ 90,278	$ 63,592
34	Real -Time Schedule 24 Allocation Amount	$ 10,944	$ (896)	$ 10,048	$ 7,078
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ 118,317	$ -	$ 118,317	$ 83,343
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,426,682	$ -	$ 7,426,682	$ 5,231,425
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,439,189)	$ -	$ (7,439,189)	$ (5,240,235)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (1,194,256)	$ -	$ (1,194,256)	$ (841,245)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 187,951	$ -	$ 187,951	$ 132,394
	TOTAL MISO CHARGES	**$ 592,894**	**$ 19,846,734**	**$ 20,439,628**	**$ 14,397,867**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 626,417**	**$ 441,254**
	SCHEDULE 24 (FOR RETAIL)			**$ 100,325**	**$ 70,670**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 19,712,885**	**$ 13,885,943**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	December 2024 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (28,501,836)	$ 31,941,927	$ 3,440,091	$ 2,408,758
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 5,197,331	$ -	$ 5,197,331	$ 3,639,180
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 6,439	$ -	$ 6,439	$ 4,508
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,617,654)	$ -	$ (5,617,654)	$ (3,933,491)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 130,997	$ -	$ 130,997	$ 91,724
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (6,439)	$ -	$ (6,439)	$ (4,508)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 263,806	$ 2,667,129	$ 2,930,935	$ 2,052,246
13 c	Real-Time Asset Energy Amount - Loss Component	$ 32,006	$ -	$ 32,006	$ 22,410
14	Real-Time Distribution of Losses Amount	$ (1,057,933)	$ -	$ (1,057,933)	$ (740,767)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 142,516	$ -	$ 142,516	$ 99,790
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 166,103	$ -	$ 166,103	$ 116,306
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 89	$ -	$ 89	$ 62
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 12,869,689	$ -	$ 12,869,689	$ 9,011,379
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 29,704	$ -	$ 29,704	$ 20,799
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (84,760)	$ -	$ (84,760)	$ (59,349)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (29,704)	$ -	$ (29,704)	$ (20,799)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 185,172	$ -	$ 185,172	$ 129,658
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (101)	$ -	$ (101)	$ (71)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,575,777)	$ -	$ (1,575,777)	$ (1,103,362)
30	Financial Transmission Rights Monthly Allocation Amount	$ (106,822)	$ -	$ (106,822)	$ (74,797)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (7,531)	$ -	$ (7,531)	$ (5,273)
37	Financial Transmission Guarantee Uplift Amount	$ 7,531	$ -	$ 7,531	$ 5,273
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 622,847	$ -	$ 622,847	$ 436,119
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 70,858	$ -	$ 70,858	$ 49,615
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (10,962)	$ 4,793	$ (6,169)	$ (4,320)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 93,909	$ -	$ 93,909	$ 65,755
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (205,133)	$ 39,414	$ (165,719)	$ (116,037)
43	Real Time Price Volatility Make Whole Payment	$ (144,951)	$ 40,775	$ (104,176)	$ (72,944)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 812,500	$ (101,926)	$ 710,574	$ 497,545
19	Real-Time Market Administration Amount	$ 86,284	$ (11,220)	$ 75,064	$ 52,560
29	Financial Transmission Rights Market Administration Amount	$ 4,640	$ -	$ 4,640	$ 3,249
33	Day-Ahead Schedule 24 Allocation Amount	$ 116,207	$ (15,223)	$ 100,984	$ 70,709
34	Real -Time Schedule 24 Allocation Amount	$ 12,349	$ (1,633)	$ 10,716	$ 7,504
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ 156,831	$ -	$ 156,831	$ 109,814
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,089,351	$ -	$ 7,089,351	$ 4,963,976
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,098,113)	$ -	$ (7,098,113)	$ (4,970,111)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (1,213,949)	$ -	$ (1,213,949)	$ (850,010)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 132,984	$ -	$ 132,984	$ 93,116
	TOTAL MISO CHARGES	**$ (17,431,524)**	**$ 34,564,036**	**$ 17,132,512**	**$ 11,996,215**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 790,277**	**$ 553,353**
	SCHEDULE 24 (FOR RETAIL)			**$ 111,701**	**$ 78,213**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 16,230,534**	**$ 11,364,648**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	January - December 2024 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (190,013,234)	$ 286,933,670	$ 96,920,436	$ 69,203,327
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 43,981,920	$ -	$ 43,981,920	$ 31,235,233
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 25,511	$ -	$ 25,511	$ 17,922
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (87,360,230)	$ -	$ (87,360,230)	$ (62,394,570)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 2,717,025	$ -	$ 2,717,025	$ 1,942,752
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (26,225)	$ -	$ (26,225)	$ (18,425)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (4,674,633)	$ 16,525,321	$ 11,850,688	$ 8,419,415
13 c	Real-Time Asset Energy Amount - Loss Component	$ 601,194	$ -	$ 601,194	$ 429,863
14	Real-Time Distribution of Losses Amount	$ (10,904,038)	$ -	$ (10,904,038)	$ (7,752,893)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (242,014)	$ -	$ (242,014)	$ (171,649)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 578,253	$ -	$ 578,253	$ 420,577
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 11,604	$ -	$ 11,604	$ 8,343
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 168,354,879	$ -	$ 168,354,879	$ 119,694,379
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 322,233	$ -	$ 322,233	$ 229,141
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 9,153,883	$ -	$ 9,153,883	$ 6,587,343
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (323,377)	$ -	$ (323,377)	$ (229,948)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 1,929,019	$ -	$ 1,929,019	$ 1,378,329
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 33,823	$ -	$ 33,823	$ 24,444
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (30,612,495)	$ -	$ (30,612,495)	$ (21,737,375)
30	Financial Transmission Rights Monthly Allocation Amount	$ (1,235,376)	$ -	$ (1,235,376)	$ (857,650)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (672,102)	$ -	$ (672,102)	$ (471,885)
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (1,768,872)	$ -	$ (1,768,872)	$ (1,256,108)
37	Financial Transmission Guarantee Uplift Amount	$ 1,856,949	$ -	$ 1,856,949	$ 1,318,882
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 12,748,785	$ -	$ 12,748,785	$ 9,075,839
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 828,290	$ -	$ 828,290	$ 589,086
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (1,272,171)	$ 602,715	$ (669,456)	$ (476,183)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 947,523	$ -	$ 947,523	$ 672,141
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (1,607,202)	$ 750,920	$ (856,282)	$ (610,575)
43	Real Time Price Volatility Make Whole Payment	$ (1,907,477)	$ 544,141	$ (1,363,336)	$ (968,577)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 8,225,660	$ (1,218,954)	$ 7,006,706	$ 4,989,260
19	Real-Time Market Administration Amount	$ 832,935	$ (84,655)	$ 748,281	$ 532,656
29	Financial Transmission Rights Market Administration Amount	$ 205,900	$ -	$ 205,900	$ 146,940
33	Day-Ahead Schedule 24 Allocation Amount	$ 1,257,832	$ (186,551)	$ 1,071,281	$ 762,768
34	Real -Time Schedule 24 Allocation Amount	$ 127,367	$ (12,782)	$ 114,585	$ 81,554
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (2,206,058)	$ -	$ (2,206,058)	$ (1,553,432)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 67,386,473	$ -	$ 67,386,473	$ 47,938,844
40	Auction Revenue Rights - Monthly ARR Revenue	$ (67,549,338)	$ -	$ (67,549,338)	$ (48,054,506)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (13,896,006)	$ -	$ (13,896,006)	$ (9,901,667)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 1,280,428	$ -	$ 1,280,428	$ 910,944
	TOTAL MISO CHARGES	**$ (92,863,362)**	**$ 303,853,826**	**$ 210,990,464**	**$ 150,154,537**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 7,960,887**	**$ 5,668,856**
	SCHEDULE 24 (FOR RETAIL)			**$ 1,185,866**	**$ 844,322**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 201,843,711**	**$ 143,641,359**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	January 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
	Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(717,845)	$ (617,529)	228,487	$ 39,220,330	(946,332)	$ (39,837,859)	-	$ -
5a	Day Ahead Non Asset Energy	(165,051)	$ (9,857,257)	(165,051)	$ (9,857,257)	-	$ -	17,600	$ 976,187
13a	Real Time Asset Energy	23,389	$ 559,817	62,128	$ 2,373,517	(38,739)	$ (1,813,700)	-	$ -
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	(859,506)	$ (9,914,969)	125,565	$ 31,736,590	(985,071)	$ (41,651,559)	17,600	$ 976,187
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ 11,807	-	$ 11,807	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (1,877,644)	-	$ (1,877,644)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,865,837)	-	$ (1,865,837)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 534,014	-	$ 470,162	-	$ 63,851	-	$ 1,176
19	Real Time Market Administration (Schedule 17)	-	$ 61,661	-	$ 59,349	-	$ 2,312	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 14,076	-	$ 14,076	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 104,778	-	$ 92,408	-	$ 12,370	-	$ 232
34	Real -Time Schedule 24 Allocation Amount	-	$ 12,099	-	$ 11,581	-	$ 518	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 726,627	-	$ 647,576	-	$ 79,051	-	$ 1,408
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 39,043	-	$ 39,043	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (6,403,839)	-	$ (6,403,839)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (501,954)	-	$ (501,954)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ (672,102)	-	$ (672,102)	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ 62,538	-	$ 62,538	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 7,396	-	$ 7,396	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (7,468,919)	-	$ (7,468,919)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 121,773	-	$ 121,773	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (390,394)	-	$ (183,878)	-	$ (206,515)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 455,656	-	$ 455,656	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (499,147)	-	$ (202,979)	-	$ (296,167)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (120,998)	-	$ (94,666)	-	$ (26,332)	-	$ -
	SUBTOTAL	-	$ (433,109)	-	$ 95,905	-	$ (529,014)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 207,731	-	$ 207,731	-	$ -	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ (802)	-	$ (802)	-	$ -	-	$ (5)
23	Real Time Revenue Neutrality Uplift Amount	-	$ 1,779,997	-	$ 1,779,997	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,986,926	-	$ 1,986,926	-	$ -	-	$ (5)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 5,449,448	-	$ 5,449,448	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (5,468,626)	-	$ (5,468,626)	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (1,256,028)	-	$ (1,256,028)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 85,853	-	$ 85,853	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,189,354)	-	$ (1,189,354)	-	$ -	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (39,043)	-	$ (39,043)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (11,807)	-	$ (11,807)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (50,850)	-	$ (50,850)	-	$ -	-	$ -
	MISO Day 2 Charges	(859,506)	$ (18,209,486)	125,565	$ 23,892,037	(985,071)	$ (42,101,523)	17,600	$ 977,590
x	Net Congestion Amount	-	$ 15,751,198	-	$ 15,751,198	-	$ -	-	$ -
y	Net Loss Amount	-	$ 8,651,939	-	$ 8,651,939	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (24,403,137)	-	$ (24,403,137)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(859,506)**	**$ (18,209,486)**	**125,565**	**$ 23,892,037**	**(985,071)**	**$ (42,101,523)**	**17,600**	**$ 977,590**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	February 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(698,651)	$ 4,982,951	144,340	$ 17,688,806	(842,991)	$ (12,705,855)	-	$ -
5a	Day Ahead Non Asset Energy	(153,147)	$ (3,570,871)	(153,147)	$ (3,570,871)	-	$ -	16,800	$ 433,456
13a	Real Time Asset Energy	(85,691)	$ (1,446,929)	(1,215)	$ (485,267)	(84,476)	$ (961,663)	-	$ -
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	(937,489)	$ (34,849)	(10,022)	$ 13,632,668	(927,467)	$ (13,667,517)	16,800	$ 433,456
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ 5,394	-	$ 5,394	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (444,130)	-	$ (444,130)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (438,736)	-	$ (438,736)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 775,220	-	$ 681,958	-	$ 93,263	-	$ 1,861
19	Real Time Market Administration (Schedule 17)	-	$ 90,313	-	$ 81,003	-	$ 9,309	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 22,577	-	$ 22,577	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 91,655	-	$ 80,617	-	$ 11,038	-	$ 222
34	Real -Time Schedule 24 Allocation Amount	-	$ 10,520	-	$ 9,410	-	$ 1,110	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 990,286	-	$ 875,565	-	$ 114,721	-	$ 2,083
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 29,683	-	$ 29,683	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (1,253,003)	-	$ (1,253,003)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ 367,019	-	$ 367,019	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ 0	-	$ 0	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ 227,045	-	$ 227,045	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ (250,280)	-	$ (250,280)	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (879,536)	-	$ (879,536)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 68,877	-	$ 68,877	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ 3,038	-	$ (5,564)	-	$ 8,602	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ (89,633)	-	$ (89,633)	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (573)	-	$ 909	-	$ (1,482)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (420,308)	-	$ (331,137)	-	$ (89,172)	-	$ -
	SUBTOTAL	-	$ (438,600)	-	$ (356,548)	-	$ (82,052)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ (3,771,681)	-	$ (3,771,681)	-	$ -	-	$ 314
21	Real Time Net Inadvertent Distribution	-	$ 57,996	-	$ 57,996	-	$ -	-	$ 118
23	Real Time Revenue Neutrality Uplift Amount	-	$ 409,305	-	$ 409,305	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (3,304,380)	-	$ (3,304,380)	-	$ -	-	$ 432
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 5,449,448	-	$ 5,449,448	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (5,468,626)	-	$ (5,468,626)	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (1,256,028)	-	$ (1,256,028)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 85,853	-	$ 85,853	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,189,354)	-	$ (1,189,354)	-	$ -	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (29,683)	-	$ (29,683)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (5,394)	-	$ (5,394)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (35,077)	-	$ (35,077)	-	$ -	-	$ -
	MISO Day 2 Charges	(937,489)	$ (5,330,246)	(10,022)	$ 8,304,603	(927,467)	$ (13,634,848)	16,800	$ 435,971
x	Net Congestion Amount	-	$ 10,310,672	-	$ 10,310,672	-	$ -	-	$ -
y	Net Loss Amount	-	$ 3,045,755	-	$ 3,045,755	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (13,356,428)	-	$ (13,356,428)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(937,489)**	**$ (5,330,246)**	**(10,022)**	**$ 8,304,603**	**(927,467)**	**$ (13,634,848)**	**16,800**	**$ 435,971**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Northern States Power Company
Electric Operations - State of Minnesota
MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

Docket No. E002/AA-23-153
True-Up Report
Part B, Attachment 3

	March 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(1,097,391)	$ 6,018,002	21,548	$ 20,456,534	(1,118,939)	$ (14,438,532)	-	$ -
5a	Day Ahead Non Asset Energy	(164,569)	$ (2,844,519)	(164,569)	$ (2,844,519)	-	$ -	-	$ -
13a	Real Time Asset Energy	(30,009)	$ (467,132)	63,422	$ 604,157	(93,430)	$ (1,071,289)	-	$ -
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	(1,291,969)	$ 2,706,351	(79,600)	$ 18,216,172	(1,212,369)	$ (15,509,821)	-	$ -
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ 2,065	-	$ 2,065	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (1,130,969)	-	$ (1,130,969)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,128,903)	-	$ (1,128,903)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 547,667	-	$ 465,647	-	$ 82,020	-	$ 0
19	Real Time Market Administration (Schedule 17)	-	$ 50,580	-	$ 43,729	-	$ 6,851	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 17,146	-	$ 17,146	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 98,654	-	$ 83,882	-	$ 14,772	-	$ 0
34	Real -Time Schedule 24 Allocation Amount	-	$ 9,542	-	$ 8,311	-	$ 1,231	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 723,590	-	$ 618,716	-	$ 104,874	-	$ 0
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 25,319	-	$ 25,319	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (1,967,141)	-	$ (1,967,141)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (330,451)	-	$ (330,451)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (254,146)	-	$ (254,146)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 250,023	-	$ 250,023	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (2,276,396)	-	$ (2,276,396)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 61,809	-	$ 61,809	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (95,486)	-	$ (8,500)	-	$ (86,986)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 31,564	-	$ 31,564	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (33,000)	-	$ (9,946)	-	$ (23,054)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (92,518)	-	$ (43,052)	-	$ (49,466)	-	$ -
	SUBTOTAL	-	$ (127,631)	-	$ 31,875	-	$ (159,506)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 170,634	-	$ 170,634	-	$ -	-	$ (36)
21	Real Time Net Inadvertent Distribution	-	$ (420,130)	-	$ (420,130)	-	$ -	-	$ (64)
23	Real Time Revenue Neutrality Uplift Amount	-	$ 1,050,618	-	$ 1,050,618	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 801,122	-	$ 801,122	-	$ -	-	$ (101)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 4,814,922	-	$ 4,814,922	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (4,838,171)	-	$ (4,838,171)	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (1,016,112)	-	$ (1,016,112)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 122,929	-	$ 122,929	-	$ -	-	$ -
	SUBTOTAL	-	$ (916,431)	-	$ (916,431)	-	$ -	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (24,807)	-	$ (24,807)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (2,352)	-	$ (2,352)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (27,158)	-	$ (27,158)	-	$ -	-	$ -
	MISO Day 2 Charges	(1,291,969)	$ (245,456)	(79,600)	$ 15,318,996	(1,212,369)	$ (15,564,452)	-	$ (100)
x	Net Congestion Amount	-	$ 16,950,981	-	$ 16,950,981	-	$ -	-	$ -
y	Net Loss Amount	-	$ 3,069,654	-	$ 3,069,654	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (20,020,636)	-	$ (20,020,636)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,291,969)**	**$ (245,456)**	**(79,600)**	**$ 15,318,996**	**(1,212,369)**	**$ (15,564,452)**	**-**	**$ (100)**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	April 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(1,082,868)	$ 25,529,953	102,961	$ 30,960,113	(1,185,829)	$ (5,430,160)	-	$ -
5a	Day Ahead Non Asset Energy	(172,742)	$ (2,714,158)	(172,742)	$ (2,714,158)	-	$ -	-	$ -
13a	Real Time Asset Energy	(24,576)	$ (192,461)	112,807	$ 1,328,839	(137,383)	$ (1,521,299)	-	$ -
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	(1,280,187)	$ 22,623,334	43,025	$ 29,574,794	(1,323,212)	$ (6,951,459)	-	$ -
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ 837	-	$ 837	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (664,137)	-	$ (664,137)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (663,300)	-	$ (663,300)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 732,365	-	$ 611,398	-	$ 120,967	-	$ -
19	Real Time Market Administration (Schedule 17)	-	$ 75,966	-	$ 62,234	-	$ 13,732	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 16,523	-	$ 16,523	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 99,104	-	$ 82,446	-	$ 16,659	-	$ -
34	Real -Time Schedule 24 Allocation Amount	-	$ 10,267	-	$ 8,358	-	$ 1,909	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 934,225	-	$ 780,959	-	$ 153,266	-	$ -
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 43,681	-	$ 43,681	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (9,478,401)	-	$ (9,478,401)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (1,184,374)	-	$ (1,184,374)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (1,480,239)	-	$ (1,480,239)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 1,460,939	-	$ 1,460,939	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (10,638,394)	-	$ (10,638,394)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 65,228	-	$ 65,228	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (66,275)	-	$ (5,623)	-	$ (60,652)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 29,988	-	$ 29,988	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (52,524)	-	$ (16,828)	-	$ (35,697)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (395,573)	-	$ (281,766)	-	$ (113,806)	-	$ -
	SUBTOTAL	-	$ (419,156)	-	$ (209,001)	-	$ (210,154)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 169,638	-	$ 169,638	-	$ -	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ 194,526	-	$ 194,526	-	$ -	-	$ 14
23	Real Time Revenue Neutrality Uplift Amount	-	$ 740,008	-	$ 740,008	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,104,172	-	$ 1,104,172	-	$ -	-	$ 14
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 4,814,922	-	$ 4,814,922	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (4,838,171)	-	$ (4,838,171)	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (1,016,414)	-	$ (1,016,414)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 122,731	-	$ 122,731	-	$ -	-	$ -
	SUBTOTAL	-	$ (916,932)	-	$ (916,932)	-	$ -	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (43,681)	-	$ (43,681)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (837)	-	$ (837)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (44,519)	-	$ (44,519)	-	$ -	-	$ -
	MISO Day 2 Charges	(1,280,187)	$ 11,979,433	43,025	$ 18,987,780	(1,323,212)	$ (7,008,347)	-	$ 14
x	Net Congestion Amount	-	$ 25,415,497	-	$ 25,415,497	-	$ -	-	$ -
y	Net Loss Amount	-	$ 2,824,631	-	$ 2,824,631	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (28,240,128)	-	$ (28,240,128)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,280,187)**	**$ 11,979,433**	**43,025**	**$ 18,987,780**	**(1,323,212)**	**$ (7,008,347)**	**-**	**$ 14**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	May 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(1,039,645)	$ (1,795,719)	184,105	$ 17,074,023	(1,223,751)	$ (18,869,743)	-	$ -
5a	Day Ahead Non Asset Energy	(238,186)	$ (6,059,219)	(238,186)	$ (6,059,219)	-	$ -	-	$ -
13a	Real Time Asset Energy	21,146	$ 899,649	129,770	$ 2,667,862	(108,624)	$ (1,768,214)	-	$ -
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	(1,256,686)	$ (6,955,289)	75,689	$ 13,682,667	(1,332,375)	$ (20,637,956)	-	$ -
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ 1,480	-	$ 1,480	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (230,895)	-	$ (230,895)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (229,415)	-	$ (229,415)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 672,568	-	$ 560,019	-	$ 112,549	-	$ -
19	Real Time Market Administration (Schedule 17)	-	$ 74,750	-	$ 64,794	-	$ 9,956	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 16,608	-	$ 16,608	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 97,855	-	$ 81,456	-	$ 16,399	-	$ -
34	Real -Time Schedule 24 Allocation Amount	-	$ 10,879	-	$ 9,424	-	$ 1,455	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 872,661	-	$ 732,302	-	$ 140,359	-	$ -
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 14,044	-	$ 14,044	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ 392,791	-	$ 392,791	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ 770,859	-	$ 770,859	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (280,222)	-	$ (280,222)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 291,287	-	$ 291,287	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,188,760	-	$ 1,188,760	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 50,714	-	$ 50,714	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (113,348)	-	$ (66,617)	-	$ (46,731)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 36,831	-	$ 36,831	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ 1,118	-	$ 1,380	-	$ (262)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (217,487)	-	$ (121,565)	-	$ (95,922)	-	$ -
	SUBTOTAL	-	$ (242,173)	-	$ (99,258)	-	$ (142,914)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 175,834	-	$ 175,834	-	$ -	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ 220,404	-	$ 220,404	-	$ -	-	$ 3
23	Real Time Revenue Neutrality Uplift Amount	-	$ 451,059	-	$ 451,059	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 847,297	-	$ 847,297	-	$ -	-	$ 3
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 4,814,922	-	$ 4,814,922	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (4,838,171)	-	$ (4,838,171)	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (6,098,486)	-	$ (6,098,486)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 736,335	-	$ 736,335	-	$ -	-	$ -
	SUBTOTAL	-	$ (5,385,399)	-	$ (5,385,399)	-	$ -	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (14,044)	-	$ (14,044)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (1,480)	-	$ (1,480)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (15,524)	-	$ (15,524)	-	$ -	-	$ -
	MISO Day 2 Charges	(1,256,686)	$ (9,919,083)	75,689	$ 10,721,428	(1,332,375)	$ (20,640,511)	-	$ 3
x	Net Congestion Amount	-	$ 8,684,344	-	$ 8,684,344	-	$ -	-	$ -
y	Net Loss Amount	-	$ 2,656,518	-	$ 2,656,518	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (11,340,862)	-	$ (11,340,862)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,256,686)**	**$ (9,919,083)**	**75,689**	**$ 10,721,428**	**(1,332,375)**	**$ (20,640,511)**	**-**	**$ 3**

x No longer reported in 1b, 5b, 13b, 22b

y No longer reported in 1c, 5c, 13c, 22c

z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	June 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(1,066,408)	$ (6,481,397)	219,478	$ 16,909,077	(1,285,886)	$ (23,390,473)	-	$ -
5a	Day Ahead Non Asset Energy	(257,341)	$ (6,687,665)	(257,341)	$ (6,687,665)	-	$ -	6,400	$ 173,852
13a	Real Time Asset Energy	(23,255)	$ (4,153)	69,646	$ 1,415,568	(92,900)	$ (1,419,722)	-	$ -
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	(1,347,004)	$ (13,173,215)	31,782	$ 11,636,980	(1,378,786)	$ (24,810,195)	6,400	$ 173,852
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (2,234)	-	$ (2,234)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (1,232,637)	-	$ (1,232,637)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,234,871)	-	$ (1,234,871)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 634,612	-	$ 533,281	-	$ 101,330	-	$ 755
19	Real Time Market Administration (Schedule 17)	-	$ 64,581	-	$ 57,419	-	$ 7,161	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 17,865	-	$ 17,865	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 104,863	-	$ 88,145	-	$ 16,718	-	$ 125
34	Real -Time Schedule 24 Allocation Amount	-	$ 10,688	-	$ 9,481	-	$ 1,207	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 832,608	-	$ 706,191	-	$ 126,417	-	$ 880
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ (16)	-	$ (16)	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (486,341)	-	$ (486,341)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ 382,449	-	$ 382,449	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ 43,128	-	$ 43,128	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 10,650	-	$ 10,650	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (50,130)	-	$ (50,130)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 42,191	-	$ 42,191	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (109,716)	-	$ (51,156)	-	$ (58,560)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 31,815	-	$ 31,815	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (41,559)	-	$ (29,893)	-	$ (11,666)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (42,799)	-	$ (23,649)	-	$ (19,150)	-	$ -
	SUBTOTAL	-	$ (120,068)	-	$ (30,692)	-	$ (89,376)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 172,904	-	$ 172,904	-	$ -	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ (128,324)	-	$ (128,324)	-	$ -	-	$ (156)
23	Real Time Revenue Neutrality Uplift Amount	-	$ 1,064,074	-	$ 1,064,074	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,108,653	-	$ 1,108,653	-	$ -	-	$ (156)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 4,224,471	-	$ 4,224,471	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (4,227,298)	-	$ (4,227,298)	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (4,353,376)	-	$ (4,353,376)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ (497,602)	-	$ (497,602)	-	$ -	-	$ -
	SUBTOTAL	-	$ (4,853,805)	-	$ (4,853,805)	-	$ -	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ 16	-	$ 16	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 2,234	-	$ 2,234	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 2,250	-	$ 2,250	-	$ -	-	$ -
	MISO Day 2 Charges	(1,347,004)	$ (17,488,579)	31,782	$ 7,284,575	(1,378,786)	$ (24,773,154)	6,400	$ 174,576
x	Net Congestion Amount	-	$ 7,938,485	-	$ 7,938,485	-	$ -	-	$ -
y	Net Loss Amount	-	$ 3,212,276	-	$ 3,212,276	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (11,150,761)	-	$ (11,150,761)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,347,004)**	**$ (17,488,579)**	**31,782**	**$ 7,284,575**	**(1,378,786)**	**$ (24,773,154)**	**6,400**	**$ 174,576**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	July 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
	Posting Account Description	MWh	Net Cost	MWh	Revenue	MWh	Revenue	MWh	Revenue
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(1,259,973)	$ (24,437,327)	315,347	$ 21,678,872	(1,575,320)	$ (46,116,199)	-	$ -
5a	Day Ahead Non Asset Energy	(282,263)	$ (11,692,812)	(282,263)	$ (11,692,812)	-	$ -	8,800	$ 366,529
13a	Real Time Asset Energy	(55,636)	$ 981	4,739	$ 1,510,250	(60,375)	$ (1,509,270)	-	$ -
22a	Real Time Non Asset Energy	1,119	$ 2,788,845	1,119	$ 2,788,845	-	$ -	-	$ -
	SUBTOTAL	(1,596,752)	$ (33,340,313)	38,943	$ 14,285,155	(1,635,695)	$ (47,625,469)	8,800	$ 366,529
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ 1,437	-	$ 1,437	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (775,314)	-	$ (775,314)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (773,878)	-	$ (773,878)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 744,087	-	$ 618,817	-	$ 125,269	-	$ 700
19	Real Time Market Administration (Schedule 17)	-	$ 58,824	-	$ 53,992	-	$ 4,831	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 29,086	-	$ 29,086	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 111,945	-	$ 92,980	-	$ 18,966	-	$ 106
34	Real -Time Schedule 24 Allocation Amount	-	$ 8,842	-	$ 8,120	-	$ 722	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 952,784	-	$ 802,995	-	$ 149,789	-	$ 806
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 32,272	-	$ 32,272	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (873,678)	-	$ (873,678)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (36,779)	-	$ (36,779)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (4,187)	-	$ (4,187)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 4,014	-	$ 4,014	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (878,359)	-	$ (878,359)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 74,320	-	$ 74,320	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ 3,668	-	$ 6,688	-	$ (3,020)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 108,665	-	$ 108,665	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (225,583)	-	$ (28,630)	-	$ (196,953)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (84,253)	-	$ (68,123)	-	$ (16,130)	-	$ -
	SUBTOTAL	-	$ (123,184)	-	$ 92,919	-	$ (216,103)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 188,455	-	$ 188,455	-	$ -	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ 8,725	-	$ 8,725	-	$ -	-	$ 85
23	Real Time Revenue Neutrality Uplift Amount	-	$ 1,236,876	-	$ 1,236,876	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,434,056	-	$ 1,434,056	-	$ -	-	$ 85
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 4,224,471	-	$ 4,224,471	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (4,227,298)	-	$ (4,227,298)	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (1,179,431)	-	$ (1,179,431)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 14,501	-	$ 14,501	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,167,757)	-	$ (1,167,757)	-	$ -	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (32,272)	-	$ (32,272)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (1,437)	-	$ (1,437)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (33,709)	-	$ (33,709)	-	$ -	-	$ -
	MISO Day 2 Charges	(1,596,752)	$ (33,930,359)	38,943	$ 13,761,424	(1,635,695)	$ (47,691,783)	8,800	$ 367,419
x	Net Congestion Amount	-	$ 5,231,669	-	$ 5,231,669	-	$ -	-	$ -
y	Net Loss Amount	-	$ 3,555,982	-	$ 3,555,982	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (8,787,651)	-	$ (8,787,651)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,596,752)**	**$ (33,930,359)**	**38,943**	**$ 13,761,424**	**(1,635,695)**	**$ (47,691,783)**	**8,800**	**$ 367,419**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	August 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(1,291,948)	$ (13,014,452)	349,197	$ 23,803,988	(1,641,146)	$ (36,818,440)	-	$ -
5a	Day Ahead Non Asset Energy	(278,621)	$ (9,170,038)	(278,621)	$ (9,170,038)	-	$ -	8,800	$ 309,118
13a	Real Time Asset Energy	(54,484)	$ (994,689)	21,562	$ 591,771	(76,045)	$ (1,586,460)	-	$ -
22a	Real Time Non Asset Energy	(2,100)	$ (2,654,501)	(2,100)	$ (2,654,501)	-	$ -	-	$ -
	SUBTOTAL	(1,627,153)	$ (25,833,680)	90,038	$ 12,571,220	(1,717,191)	$ (38,404,900)	8,800	$ 309,118
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (644)	-	$ (644)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (1,394,179)	-	$ (1,394,179)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,394,823)	-	$ (1,394,823)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 736,971	-	$ 602,091	-	$ 134,880	-	$ 708
19	Real Time Market Administration (Schedule 17)	-	$ 64,980	-	$ 58,849	-	$ 6,131	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 23,341	-	$ 23,341	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 111,848	-	$ 91,603	-	$ 20,245	-	$ 110
34	Real -Time Schedule 24 Allocation Amount	-	$ 9,864	-	$ 8,935	-	$ 929	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 947,004	-	$ 784,820	-	$ 162,184	-	$ 817
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 17,932	-	$ 17,932	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (607,257)	-	$ (607,257)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (91,243)	-	$ (91,243)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (95,458)	-	$ (95,458)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 88,116	-	$ 88,116	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (687,911)	-	$ (687,911)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 71,704	-	$ 71,704	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (76,318)	-	$ (57,975)	-	$ (18,343)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 144,420	-	$ 144,420	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (12,760)	-	$ 2,674	-	$ (15,434)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (229,929)	-	$ (198,614)	-	$ (31,315)	-	$ -
	SUBTOTAL	-	$ (102,883)	-	$ (37,791)	-	$ (65,092)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 173,504	-	$ 173,504	-	$ -	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ (75,399)	-	$ (75,399)	-	$ -	-	$ (80)
23	Real Time Revenue Neutrality Uplift Amount	-	$ 931,449	-	$ 931,449	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,029,555	-	$ 1,029,555	-	$ -	-	$ (80)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 4,224,471	-	$ 4,224,471	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (4,227,298)	-	$ (4,227,298)	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ -	-	$ -	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (2,827)	-	$ (2,827)	-	$ -	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (17,932)	-	$ (17,932)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 644	-	$ 644	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (17,288)	-	$ (17,288)	-	$ -	-	$ -
	MISO Day 2 Charges	(1,627,153)	$ (26,062,854)	90,038	$ 12,244,954	(1,717,191)	$ (38,307,808)	8,800	$ 309,855
x	Net Congestion Amount	-	$ 9,527,921	-	$ 9,527,921	-	$ -	-	$ -
y	Net Loss Amount	-	$ 3,565,327	-	$ 3,565,327	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (13,093,248)	-	$ (13,093,248)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,627,153)**	**$ (26,062,854)**	**90,038**	**$ 12,244,954**	**(1,717,191)**	**$ (38,307,808)**	**8,800**	**$ 309,855**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Docket No. E002/AA-23-153
True-Up Report
Part B, Attachment 3

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	September 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(1,026,969)	$ 17,707,920	141,482	$ 42,253,007	(1,168,451)	$ (24,545,087)	-	$ -
5a	Day Ahead Non Asset Energy	(267,758)	$ (5,994,437)	(267,758)	$ (5,994,437)	-	$ -	8,000	$ 294,644
13a	Real Time Asset Energy	(28,734)	$ (318,330)	4,352	$ 390,751	(33,086)	$ (709,081)	-	$ -
22a	Real Time Non Asset Energy	1,477	$ 107,414	1,477	$ 107,414	-	$ -	-	$ -
	SUBTOTAL	(1,321,984)	$ 11,502,568	(120,447)	$ 36,756,736	(1,201,537)	$ (25,254,168)	8,000	$ 294,644
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (853)	-	$ (853)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (805,437)	-	$ (805,437)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (806,290)	-	$ (806,290)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 745,518	-	$ 637,443	-	$ 108,076	-	$ 739
19	Real Time Market Administration (Schedule 17)	-	$ 69,203	-	$ 66,189	-	$ 3,014	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 17,074	-	$ 17,074	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 117,712	-	$ 101,854	-	$ 15,858	-	$ 117
34	Real -Time Schedule 24 Allocation Amount	-	$ 10,921	-	$ 10,489	-	$ 432	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 960,429	-	$ 833,050	-	$ 127,379	-	$ 856
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 44,054	-	$ 44,054	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (7,682,234)	-	$ (7,682,234)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (282,571)	-	$ (282,571)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (154,263)	-	$ (154,263)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 149,508	-	$ 149,508	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (7,925,506)	-	$ (7,925,506)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 86,314	-	$ 86,314	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (131,488)	-	$ (96,590)	-	$ (34,898)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 70,807	-	$ 70,807	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (563,053)	-	$ (480,821)	-	$ (82,232)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (39,554)	-	$ (29,562)	-	$ (9,992)	-	$ -
	SUBTOTAL	-	$ (576,976)	-	$ (449,853)	-	$ (127,122)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 134,368	-	$ 134,368	-	$ -	-	$ (65)
21	Real Time Net Inadvertent Distribution	-	$ (78,126)	-	$ (78,126)	-	$ -	-	$ (41)
23	Real Time Revenue Neutrality Uplift Amount	-	$ 1,399,705	-	$ 1,399,705	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,455,946	-	$ 1,455,946	-	$ -	-	$ (106)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 7,426,682	-	$ 7,426,682	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (7,439,189)	-	$ (7,439,189)	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ 5,882,331	-	$ 5,882,331	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 100,943	-	$ 100,943	-	$ -	-	$ -
	SUBTOTAL	-	$ 5,970,767	-	$ 5,970,767	-	$ -	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (44,054)	-	$ (44,054)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 853	-	$ 853	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (43,202)	-	$ (43,202)	-	$ -	-	$ -
	MISO Day 2 Charges	(1,321,984)	$ 10,537,737	(120,447)	$ 35,791,648	(1,201,537)	$ (25,253,911)	8,000	$ 295,394
x	Net Congestion Amount	-	$ 33,461,079	-	$ 33,461,079	-	$ -	-	$ -
y	Net Loss Amount	-	$ 4,071,647	-	$ 4,071,647	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (37,532,725)	-	$ (37,532,725)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,321,984)**	**$ 10,537,737**	**(120,447)**	**$ 35,791,648**	**(1,201,537)**	**$ (25,253,911)**	**8,000**	**$ 295,394**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	October 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(561,251)	$ 21,312,079	451,816	$ 34,987,392	(1,013,067)	$ (13,675,313)	-	$ -
5a	Day Ahead Non Asset Energy	(289,717)	$ (7,627,394)	(289,717)	$ (7,627,394)	-	$ -	7,360	$ 251,245
13a	Real Time Asset Energy	(35,646)	$ (693,629)	14,139	$ 116,716	(49,786)	$ (810,345)	-	$ -
22a	Real Time Non Asset Energy	1	$ 192	1	$ 192	-	$ -	-	$ -
	SUBTOTAL	(886,614)	$ 12,991,249	176,238	$ 27,476,907	(1,062,852)	$ (14,485,658)	7,360	$ 251,245
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (590)	-	$ (590)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (775,165)	-	$ (775,165)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (775,755)	-	$ (775,755)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 657,536	-	$ 562,617	-	$ 94,919	-	$ 692
19	Real Time Market Administration (Schedule 17)	-	$ 69,217	-	$ 64,378	-	$ 4,839	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 14,525	-	$ 14,525	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 99,292	-	$ 84,629	-	$ 14,663	-	$ 104
34	Real -Time Schedule 24 Allocation Amount	-	$ 10,451	-	$ 9,711	-	$ 740	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 851,021	-	$ 735,860	-	$ 115,162	-	$ 796
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 38,818	-	$ 38,818	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (992,924)	-	$ (992,924)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (101,726)	-	$ (101,726)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ 202,004	-	$ 202,004	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ (189,775)	-	$ (189,775)	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,043,603)	-	$ (1,043,603)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 50,466	-	$ 50,466	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (87,639)	-	$ (67,675)	-	$ (19,964)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 14,929	-	$ 14,929	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ 28,234	-	$ 77,021	-	$ (48,787)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (34,184)	-	$ (6,714)	-	$ (27,470)	-	$ -
	SUBTOTAL	-	$ (28,194)	-	$ 68,026	-	$ (96,220)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 124,292	-	$ 124,292	-	$ -	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ (111,037)	-	$ (111,037)	-	$ -	-	$ (136)
23	Real Time Revenue Neutrality Uplift Amount	-	$ 1,693,229	-	$ 1,693,229	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,706,484	-	$ 1,706,484	-	$ -	-	$ (136)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 7,426,682	-	$ 7,426,682	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (7,439,189)	-	$ (7,439,189)	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (1,194,256)	-	$ (1,194,256)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 187,951	-	$ 187,951	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,018,812)	-	$ (1,018,812)	-	$ -	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (38,818)	-	$ (38,818)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 590	-	$ 590	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (38,229)	-	$ (38,229)	-	$ -	-	$ -
	MISO Day 2 Charges	(886,614)	$ 12,644,162	176,238	$ 27,110,879	(1,062,852)	$ (14,466,717)	7,360	$ 251,904
x	Net Congestion Amount	-	$ 18,169,397	-	$ 18,169,397	-	$ -	-	$ -
y	Net Loss Amount	-	$ 3,700,047	-	$ 3,700,047	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (21,869,444)	-	$ (21,869,444)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(886,614)**	**$ 12,644,162**	**176,238**	**$ 27,110,879**	**(1,062,852)**	**$ (14,466,717)**	**7,360**	**$ 251,904**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Docket No. E002/AA-23-153
True-Up Report
Part B, Attachment 3

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	November 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(783,500)	$ 3,553,900	106,566	$ 22,717,982	(890,066)	$ (19,164,082)	-	$ -
5a	Day Ahead Non Asset Energy	(156,584)	$ (3,699,537)	(156,584)	$ (3,699,537)	-	$ -	6,400	$ 199,238
13a	Real Time Asset Energy	(9,473)	$ 31,474	48,871	$ 718,624	(58,344)	$ (687,150)	-	$ -
22a	Real Time Non Asset Energy	(449)	$ (15,073)	(449)	$ (15,073)	-	$ -	-	$ -
	SUBTOTAL	(950,006)	$ (129,236)	(1,595)	$ 19,721,996	(948,410)	$ (19,851,232)	6,400	$ 199,238
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ 372	-	$ 372	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (515,596)	-	$ (515,596)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (515,224)	-	$ (515,224)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 632,602	-	$ 552,698	-	$ 79,903	-	$ 576
19	Real Time Market Administration (Schedule 17)	-	$ 66,577	-	$ 61,280	-	$ 5,297	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 12,439	-	$ 12,439	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 103,918	-	$ 90,278	-	$ 13,640	-	$ 96
34	Real -Time Schedule 24 Allocation Amount	-	$ 10,944	-	$ 10,048	-	$ 896	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 826,479	-	$ 726,743	-	$ 99,737	-	$ 672
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 7,698	-	$ 7,698	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ 315,309	-	$ 315,309	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (119,782)	-	$ (119,782)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (27,540)	-	$ (27,540)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 27,540	-	$ 27,540	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 203,225	-	$ 203,225	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 64,038	-	$ 64,038	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (197,250)	-	$ (126,395)	-	$ (70,855)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 18,574	-	$ 18,574	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (3,221)	-	$ (3,450)	-	$ 229	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (84,924)	-	$ (60,311)	-	$ (24,613)	-	$ -
	SUBTOTAL	-	$ (202,783)	-	$ (107,544)	-	$ (95,239)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 122,145	-	$ 122,145	-	$ -	-	$ 1
21	Real Time Net Inadvertent Distribution	-	$ (52,363)	-	$ (52,363)	-	$ -	-	$ (43)
23	Real Time Revenue Neutrality Uplift Amount	-	$ 1,369,617	-	$ 1,369,617	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,439,399	-	$ 1,439,399	-	$ -	-	$ (43)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 7,426,682	-	$ 7,426,682	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (7,439,189)	-	$ (7,439,189)	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (1,194,256)	-	$ (1,194,256)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 187,951	-	$ 187,951	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,018,812)	-	$ (1,018,812)	-	$ -	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (9,355)	-	$ (9,355)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (800)	-	$ (800)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (10,155)	-	$ (10,155)	-	$ -	-	$ -
	MISO Day 2 Charges	(950,006)	$ 592,894	(1,595)	$ 20,439,628	(948,410)	$ (19,846,734)	6,400	$ 199,868
x	Net Congestion Amount	-	$ 15,060,360	-	$ 15,060,360	-	$ -	-	$ -
y	Net Loss Amount	-	$ 3,597,543	-	$ 3,597,543	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (18,657,903)	-	$ (18,657,903)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(950,006)**	**$ 592,894**	**(1,595)**	**$ 20,439,628**	**(948,410)**	**$ (19,846,734)**	**6,400**	**$ 199,868**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	December 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(1,018,192)	$ (10,434,816)	11,641	$ 21,507,111	(1,029,834)	$ (31,941,927)	-	$ -
5a	Day Ahead Non Asset Energy	(158,700)	$ (5,571,417)	(158,700)	$ (5,571,417)	-	$ -	-	$ -
13a	Real Time Asset Energy	(2,493)	$ 480,984	109,069	$ 3,148,113	(111,562)	$ (2,667,129)	-	$ -
22a	Real Time Non Asset Energy	674	$ 17,405	674	$ 17,405	-	$ -	1	$ 22
	SUBTOTAL	(1,178,711)	$ (15,507,844)	(37,315)	$ 19,101,212	(1,141,396)	$ (34,609,056)	1	$ 22
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ 6,439	-	$ 6,439	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (1,057,933)	-	$ (1,057,933)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,051,495)	-	$ (1,051,495)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 812,500	-	$ 710,574	-	$ 101,926	-	$ -
19	Real Time Market Administration (Schedule 17)	-	$ 86,284	-	$ 75,064	-	$ 11,220	-	$ 0
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 4,640	-	$ 4,640	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 116,207	-	$ 100,984	-	$ 15,223	-	$ -
34	Real -Time Schedule 24 Allocation Amount	-	$ 12,349	-	$ 10,716	-	$ 1,633	-	$ 0
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,031,980	-	$ 901,978	-	$ 130,002	-	$ 0
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 29,704	-	$ 29,704	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (1,575,777)	-	$ (1,575,777)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (106,822)	-	$ (106,822)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (7,531)	-	$ (7,531)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 7,531	-	$ 7,531	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,652,895)	-	$ (1,652,895)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 70,858	-	$ 70,858	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (10,962)	-	$ (6,169)	-	$ (4,793)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 93,909	-	$ 93,909	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (205,133)	-	$ (165,719)	-	$ (39,414)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (144,951)	-	$ (104,176)	-	$ (40,775)	-	$ -
	SUBTOTAL	-	$ (196,281)	-	$ (111,298)	-	$ (84,982)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 305,517	-	$ 305,517	-	$ -	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ 142,516	-	$ 142,516	-	$ -	-	$ 18
23	Real Time Revenue Neutrality Uplift Amount	-	$ 622,847	-	$ 622,847	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,070,880	-	$ 1,070,880	-	$ -	-	$ 18
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 7,089,351	-	$ 7,089,351	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (7,098,113)	-	$ (7,098,113)	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (1,213,949)	-	$ (1,213,949)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 132,984	-	$ 132,984	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,089,728)	-	$ (1,089,728)	-	$ -	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (29,704)	-	$ (29,704)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (6,439)	-	$ (6,439)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (36,143)	-	$ (36,143)	-	$ -	-	$ -
	MISO Day 2 Charges	(1,178,711)	$ (17,431,524)	(37,315)	$ 17,132,512	(1,141,396)	$ (34,564,036)	1	$ 40
x	Net Congestion Amount	-	$ 12,970,001	-	$ 12,970,001	-	$ -	-	$ -
y	Net Loss Amount	-	$ 5,360,422	-	$ 5,360,422	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (18,330,422)	-	$ (18,330,422)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,178,711)**	**$ (17,431,524)**	**(37,315)**	**$ 17,132,512**	**(1,141,396)**	**$ (34,564,036)**	**1**	**$ 40**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Northern States Power Company
Electric Operations - State of Minnesota

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	January - December 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(11,644,641)	$ 22,323,565	2,276,969	$ 309,257,235	(13,921,610)	$ (286,933,670)	-	$ -
5a	Day Ahead Non Asset Energy	(2,584,679)	$ (75,489,323)	(2,584,679)	$ (75,489,323)	-	$ -	80,160	$ 3,004,267
13a	Real Time Asset Energy	(305,461)	$ (2,144,419)	639,290	$ 14,380,901	(944,751)	$ (16,525,321)	-	$ -
22a	Real Time Non Asset Energy	722	$ 244,283	722	$ 244,283	-	$ -	1	$ 22
	SUBTOTAL	(14,534,059)	$ (55,065,894)	332,302	$ 248,393,096	(14,866,361)	$ (303,458,991)	80,161	$ 3,004,289
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ 25,511	-	$ 25,511	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (10,904,038)	-	$ (10,904,038)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (10,878,526)	-	$ (10,878,526)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 8,225,660	-	$ 7,006,706	-	$ 1,218,954	-	$ 7,208
19	Real Time Market Administration (Schedule 17)	-	$ 832,935	-	$ 748,281	-	$ 84,655	-	$ 0
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 205,900	-	$ 205,900	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 1,257,832	-	$ 1,071,281	-	$ 186,551	-	$ 1,111
34	Real -Time Schedule 24 Allocation Amount	-	$ 127,367	-	$ 114,585	-	$ 12,782	-	$ 0
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 10,649,694	-	$ 9,146,753	-	$ 1,502,941	-	$ 8,319
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 322,233	-	$ 322,233	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (30,612,495)	-	$ (30,612,495)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (1,235,376)	-	$ (1,235,376)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ (672,102)	-	$ (672,102)	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (1,768,872)	-	$ (1,768,872)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 1,856,949	-	$ 1,856,949	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (32,109,663)	-	$ (32,109,663)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 828,290	-	$ 828,290	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (1,272,171)	-	$ (669,456)	-	$ (602,715)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 947,523	-	$ 947,523	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (1,607,202)	-	$ (856,282)	-	$ (750,920)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (1,907,477)	-	$ (1,363,336)	-	$ (544,141)	-	$ -
	SUBTOTAL	-	$ (3,011,038)	-	$ (1,113,261)	-	$ (1,897,776)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ (1,826,660)	-	$ (1,826,660)	-	$ -	-	$ 213
21	Real Time Net Inadvertent Distribution	-	$ (242,014)	-	$ (242,014)	-	$ -	-	$ (287)
23	Real Time Revenue Neutrality Uplift Amount	-	$ 12,748,785	-	$ 12,748,785	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 10,680,111	-	$ 10,680,111	-	$ -	-	$ (74)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 67,386,473	-	$ 67,386,473	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (67,549,338)	-	$ (67,549,338)	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (13,896,006)	-	$ (13,896,006)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 1,280,428	-	$ 1,280,428	-	$ -	-	$ -
	SUBTOTAL	-	$ (12,778,442)	-	$ (12,778,442)	-	$ -	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (323,377)	-	$ (323,377)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (26,225)	-	$ (26,225)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (349,603)	-	$ (349,603)	-	$ -	-	$ -
	MISO Day 2 Charges	(14,534,059)	$ (92,863,362)	332,302	$ 210,990,464	(14,866,361)	$ (303,853,826)	80,161	$ 3,012,534
x	Net Congestion Amount	-	$ 179,471,604	-	$ 179,471,604	-	$ -	-	$ -
y	Net Loss Amount	-	$ 47,311,743	-	$ 47,311,743	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (226,783,347)	-	$ (226,783,347)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(14,534,059)**	**$ (92,863,362)**	**332,302**	**$ 210,990,464**	**(14,866,361)**	**$ (303,853,826)**	**80,161**	**$ 3,012,534**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System		Intersystem		Retail		Minnesota Retail	
	January 2024	**Actual**							
Procurement Charges									
1	Day-Ahead Regulation Amount	$	(121,697)	$	-	$	(121,697)	$	(85,444)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$	(240,616)	$	-	$	(240,616)	$	(168,937)
3	Day-Ahead Supplemental Reserve	$	(1,057,723)	$	-	$	(1,057,723)	$	(742,631)
4	Real-Time Regulation Amount (See Note 1)	$	(118,618)	$	1,227,964	$	1,109,345	$	778,875
5	Real-Time Spinning Reserve Amount	$	(8,827)	$	196,433	$	187,606	$	131,719
6	Real-Time Supplemental Reserve Amount.	$	45,929	$	21,248	$	67,177	$	47,165
Resource Energy Charges									
7a	Real Time Excessive Energy Amount	$	(22,938)	$	-	$	(22,938)	$	(16,105)
7b	Real Time Excessive Energy Congestion	$	-	$	-	$	-	$	-
7c	Real Time Excessive Energy Loss	$	-	$	-	$	-	$	-
8a	Real Time Non Excessive Energy Amount	$	10,853,149	$	-	$	10,853,149	$	7,620,033
8b	Real Time Non Excessive Energy Congestion	$	(274,754)	$	-	$	(274,754)	$	(192,906)
8c	Real Time Non Excessive Energy Loss	$	22,000	$	-	$	22,000	$	15,446
9	Real Time Net Regulation Adjustment Amount	$	(52,218)	$	2,622	$	(49,597)	$	(34,822)
Cost Distribution Charges									
10	Real Time Regulation Reserve Cost Distribution Amount	$	67,130	$	-	$	67,130	$	47,132
11	Real Time Spinning Reserve Cost Distribution	$	96,854	$	-	$	96,854	$	68,002
12	Real Time Supplemental Reserve Cost Distribution	$	650,347	$	-	$	650,347	$	456,611
Penalty Charges									
13	Real Time Excessive/Deficient Energy Deployment	$	67,586	$	(15,838)	$	51,748	$	36,332
14	Real Time Contingency Reserve Deployment Failure	$	1,025	$	-	$	1,025	$	720
	TOTAL MISO ASM CHARGES	**$**	**9,906,628**	**$**	**1,432,428**	**$**	**11,339,056**	**$**	**7,961,190**

Ramp Capability Amounts (Included in Regulation Amounts)									
1	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$	(9,913)	$	-	$	(9,913)	$	(6,960)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$	(4,219)	$	-	$	(4,219)	$	(2,962)
	Total	$	(14,132)	$	-	$	(14,132)	$	(9,922)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$**	**9,920,760**	**$**	**1,432,428**	**$**	**11,353,188**	**$**	**7,971,112**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	February 2024 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (71,355)	$ -	$ (71,355)	$ (50,494)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (120,580)	$ -	$ (120,580)	$ (85,328)
3	Day-Ahead Supplemental Reserve	$ (37,721)	$ -	$ (37,721)	$ (26,693)
4	Real-Time Regulation Amount (See Note 1)	$ (63,921)	$ (186,545)	$ (250,466)	$ (177,242)
5	Real-Time Spinning Reserve Amount	$ (31,898)	$ 83,420	$ 51,522	$ 36,459
6	Real-Time Supplemental Reserve Amount.	$ 15,426	$ 10,444	$ 25,870	$ 18,307
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 5,080	$ -	$ 5,080	$ 3,595
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,506,779	$ -	$ 3,506,779	$ 2,481,561
8b	Real Time Non Excessive Energy Congestion	$ (94,673)	$ -	$ (94,673)	$ (66,995)
8c	Real Time Non Excessive Energy Loss	$ 5,964	$ -	$ 5,964	$ 4,221
9	Real Time Net Regulation Adjustment Amount	$ 11,294	$ 1,210	$ 12,505	$ 8,849
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 108,499	$ -	$ 108,499	$ 76,779
11	Real Time Spinning Reserve Cost Distribution	$ 77,963	$ -	$ 77,963	$ 55,170
12	Real Time Supplemental Reserve Cost Distribution	$ (91,462)	$ -	$ (91,462)	$ (64,723)
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 12,536	$ (6,341)	$ 6,194	$ 4,383
14	Real Time Contingency Reserve Deployment Failure	$ 69	$ -	$ 69	$ 49
	TOTAL MISO ASM CHARGES	**$ 3,232,001**	**$ (97,812)**	**$ 3,134,189**	**$ 2,217,899**

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
1	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (5,481)	$ -	$ (5,481)	$ (3,878)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (5,282)	$ -	$ (5,282)	$ (3,738)
	Total	$ (10,762)	$ -	$ (10,762)	$ (7,616)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 3,242,763**	**$ (97,812)**	**$ 3,144,952**	**$ 2,225,515**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	March 2024 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (138,925)	$ -	$ (138,925)	$ (97,875)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (101,258)	$ -	$ (101,258)	$ (71,338)
3	Day-Ahead Supplemental Reserve	$ (31,366)	$ -	$ (31,366)	$ (22,098)
4	Real-Time Regulation Amount (See Note 1)	$ (68,680)	$ 76,720	$ 8,040	$ 5,664
5	Real-Time Spinning Reserve Amount	$ (16,701)	$ 51,974	$ 35,273	$ 24,850
6	Real-Time Supplemental Reserve Amount.	$ 38,628	$ 6,928	$ 45,556	$ 32,095
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 6,786	$ -	$ 6,786	$ 4,781
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ (374,261)	$ -	$ (374,261)	$ (263,672)
8b	Real Time Non Excessive Energy Congestion	$ (764,206)	$ -	$ (764,206)	$ (538,394)
8c	Real Time Non Excessive Energy Loss	$ (10,228)	$ -	$ (10,228)	$ (7,206)
9	Real Time Net Regulation Adjustment Amount	$ (1,501)	$ 1,515	$ 14	$ 10
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 101,141	$ -	$ 101,141	$ 71,255
11	Real Time Spinning Reserve Cost Distribution	$ 98,445	$ -	$ 98,445	$ 69,356
12	Real Time Supplemental Reserve Cost Distribution	$ 80,348	$ -	$ 80,348	$ 56,606
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 21,742	$ (18,743)	$ 2,999	$ 2,113
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ (1,160,038)**	**$ 118,394**	**$ (1,041,644)**	**$ (733,853)**

Ramp Capability Amounts (Included in Regulation Amounts)					
1	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (11,912)	$ -	$ (11,912)	$ (8,392)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (5,438)	$ -	$ (5,438)	$ (3,831)
	Total	$ (17,350)	$ -	$ (17,350)	$ (12,223)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ (1,142,689)**	**$ 118,394**	**$ (1,024,295)**	**$ (721,630)**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	April 2024 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (169,097)	$ -	$ (169,097)	$ (119,570)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (104,454)	$ -	$ (104,454)	$ (73,860)
3	Day-Ahead Supplemental Reserve	$ (38,061)	$ -	$ (38,061)	$ (26,913)
4	Real-Time Regulation Amount (See Note 1)	$ (10,595)	$ 94,027	$ 83,432	$ 58,995
5	Real-Time Spinning Reserve Amount	$ (24,007)	$ 62,936	$ 38,928	$ 27,527
6	Real-Time Supplemental Reserve Amount.	$ (6,005)	$ (102)	$ (6,107)	$ (4,318)
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 19,270	$ -	$ 19,270	$ 13,626
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ (863,820)	$ -	$ (863,820)	$ (610,813)
8b	Real Time Non Excessive Energy Congestion	$ (1,078,078)	$ -	$ (1,078,078)	$ (762,316)
8c	Real Time Non Excessive Energy Loss	$ 6,922	$ -	$ 6,922	$ 4,895
9	Real Time Net Regulation Adjustment Amount	$ 1,051	$ (839)	$ 211	$ 150
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 131,616	$ -	$ 131,616	$ 93,066
11	Real Time Spinning Reserve Cost Distribution	$ 102,058	$ -	$ 102,058	$ 72,166
12	Real Time Supplemental Reserve Cost Distribution	$ 102,889	$ -	$ 102,889	$ 72,754
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 12,823	$ (11,053)	$ 1,770	$ 1,252
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ (1,917,489)**	**$ 144,969**	**$ (1,772,521)**	**$ (1,253,361)**

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
1	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (19,440)	$ -	$ (19,440)	$ (13,746)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (5,702)	$ -	$ (5,702)	$ (4,032)
	Total	$ (25,142)	$ -	$ (25,142)	$ (17,778)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ (1,892,347)**	**$ 144,969**	**$ (1,747,378)**	**$ (1,235,583)**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	May 2024 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (314,863)	$ -	$ (314,863)	$ (227,642)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (202,749)	$ -	$ (202,749)	$ (146,585)
3	Day-Ahead Supplemental Reserve	$ (100,499)	$ -	$ (100,499)	$ (72,659)
4	Real-Time Regulation Amount (See Note 1)	$ (64,333)	$ 309,858	$ 245,524	$ 177,511
5	Real-Time Spinning Reserve Amount	$ (63,159)	$ 176,919	$ 113,761	$ 82,248
6	Real-Time Supplemental Reserve Amount.	$ 1,473	$ 5,367	$ 6,840	$ 4,945
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 25,957	$ -	$ 25,957	$ 18,767
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,040,852	$ -	$ 3,040,852	$ 2,198,496
8b	Real Time Non Excessive Energy Congestion	$ 239,383	$ -	$ 239,383	$ 173,071
8c	Real Time Non Excessive Energy Loss	$ 122,975	$ -	$ 122,975	$ 88,910
9	Real Time Net Regulation Adjustment Amount	$ 5,167	$ 33	$ 5,200	$ 3,760
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 120,934	$ -	$ 120,934	$ 87,434
11	Real Time Spinning Reserve Cost Distribution	$ 176,720	$ -	$ 176,720	$ 127,766
12	Real Time Supplemental Reserve Cost Distribution	$ 224,433	$ -	$ 224,433	$ 162,262
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 61,785	$ (44,385)	$ 17,400	$ 12,580
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 3,274,076**	**$ 447,792**	**$ 3,721,868**	**$ 2,690,861**

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
1	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (35,300)	$ -	$ (35,300)	$ (25,522)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (5,505)	$ -	$ (5,505)	$ (3,980)
	Total	$ (40,805)	$ -	$ (40,805)	$ (29,502)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 3,314,882**	**$ 447,792**	**$ 3,762,674**	**$ 2,720,363**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	June 2024	**Actual**			
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (331,628)	$ -	$ (331,628)	$ (239,080)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (167,400)	$ -	$ (167,400)	$ (120,683)
3	Day-Ahead Supplemental Reserve	$ (95,343)	$ -	$ (95,343)	$ (68,736)
4	Real-Time Regulation Amount (See Note 1)	$ (114,663)	$ 338,261	$ 223,598	$ 161,198
5	Real-Time Spinning Reserve Amount	$ (131,488)	$ 203,480	$ 71,992	$ 51,901
6	Real-Time Supplemental Reserve Amount.	$ 8,232	$ 8,883	$ 17,115	$ 12,339
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (40,648)	$ -	$ (40,648)	$ (29,305)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,906,295	$ -	$ 3,906,295	$ 2,816,161
8b	Real Time Non Excessive Energy Congestion	$ (723,860)	$ -	$ (723,860)	$ (521,851)
8c	Real Time Non Excessive Energy Loss	$ (101,726)	$ -	$ (101,726)	$ (73,337)
9	Real Time Net Regulation Adjustment Amount	$ (4,092)	$ (1,780)	$ (5,872)	$ (4,234)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 162,214	$ -	$ 162,214	$ 116,945
11	Real Time Spinning Reserve Cost Distribution	$ 105,145	$ -	$ 105,145	$ 75,802
12	Real Time Supplemental Reserve Cost Distribution	$ 90,967	$ -	$ 90,967	$ 65,581
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 95,207	$ (38,053)	$ 57,154	$ 41,204
14	Real Time Contingency Reserve Deployment Failure	$ 20,497	$ (406)	$ 20,091	$ 14,484
	TOTAL MISO ASM CHARGES	**$ 2,677,709**	**$ 510,384**	**$ 3,188,093**	**$ 2,298,389**

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
1	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (18,418)	$ -	$ (18,418)	$ (13,278)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,875)	$ -	$ (2,875)	$ (2,073)
	Total	$ (21,294)	$ -	$ (21,294)	$ (15,351)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 2,699,003**	**$ 510,384**	**$ 3,209,387**	**$ 2,313,740**

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	July 2024	**Actual**			
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (484,992)	$ -	$ (484,992)	$ (349,814)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (147,766)	$ -	$ (147,766)	$ (106,580)
3	Day-Ahead Supplemental Reserve	$ (371,951)	$ -	$ (371,951)	$ (268,280)
4	Real-Time Regulation Amount (See Note 1)	$ (186,908)	$ 611,165	$ 424,257	$ 306,008
5	Real-Time Spinning Reserve Amount	$ 34,934	$ 57,340	$ 92,273	$ 66,555
6	Real-Time Supplemental Reserve Amount.	$ 57,176	$ 2,743	$ 59,919	$ 43,218
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (3,947)	$ -	$ (3,947)	$ (2,847)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 6,612,394	$ -	$ 6,612,394	$ 4,769,382
8b	Real Time Non Excessive Energy Congestion	$ (249,855)	$ -	$ (249,855)	$ (180,215)
8c	Real Time Non Excessive Energy Loss	$ (77,217)	$ -	$ (77,217)	$ (55,695)
9	Real Time Net Regulation Adjustment Amount	$ 19,443	$ (15,227)	$ 4,216	$ 3,041
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 209,105	$ -	$ 209,105	$ 150,823
11	Real Time Spinning Reserve Cost Distribution	$ 165,663	$ -	$ 165,663	$ 119,489
12	Real Time Supplemental Reserve Cost Distribution	$ 747,727	$ -	$ 747,727	$ 539,320
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 95,636	$ (52,348)	$ 43,289	$ 31,223
14	Real Time Contingency Reserve Deployment Failure	$ (17,935)	$ -	$ (17,935)	$ (12,936)
	TOTAL MISO ASM CHARGES	**$ 6,401,507**	**$ 603,674**	**$ 7,005,181**	**$ 5,052,691**

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
1	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (7,006)	$ -	$ (7,006)	$ (5,053)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,191)	$ -	$ (2,191)	$ (1,580)
	Total	$ (9,196)	$ -	$ (9,196)	$ (6,633)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 6,410,704**	**$ 603,674**	**$ 7,014,377**	**$ 5,059,324**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	August 2024 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (564,435)	$ -	$ (564,435)	$ (405,213)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (145,346)	$ -	$ (145,346)	$ (104,346)
3	Day-Ahead Supplemental Reserve	$ (302,238)	$ -	$ (302,238)	$ (216,980)
4	Real-Time Regulation Amount (See Note 1)	$ (224,165)	$ 748,403	$ 524,238	$ 376,356
5	Real-Time Spinning Reserve Amount	$ (20,682)	$ 69,500	$ 48,818	$ 35,047
6	Real-Time Supplemental Reserve Amount.	$ (13,142)	$ 9,205	$ (3,937)	$ (2,826)
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (15,054)	$ -	$ (15,054)	$ (10,807)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 6,563,366	$ -	$ 6,563,366	$ 4,711,906
8b	Real Time Non Excessive Energy Congestion	$ 12,646	$ -	$ 12,646	$ 9,079
8c	Real Time Non Excessive Energy Loss	$ (140,445)	$ -	$ (140,445)	$ (100,827)
9	Real Time Net Regulation Adjustment Amount	$ 43,645	$ (32,438)	$ 11,207	$ 8,046
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 151,576	$ -	$ 151,576	$ 108,818
11	Real Time Spinning Reserve Cost Distribution	$ 76,190	$ -	$ 76,190	$ 54,698
12	Real Time Supplemental Reserve Cost Distribution	$ 269,715	$ -	$ 269,715	$ 193,631
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 127,441	$ (87,600)	$ 39,841	$ 28,602
14	Real Time Contingency Reserve Deployment Failure	$ 3,563	$ -	$ 3,563	$ 2,558
	TOTAL MISO ASM CHARGES	**$ 5,822,634**	**$ 707,071**	**$ 6,529,705**	**$ 4,687,740**

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
1	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (8,899)	$ -	$ (8,899)	$ (6,388)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (711)	$ -	$ (711)	$ (510)
	Total	$ (9,609)	$ -	$ (9,609)	$ (6,899)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 5,832,244**	**$ 707,071**	**$ 6,539,315**	**$ 4,694,639**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	September 2024 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (472,103)	$ -	$ (472,103)	$ (340,704)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (133,576)	$ -	$ (133,576)	$ (96,398)
3	Day-Ahead Supplemental Reserve	$ (83,426)	$ -	$ (83,426)	$ (60,207)
4	Real-Time Regulation Amount (See Note 1)	$ (194,399)	$ 424,294	$ 229,895	$ 165,909
5	Real-Time Spinning Reserve Amount	$ (1,603)	$ 58,571	$ 56,967	$ 41,112
6	Real-Time Supplemental Reserve Amount.	$ 5,139	$ 3,868	$ 9,007	$ 6,500
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (22,372)	$ -	$ (22,372)	$ (16,145)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,025,048	$ -	$ 2,025,048	$ 1,461,423
8b	Real Time Non Excessive Energy Congestion	$ (1,884,370)	$ -	$ (1,884,370)	$ (1,359,899)
8c	Real Time Non Excessive Energy Loss	$ (128,789)	$ -	$ (128,789)	$ (92,944)
9	Real Time Net Regulation Adjustment Amount	$ (1,944)	$ (7,202)	$ (9,146)	$ (6,600)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 226,698	$ -	$ 226,698	$ 163,602
11	Real Time Spinning Reserve Cost Distribution	$ 133,475	$ -	$ 133,475	$ 96,325
12	Real Time Supplemental Reserve Cost Distribution	$ 638,402	$ -	$ 638,402	$ 460,718
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 111,309	$ (72,732)	$ 38,577	$ 27,840
14	Real Time Contingency Reserve Deployment Failure	$ 10,652	$ -	$ 10,652	$ 7,687
	TOTAL MISO ASM CHARGES	**$ 228,140**	**$ 406,798**	**$ 634,938**	**$ 458,218**

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
1	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (7,386)	$ -	$ (7,386)	$ (5,330)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (3,194)	$ -	$ (3,194)	$ (2,305)
	Total	$ (10,580)	$ -	$ (10,580)	$ (7,635)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 238,720**	**$ 406,798**	**$ 645,518**	**$ 465,853**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	October 2024	**Actual**			
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (579,930)	$ -	$ (579,930)	$ (413,716)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (110,464)	$ -	$ (110,464)	$ (78,804)
3	Day-Ahead Supplemental Reserve	$ (58,162)	$ -	$ (58,162)	$ (41,492)
4	Real-Time Regulation Amount (See Note 1)	$ (199,352)	$ 504,003	$ 304,651	$ 217,335
5	Real-Time Spinning Reserve Amount	$ (24,501)	$ 61,153	$ 36,651	$ 26,147
6	Real-Time Supplemental Reserve Amount.	$ 1,511	$ 5,501	$ 7,011	$ 5,002
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 2,004	$ -	$ 2,004	$ 1,430
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,150,133	$ -	$ 2,150,133	$ 1,533,883
8b	Real Time Non Excessive Energy Congestion	$ (593,668)	$ -	$ (593,668)	$ (423,516)
8c	Real Time Non Excessive Energy Loss	$ (22,275)	$ -	$ (22,275)	$ (15,891)
9	Real Time Net Regulation Adjustment Amount	$ 24,255	$ (22,992)	$ 1,263	$ 901
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 268,712	$ -	$ 268,712	$ 191,696
11	Real Time Spinning Reserve Cost Distribution	$ 177,194	$ -	$ 177,194	$ 126,408
12	Real Time Supplemental Reserve Cost Distribution	$ 134,795	$ -	$ 134,795	$ 96,161
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 89,959	$ (48,783)	$ 41,176	$ 29,374
14	Real Time Contingency Reserve Deployment Failure		$ (4,484)	$ (4,484)	$ (3,199)
	TOTAL MISO ASM CHARGES	**$ 1,260,211**	**$ 494,397**	**$ 1,754,608**	**$ 1,251,720**

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
1	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (21,583)	$ -	$ (21,583)	$ (15,397)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (10,238)	$ -	$ (10,238)	$ (7,304)
	Total	$ (31,821)	$ -	$ (31,821)	$ (22,701)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 1,287,551**	**$ 498,877**	**$ 1,786,429**	**$ 1,274,420**

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	November 2024	**Actual**			
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (526,839)	$ -	$ (526,839)	$ (371,111)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (142,719)	$ -	$ (142,719)	$ (100,533)
3	Day-Ahead Supplemental Reserve	$ (29,060)	$ -	$ (29,060)	$ (20,470)
4	Real-Time Regulation Amount (See Note 1)	$ (373,069)	$ 657,454	$ 284,385	$ 200,324
5	Real-Time Spinning Reserve Amount	$ (20,514)	$ 81,902	$ 61,388	$ 43,243
6	Real-Time Supplemental Reserve Amount.	$ (2,847)	$ 3,303	$ 456	$ 321
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 162	$ -	$ 162	$ 114
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,870,986	$ -	$ 1,870,986	$ 1,317,940
8b	Real Time Non Excessive Energy Congestion	$ (376,676)	$ -	$ (376,676)	$ (265,334)
8c	Real Time Non Excessive Energy Loss	$ 49,526	$ -	$ 49,526	$ 34,886
9	Real Time Net Regulation Adjustment Amount	$ (43,032)	$ 25,147	$ (17,886)	$ (12,599)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 258,434	$ -	$ 258,434	$ 182,043
11	Real Time Spinning Reserve Cost Distribution	$ 139,078	$ -	$ 139,078	$ 97,968
12	Real Time Supplemental Reserve Cost Distribution	$ 38,208	$ -	$ 38,208	$ 26,914
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 75,957	$ (41,138)	$ 34,819	$ 24,527
14	Real Time Contingency Reserve Deployment Failure	$ 2,893	$ -	$ 2,893	$ 2,038
	TOTAL MISO ASM CHARGES	**$ 920,487**	**$ 726,668**	**$ 1,647,155**	**$ 1,160,271**

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
1	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (14,323)	$ -	$ (14,323)	$ (10,089)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (5,735)	$ -	$ (5,735)	$ (4,040)
	Total	$ (20,058)	$ -	$ (20,058)	$ (14,129)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 940,545**	**$ 726,668**	**$ 1,667,212**	**$ 1,174,400**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	December 2024 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (186,589)	$ -	$ (186,589)	$ (130,650)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (129,478)	$ -	$ (129,478)	$ (90,661)
3	Day-Ahead Supplemental Reserve	$ (60,015)	$ -	$ (60,015)	$ (42,023)
4	Real-Time Regulation Amount (See Note 1)	$ (338,603)	$ 328,922	$ (9,681)	$ (6,778)
5	Real-Time Spinning Reserve Amount	$ (21,637)	$ 93,852	$ 72,215	$ 50,565
6	Real-Time Supplemental Reserve Amount.	$ (28,047)	$ 7,902	$ (20,145)	$ (14,105)
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (17,310)	$ -	$ (17,310)	$ (12,120)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 10,454,283	$ -	$ 10,454,283	$ 7,320,107
8b	Real Time Non Excessive Energy Congestion	$ 139,519	$ -	$ 139,519	$ 97,691
8c	Real Time Non Excessive Energy Loss	$ 3,527	$ -	$ 3,527	$ 2,470
9	Real Time Net Regulation Adjustment Amount	$ 19,461	$ (6,417)	$ 13,045	$ 9,134
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 260,101	$ -	$ 260,101	$ 182,123
11	Real Time Spinning Reserve Cost Distribution	$ 146,913	$ -	$ 146,913	$ 102,869
12	Real Time Supplemental Reserve Cost Distribution	$ 150,923	$ -	$ 150,923	$ 105,676
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 40,489	$ (22,154)	$ 18,335	$ 12,838
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 10,433,537**	**$ 402,106**	**$ 10,835,644**	**$ 7,587,137**

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
1	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (12,971)	$ -	$ (12,971)	$ (9,082)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,903)	$ -	$ (2,903)	$ (2,033)
	Total	$ (15,874)	$ -	$ (15,874)	$ (11,115)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 10,449,411**	**$ 402,106**	**$ 10,851,518**	**$ 7,598,252**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	January - December 2024	**Actual**			
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (3,962,453)	$ -	$ (3,962,453)	$ (2,831,313)
2	Day-Ahead Spinning Reserve Amount	$ (1,746,406)	$ -	$ (1,746,406)	$ (1,244,053)
3	Day-Ahead Supplemental Reserve	$ (2,265,565)	$ -	$ (2,265,565)	$ (1,609,182)
4	Real-Time Regulation Amount	$ (1,957,308)	$ 5,134,526	$ 3,177,218	$ 2,264,154
5	Real-Time Spinning Reserve Amount	$ (330,083)	$ 1,197,478	$ 867,395	$ 617,371
6	Real-Time Supplemental Reserve Amount.	$ 123,471	$ 85,292	$ 208,762	$ 148,642
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (63,011)	$ -	$ (63,011)	$ (45,018)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 49,745,204	$ -	$ 49,745,204	$ 35,356,406
8b	Real Time Non Excessive Energy Congestion	$ (5,648,591)	$ -	$ (5,648,591)	$ (4,031,586)
8c	Real Time Non Excessive Energy Loss	$ (269,766)	$ -	$ (269,766)	$ (195,073)
9	Real Time Net Regulation Adjustment Amount	$ 21,530	$ (56,368)	$ (34,839)	$ (24,365)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 2,066,161	$ -	$ 2,066,161	$ 1,471,718
11	Real Time Spinning Reserve Cost Distribution	$ 1,495,698	$ -	$ 1,495,698	$ 1,066,019
12	Real Time Supplemental Reserve Cost Distribution	$ 3,037,291	$ -	$ 3,037,291	$ 2,171,510
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 812,470	$ (459,168)	$ 353,302	$ 252,269
14	Real Time Contingency Reserve Deployment Failure	$ 20,764	$ (4,890)	$ 15,874	$ 11,401
	TOTAL MISO ASM CHARGES	**$ 41,079,404**	**$ 5,896,869**	**$ 46,976,274**	**$ 33,378,901**

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
1	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (172,631)	$ -	$ (172,631)	$ (123,116)
4	Real-Time Ramp Capability Amount Included in RT Regulation Amount	$ (53,993)	$ -	$ (53,993)	$ (38,387)
	Total	$ (226,623)	$ -	$ (226,623)	$ (161,504)
		$ 41,301,547	**$ 5,901,349**	**$ 47,202,897**	**$ 33,540,405**

Northern States Power Company

SUMMARY OF MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES - SYSTEM

		January 24	February 24	March 24	1st Qt	April 24	May 24	June 24	2nd Qt	July 24	August 24	September 24	3rd Qt	October 24	November 24	December 24	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (121,696.98)	$ (71,354.62)	$ (138,925.39)	$ (331,976.99)	$ (169,097.43)	$ (314,863.27)	$ (331,627.63)	$ (815,588.33)	$ (484,991.65)	$ (564,434.95)	$ (472,102.88)	$ (1,521,529.48)	$ (579,930.07)	$ (526,839.45)	$ (186,589.05)	$ (1,293,358.57)	$ (3,962,453.37)
4	Real-Time Regulation Amount	$ (118,618.48)	$ (63,921.22)	$ (68,680.49)	$ (251,220.19)	$ (10,595.23)	$ (64,333.16)	$ (114,663.01)	$ (189,591.40)	$ (186,908.48)	$ (224,165.28)	$ (194,399.24)	$ (605,473.00)	$ (199,351.89)	$ (373,068.72)	$ (338,603.06)	$ (911,023.67)	$ (1,957,308.26)
10	Real Time Regulation Reserve Cost Distribution Amc	$ 67,130.15	$ 108,499.28	$ 101,140.64	$ 276,770.07	$ 131,615.88	$ 120,933.94	$ 162,214.10	$ 414,763.92	$ 209,105.37	$ 151,576.19	$ 226,698.16	$ 587,379.72	$ 268,711.77	$ 258,434.05	$ 260,101.44	$ 787,247.26	$ 2,066,160.97
	SUBTOTAL	$ (173,185.31)	$ (26,776.56)	$ (106,465.24)	$ (306,427.11)	$ (48,076.78)	$ (258,262.49)	$ (284,076.54)	$ (590,415.81)	$ (462,794.76)	$ (637,024.04)	$ (439,803.96)	$ (1,539,622.76)	$ (510,570.19)	$ (641,474.12)	$ (265,090.67)	$ (1,417,134.98)	$ (3,853,600.66)
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (240,616.17)	$ (120,579.81)	$ (101,257.81)	$ (462,453.79)	$ (104,454.22)	$ (202,748.90)	$ (167,399.61)	$ (474,602.73)	$ (147,765.91)	$ (145,346.38)	$ (133,576.32)	$ (426,688.61)	$ (110,463.54)	$ (142,719.34)	$ (129,478.31)	$ (382,661.19)	$ (1,746,406.32)
5	Real-Time Spinning Reserve Amount	$ (8,826.54)	$ (31,897.74)	$ (16,700.95)	$ (57,425.23)	$ (24,007.20)	$ (63,158.62)	$ (131,487.69)	$ (218,653.51)	$ 34,933.57	$ (20,682.09)	$ (1,603.45)	$ 12,648.03	$ (24,501.25)	$ (20,513.72)	$ (21,637.11)	$ (66,652.08)	$ (330,082.79)
11	Real Time Spinning Reserve Cost Distribution	$ 96,854.38	$ 77,962.88	$ 98,444.94	$ 273,262.20	$ 102,057.81	$ 176,720.01	$ 105,144.95	$ 383,922.77	$ 165,662.54	$ 76,190.22	$ 133,475.06	$ 375,327.82	$ 177,193.87	$ 139,078.11	$ 146,913.30	$ 463,185.28	$ 1,495,698.07
	SUBTOTAL	$ (152,588.33)	$ (74,514.67)	$ (19,513.82)	$ (246,616.82)	$ (26,403.61)	$ (89,187.51)	$ (193,742.35)	$ (309,333.47)	$ 52,830.20	$ (89,838.25)	$ (1,704.71)	$ (38,712.76)	$ 42,229.08	$ (24,154.95)	$ (4,202.12)	$ 13,872.01	$ (580,791.04)
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (1,057,722.91)	$ (37,720.82)	$ (31,366.19)	$ (1,126,809.92)	$ (38,061.39)	$ (100,498.65)	$ (95,343.42)	$ (233,903.46)	$ (371,950.55)	$ (302,237.96)	$ (83,426.30)	$ (757,614.81)	$ (58,162.17)	$ (29,059.74)	$ (60,015.12)	$ (147,237.03)	$ (2,265,565.22)
6	Real-Time Supplemental Reserve Amount.	$ 45,928.83	$ 15,425.75	$ 38,627.61	$ 99,982.19	$ (6,005.05)	$ 1,472.51	$ 8,231.66	$ 3,699.12	$ 57,176.17	$ (13,142.17)	$ 5,139.03	$ 49,173.03	$ 1,510.60	$ (2,847.19)	$ (28,047.00)	$ (29,383.59)	$ 123,470.75
12	Real Time Supplemental Reserve Cost Distribution	$ 650,346.81	$ (91,462.17)	$ 80,347.91	$ 639,232.55	$ 102,889.02	$ 224,432.64	$ 90,966.81	$ 418,288.47	$ 747,727.22	$ 269,714.51	$ 638,402.33	$ 1,655,844.06	$ 134,795.14	$ 38,207.78	$ 150,922.90	$ 323,925.82	$ 3,037,290.90
	SUBTOTAL	$ (361,447.27)	$ (113,757.24)	$ 87,609.33	$ (387,595.18)	$ 58,822.58	$ 125,406.50	$ 3,855.05	$ 188,084.13	$ 432,952.84	$ (45,665.62)	$ 560,115.06	$ 947,402.28	$ 78,143.57	$ 6,300.85	$ 62,860.78	$ 147,305.20	$ 895,196.43
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	$ 1,024.85	$ 69.46	$ -	$ 1,094.31	$ -	$ -	$ 20,497.44	$ 20,497.44	$ (17,935.26)	$ 3,563.09	$ 10,651.76	$ (3,720.41)	$ -	$ 2,892.77	$ -	$ 2,892.77	$ 20,764.11
13	Real Time Excessive/Deficient Energy Deployment	$ 67,585.53	$ 12,535.56	$ 21,741.77	$ 101,862.86	$ 12,823.48	$ 61,785.12	$ 95,207.13	$ 169,815.73	$ 95,636.44	$ 127,440.50	$ 111,309.03	$ 334,385.97	$ 89,958.72	$ 75,957.16	$ 40,489.12	$ 206,405.00	$ 812,469.56
9	Real Time Net Regulation Adjustment Amount	$ (52,218.17)	$ 11,294.32	$ (1,500.91)	$ (42,424.76)	$ 1,050.77	$ 5,167.14	$ (4,092.24)	$ 2,125.67	$ 19,443.01	$ 43,645.36	$ (1,943.79)	$ 61,144.58	$ 24,254.94	$ (43,032.13)	$ 19,461.35	$ 684.16	$ 21,529.65
	SUBTOTAL	$ 16,392.21	$ 23,899.34	$ 20,240.86	$ 60,532.41	$ 13,874.25	$ 66,952.26	$ 111,612.33	$ 192,438.84	$ 97,144.19	$ 174,648.95	$ 120,017.00	$ 391,810.14	$ 114,213.66	$ 35,817.80	$ 59,950.47	$ 209,981.93	$ 854,763.32
	TOTAL MISO ASM CHARGES	**$ (670,828.70)**	**$ (191,149.13)**	**$ (18,128.87)**	**$ (880,106.70)**	**$ (1,783.56)**	**$ (155,091.24)**	**$ (362,351.51)**	**$ (519,226.31)**	**$ 120,132.47**	**$ (597,878.96)**	**$ 238,623.39**	**$ (239,123.10)**	**$ (275,983.88)**	**$ (623,510.42)**	**$ (146,481.54)**	**$ (1,045,975.84)**	**$ (2,684,431.95)**
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ (22,937.86)	$ 5,080.22	$ 6,785.55	$ (11,072.09)	$ 19,270.19	$ 25,957.07	$ (40,648.40)	$ 4,578.86	$ (3,947.17)	$ (15,054.04)	$ (22,372.23)	$ (41,373.44)	$ 2,004.13	$ 161.65	$ (17,309.88)	$ (15,144.10)	$ (63,010.77)
7b	Real Time Excessive Energy Congestion				$ -				$ -				$ -				$ -	$ -
7c	Real Time Excessive Energy Loss				$ -				$ -				$ -				$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 10,853,148.82	$ 3,506,778.76	$ (374,260.85)	$ 13,985,666.73	$ (863,819.84)	$ 3,040,852.25	$ 3,906,294.93	$ 6,083,327.34	$ 6,612,393.84	$ 6,563,366.02	$ 2,025,048.15	$ 15,200,808.01	$ 2,150,133.20	$ 1,870,985.72	$ 10,454,282.73	$ 14,475,401.65	$ 49,745,203.73
8b	Real Time Non Excessive Energy Congestion	$ (274,754.09)	$ (94,673.29)	$ (764,205.66)	$ (1,133,633.04)	$ (1,078,078.12)	$ 239,382.76	$ (723,859.66)	$ (1,562,555.02)	$ (249,854.86)	$ 12,646.26	$ (1,884,369.71)	$ (2,121,578.31)	$ (593,667.52)	$ (376,675.71)	$ 139,518.82	$ (830,824.41)	$ (5,648,590.78)
8c	Real Time Non Excessive Energy Loss	$ 22,000.15	$ 5,964.39	$ (10,228.33)	$ 17,736.21	$ 6,921.92	$ 122,975.37	$ (101,726.29)	$ 28,171.00	$ (77,216.79)	$ (140,444.94)	$ (128,789.46)	$ (346,451.19)	$ (22,275.21)	$ 49,525.72	$ 3,527.35	$ 30,777.86	$ (269,766.12)
	SUBTOTAL	**$ 10,577,457.02**	**$ 3,423,150.08**	**$ (1,141,909.29)**	**$ 12,858,697.81**	**$ (1,915,705.85)**	**$ 3,429,167.45**	**$ 3,040,060.58**	**$ 4,553,522.18**	**$ 6,281,375.02**	**$ 6,420,513.30**	**$ (10,483.25)**	**$ 12,691,405.07**	**$ 1,536,194.60**	**$ 1,543,997.38**	**$ 10,580,019.02**	**$ 13,660,211.00**	**$ 43,763,836.06**
	GRAND TOTAL MISO ASM CHARGES	**$ 9,906,628.32**	**$ 3,232,000.95**	**$ (1,160,038.16)**	**$ 11,978,591.11**	**$ (1,917,489.41)**	**$ 3,274,076.21**	**$ 2,677,709.07**	**$ 4,034,295.87**	**$ 6,401,507.49**	**$ 5,822,634.34**	**$ 228,140.14**	**$ 12,452,281.97**	**$ 1,260,210.72**	**$ 920,486.96**	**$ 10,433,537.48**	**$ 12,614,235.16**	**$ 41,079,404.11**

Northern States Power Company

SUMMARY OF MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES - INTERSYSTEM

		January 24	February 24	March 24	1st Qt	April 24	May 24	June 24	2nd Qt	July 24	August 24	September 24	3rd Qt	October 24	November 24	December 24	4th Qt	YTD
	Regulation																	
1	Day-Ahead Regulation Amount				$ -				$ -				$ -				$ -	$ -
4	Real-Time Regulation Amount	$ 1,227,963.54	$ (186,544.95)	$ 76,719.99	$ 1,118,138.58	$ 94,027.03	$ 309,857.53	$ 338,261.18	$ 742,145.74	$ 611,165.31	$ 748,403.06	$ 424,293.86	$ 1,783,862.23	$ 504,002.70	$ 657,454.17	$ 328,922.36	$ 1,490,379.23	$ 5,134,525.78
10	Real Time Regulation Reserve Cost Distribution Amount				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 1,227,963.54	$ (186,544.95)	$ 76,719.99	$ 1,118,138.58	$ 94,027.03	$ 309,857.53	$ 338,261.18	$ 742,145.74	$ 611,165.31	$ 748,403.06	$ 424,293.86	$ 1,783,862.23	$ 504,002.70	$ 657,454.17	$ 328,922.36	$ 1,490,379.23	$ 5,134,525.78
	Spinning Reserve																	
2	Day-Ahead Spinning Reserve Amount				$ -				$ -				$ -				$ -	$ -
5	Real-Time Spinning Reserve Amount	$ 196,432.64	$ 83,419.87	$ 51,973.54	$ 331,826.05	$ 62,935.61	$ 176,919.39	$ 203,479.57	$ 443,334.57	$ 57,339.70	$ 69,499.94	$ 58,570.58	$ 185,410.22	$ 61,152.69	$ 81,902.16	$ 93,852.36	$ 236,907.21	$ 1,197,478.05
11	Real Time Spinning Reserve Cost Distribution				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 196,432.64	$ 83,419.87	$ 51,973.54	$ 331,826.05	$ 62,935.61	$ 176,919.39	$ 203,479.57	$ 443,334.57	$ 57,339.70	$ 69,499.94	$ 58,570.58	$ 185,410.22	$ 61,152.69	$ 81,902.16	$ 93,852.36	$ 236,907.21	$ 1,197,478.05
	Supplemental Reserve																	
3	Day-Ahead Supplemental Reserve				$ -				$ -				$ -				$ -	$ -
6	Real-Time Supplemental Reserve Amount.	$ 21,248.20	$ 10,444.38	$ 6,928.12	$ 38,620.70	$ (101.52)	$ 5,366.99	$ 8,883.45	$ 14,148.92	$ 2,743.02	$ 9,205.39	$ 3,867.89	$ 15,816.30	$ 5,500.65	$ 3,302.79	$ 7,902.20	$ 16,705.64	$ 85,291.56
12	Real Time Supplemental Reserve Cost Distribution				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 21,248.20	$ 10,444.38	$ 6,928.12	$ 38,620.70	$ (101.52)	$ 5,366.99	$ 8,883.45	$ 14,148.92	$ 2,743.02	$ 9,205.39	$ 3,867.89	$ 15,816.30	$ 5,500.65	$ 3,302.79	$ 7,902.20	$ 16,705.64	$ 85,291.56
	Other Charges																	
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -	$ -	$ -	$ (406.35)	$ (406.35)	$ -	$ -	$ -	$ -	$ (4,483.55)	$ -	$ -	$ (4,483.55)	$ (4,889.90)
13	Real Time Excessive/Deficient Energy Deployment	$ (15,837.93)	$ (6,341.31)	$ (18,743.09)	$ (40,922.33)	$ (11,053.15)	$ (44,385.02)	$ (38,053.24)	$ (93,491.41)	$ (52,347.86)	$ (87,599.57)	$ (72,731.88)	$ (212,679.31)	$ (48,782.95)	$ (41,138.19)	$ (22,153.70)	$ (112,074.84)	$ (459,167.89)
9	Real Time Net Regulation Adjustment Amount	$ 2,621.58	$ 1,210.43	$ 1,515.40	$ 5,347.41	$ (839.28)	$ 33.15	$ (1,780.24)	$ (2,586.37)	$ (15,226.60)	$ (32,437.99)	$ (7,202.29)	$ (54,866.88)	$ (22,992.20)	$ 25,146.62	$ (6,416.78)	$ (4,262.36)	$ (56,368.20)
	SUBTOTAL	$ (13,216.35)	$ (5,130.88)	$ (17,227.69)	$ (35,574.92)	$ (11,892.43)	$ (44,351.87)	$ (40,239.83)	$ (96,484.13)	$ (67,574.46)	$ (120,037.56)	$ (79,934.17)	$ (267,546.19)	$ (76,258.70)	$ (15,991.57)	$ (28,570.48)	$ (120,820.75)	$ (520,425.99)
	TOTAL MISO ASM CHARGES	$ 1,432,428.03	$ (97,811.58)	$ 118,393.96	$ 1,453,010.41	$ 144,968.69	$ 447,792.04	$ 510,384.37	$ 1,103,145.10	$ 603,673.57	$ 707,070.83	$ 406,798.16	$ 1,717,542.56	$ 494,397.34	$ 726,667.55	$ 402,106.44	$ 1,623,171.33	$ 5,896,869.40
	Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																	
7a	Real Time Excessive Energy Amount				$ -				$ -				$ -				$ -	$ -
7b	Real Time Excessive Energy Congestion				$ -				$ -				$ -				$ -	$ -
7c	Real Time Excessive Energy Loss				$ -				$ -				$ -				$ -	$ -
8a	Real Time Non Excessive Energy Amount				$ -				$ -				$ -				$ -	$ -
8b	Real Time Non Excessive Energy Congestion				$ -				$ -				$ -				$ -	$ -
8c	Real Time Non Excessive Energy Loss				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	GRAND TOTAL MISO ASM CHARGES	$ 1,432,428.03	$ (97,811.58)	$ 118,393.96	$ 1,453,010.41	$ 144,968.69	$ 447,792.04	$ 510,384.37	$ 1,103,145.10	$ 603,673.57	$ 707,070.83	$ 406,798.16	$ 1,717,542.56	$ 494,397.34	$ 726,667.55	$ 402,106.44	$ 1,623,171.33	$ 5,896,869.40

Northern States Power Company

SUMMARY OF MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES - RETAIL

		January 24	February 24	March 24	1st Qt	April 24	May 24	June 24	2nd Qt	July 24	August 24	September 24	3rd Qt	October 24	November 24	December 24	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (121,696.98)	$ (71,354.62)	$ (138,925.39)	$ (331,976.99)	$ (169,097.43)	$ (314,863.27)	$ (331,627.63)	$ (815,588.33)	$ (484,991.65)	$ (564,434.95)	$ (472,102.88)	$ (1,521,529.48)	$ (579,930.07)	$ (526,839.45)	$ (186,589.05)	$ (1,293,358.57)	$ (3,962,453.37)
4	Real-Time Regulation Amount	$ 1,109,345.06	$ (250,466.17)	$ 8,039.50	$ 866,918.39	$ 83,431.80	$ 245,524.37	$ 223,598.17	$ 552,554.34	$ 424,256.83	$ 524,237.78	$ 229,894.62	$ 1,178,389.23	$ 304,650.81	$ 284,385.45	$ (9,680.70)	$ 579,355.56	$ 3,177,217.52
10	Real Time Regulation Reserve Cost Distribution Amc	$ 67,130.15	$ 108,499.28	$ 101,140.64	$ 276,770.07	$ 131,615.88	$ 120,933.94	$ 162,214.10	$ 414,763.92	$ 209,105.37	$ 151,576.19	$ 226,698.16	$ 587,379.72	$ 268,711.77	$ 258,434.05	$ 260,101.44	$ 787,247.26	$ 2,066,160.97
	SUBTOTAL	$ 1,054,778.23	$ (213,321.51)	$ (29,745.25)	$ 811,711.47	$ 45,950.25	$ 51,595.04	$ 54,184.64	$ 151,729.93	$ 148,370.55	$ 111,379.02	$ (15,510.10)	$ 244,239.47	$ (6,567.49)	$ 15,980.05	$ 63,831.69	$ 73,244.25	$ 1,280,925.12
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (240,616.17)	$ (120,579.81)	$ (101,257.81)	$ (462,453.79)	$ (104,454.22)	$ (202,748.90)	$ (167,399.61)	$ (474,602.73)	$ (147,765.91)	$ (145,346.38)	$ (133,576.32)	$ (426,688.61)	$ (110,463.54)	$ (142,719.34)	$ (129,478.31)	$ (382,661.19)	$ (1,746,406.32)
5	Real-Time Spinning Reserve Amount	$ 187,606.10	$ 51,522.13	$ 35,272.59	$ 274,400.82	$ 38,928.41	$ 113,760.77	$ 71,991.88	$ 224,681.06	$ 92,273.27	$ 48,817.85	$ 56,967.13	$ 198,058.25	$ 36,651.44	$ 61,388.44	$ 72,215.25	$ 170,255.13	$ 867,395.26
11	Real Time Spinning Reserve Cost Distribution	$ 96,854.38	$ 77,962.88	$ 98,444.94	$ 273,262.20	$ 102,057.81	$ 176,720.01	$ 105,144.95	$ 383,922.77	$ 165,662.54	$ 76,190.22	$ 133,475.06	$ 375,327.82	$ 177,193.87	$ 139,078.11	$ 146,913.30	$ 463,185.28	$ 1,495,698.07
	SUBTOTAL	$ 43,844.31	$ 8,905.20	$ 32,459.72	$ 85,209.23	$ 36,532.00	$ 87,731.88	$ 9,737.22	$ 134,001.10	$ 110,169.90	$ (20,338.31)	$ 56,865.87	$ 146,697.46	$ 103,381.77	$ 57,747.21	$ 89,650.24	$ 250,779.22	$ 616,687.01
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (1,057,722.91)	$ (37,720.82)	$ (31,366.19)	$ (1,126,809.92)	$ (38,061.39)	$ (100,498.65)	$ (95,343.42)	$ (233,903.46)	$ (371,950.55)	$ (302,237.96)	$ (83,426.30)	$ (757,614.81)	$ (58,162.17)	$ (29,059.74)	$ (60,015.12)	$ (147,237.03)	$ (2,265,565.22)
6	Real-Time Supplemental Reserve Amount.	$ 67,177.03	$ 25,870.13	$ 45,555.73	$ 138,602.89	$ (6,106.57)	$ 6,839.50	$ 17,115.11	$ 17,848.04	$ 59,919.19	$ (3,936.78)	$ 9,006.92	$ 64,989.33	$ 7,011.25	$ 455.60	$ (20,144.80)	$ (12,677.95)	$ 208,762.31
12	Real Time Supplemental Reserve Cost Distribution	$ 650,346.81	$ (91,462.17)	$ 80,347.91	$ 639,232.55	$ 102,889.02	$ 224,432.64	$ 90,966.81	$ 418,288.47	$ 747,727.22	$ 269,714.51	$ 638,402.33	$ 1,655,844.06	$ 134,795.14	$ 38,207.78	$ 150,922.90	$ 323,925.82	$ 3,037,290.90
	SUBTOTAL	$ (340,199.07)	$ (103,312.86)	$ 94,537.45	$ (348,974.48)	$ 58,721.06	$ 130,773.49	$ 12,738.50	$ 202,233.05	$ 435,695.86	$ (36,460.23)	$ 563,982.95	$ 963,218.58	$ 83,644.22	$ 9,603.64	$ 70,762.98	$ 164,010.84	$ 980,487.99
Other Charges																		
13	Real Time Excessive/Deficient Energy Deployment	$ 1,024.85	$ 69.46	$ -	$ 1,094.31	$ -	$ -	$ 20,091.09	$ 20,091.09	$ (17,935.26)	$ 3,563.09	$ 10,651.76	$ (3,720.41)	$ (4,483.55)	$ 2,892.77	$ -	$ (1,590.78)	$ 15,874.21
14	Real Time Contingency Reserve Deployment Failure	$ 51,747.60	$ 6,194.25	$ 2,998.68	$ 60,940.53	$ 1,770.33	$ 17,400.10	$ 57,153.89	$ 76,324.32	$ 43,288.58	$ 39,840.93	$ 38,577.15	$ 121,706.66	$ 41,175.77	$ 34,818.97	$ 18,335.42	$ 94,330.16	$ 353,301.67
9	Real Time Net Regulation Adjustment Amount	$ (49,596.59)	$ 12,504.75	$ 14.49	$ (37,077.35)	$ 211.49	$ 5,200.29	$ (5,872.48)	$ (460.70)	$ 4,216.41	$ 11,207.37	$ (9,146.08)	$ 6,277.70	$ 1,262.74	$ (17,885.51)	$ 13,044.57	$ (3,578.20)	$ (34,838.55)
	SUBTOTAL	$ 3,175.86	$ 18,768.46	$ 3,013.17	$ 24,957.49	$ 1,981.82	$ 22,600.39	$ 71,372.50	$ 95,954.71	$ 29,569.73	$ 54,611.39	$ 40,082.83	$ 124,263.95	$ 37,954.96	$ 19,826.23	$ 31,379.99	$ 89,161.18	$ 334,337.33
	TOTAL MISO ASM CHARGES	**$ 761,599.33**	**$ (288,960.71)**	**$ 100,265.09**	**$ 572,903.71**	**$ 143,185.13**	**$ 292,700.80**	**$ 148,032.86**	**$ 583,918.79**	**$ 723,806.04**	**$ 109,191.87**	**$ 645,421.55**	**$ 1,478,419.46**	**$ 218,413.46**	**$ 103,157.13**	**$ 255,624.90**	**$ 577,195.49**	**$ 3,212,437.45**
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ (22,937.86)	$ 5,080.22	$ 6,785.55	$ (11,072.09)	$ 19,270.19	$ 25,957.07	$ (40,648.40)	$ 4,578.86	$ (3,947.17)	$ (15,054.04)	$ (22,372.23)	$ (41,373.44)	$ 2,004.13	$ 161.65	$ (17,309.88)	$ (15,144.10)	$ (63,010.77)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 10,853,148.82	$ 3,506,778.76	$ (374,260.85)	$ 13,985,666.73	$ (863,819.84)	$ 3,040,852.25	$ 3,906,294.93	$ 6,083,327.34	$ 6,612,393.84	$ 6,563,366.02	$ 2,025,048.15	$ 15,200,808.01	$ 2,150,133.20	$ 1,870,985.72	$ 10,454,282.73	$ 14,475,401.65	$ 49,745,203.73
8b	Real Time Non Excessive Energy Congestion	$ (274,754.09)	$ (94,673.29)	$ (764,205.66)	$ (1,133,633.04)	$ (1,078,078.12)	$ 239,382.76	$ (723,859.66)	$ (1,562,555.02)	$ (249,854.86)	$ 12,646.26	$ (1,884,369.71)	$ (2,121,578.31)	$ (593,667.52)	$ (376,675.71)	$ 139,518.82	$ (830,824.41)	$ (5,648,590.78)
8c	Real Time Non Excessive Energy Loss	$ 22,000.15	$ 5,964.39	$ (10,228.33)	$ 17,736.21	$ 6,921.92	$ 122,975.37	$ (101,726.29)	$ 28,171.00	$ (77,216.79)	$ (140,444.94)	$ (128,789.46)	$ (346,451.19)	$ (22,275.21)	$ 49,525.72	$ 3,527.35	$ 30,777.86	$ (269,766.12)
	SUBTOTAL	**$ 10,577,457.02**	**$ 3,423,150.08**	**$ (1,141,909.29)**	**$ 12,858,697.81**	**$ (1,915,705.85)**	**$ 3,429,167.45**	**$ 3,040,060.58**	**$ 4,553,522.18**	**$ 6,281,375.02**	**$ 6,420,513.30**	**$ (10,483.25)**	**$ 12,691,405.07**	**$ 1,536,194.60**	**$ 1,543,997.38**	**$ 10,580,019.02**	**$ 13,660,211.00**	**$ 43,763,836.06**
	GRAND TOTAL MISO ASM CHARGES	**$ 11,339,056.35**	**$ 3,134,189.37**	**$ (1,041,644.20)**	**$ 13,431,601.52**	**$ (1,772,520.72)**	**$ 3,721,868.25**	**$ 3,188,093.44**	**$ 5,137,440.97**	**$ 7,005,181.06**	**$ 6,529,705.17**	**$ 634,938.30**	**$ 14,169,824.53**	**$ 1,754,608.06**	**$ 1,647,154.51**	**$ 10,835,643.92**	**$ 14,237,406.49**	**$ 46,976,273.51**

Northern States Power Company

SUMMARY OF MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES - MINNESOTA RETAIL (WEIGHTED BY MWH SALES)

		January 24	February 24	March 24	1st Qt	April 24	May 24	June 24	2nd Qt	July 24	August 24	September 24	3rd Qt	October 24	November 24	December 24	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (85,443.86)	$ (50,493.86)	$ (97,874.92)	$ (233,812.65)	$ (119,569.92)	$ (227,641.97)	$ (239,079.98)	$ (586,291.86)	$ (349,814.36)	$ (405,213.45)	$ (340,703.98)	$ (1,095,731.79)	$ (413,716.24)	$ (371,110.69)	$ (130,649.98)	$ (915,476.90)	$ (2,831,313.21)
4	Real-Time Regulation Amount	$ 778,874.95	$ (177,241.57)	$ 5,663.94	$ 607,297.32	$ 58,995.18	$ 177,510.86	$ 161,198.41	$ 397,704.45	$ 306,007.60	$ 376,355.51	$ 165,908.78	$ 848,271.89	$ 217,334.80	$ 200,323.80	$ (6,778.44)	$ 410,880.16	$ 2,264,153.81
10	Real Time Regulation Reserve Cost Distribution Amc	$ 47,132.31	$ 76,779.16	$ 71,255.03	$ 195,166.50	$ 93,066.46	$ 87,433.64	$ 116,944.85	$ 297,444.95	$ 150,823.34	$ 108,818.05	$ 163,601.98	$ 423,243.37	$ 191,696.25	$ 182,043.39	$ 182,123.48	$ 555,863.12	$ 1,471,717.94
	SUBTOTAL	$ 740,563.39	$ (150,956.27)	$ (20,955.95)	$ 568,651.16	$ 32,491.73	$ 37,302.53	$ 39,063.28	$ 108,857.54	$ 107,016.58	$ 79,960.10	$ (11,193.22)	$ 175,783.46	$ (4,685.18)	$ 11,256.50	$ 44,695.06	$ 51,266.38	$ 904,558.54
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (168,937.43)	$ (85,327.91)	$ (71,337.58)	$ (325,602.92)	$ (73,860.27)	$ (146,584.77)	$ (120,683.23)	$ (341,128.27)	$ (106,580.47)	$ (104,345.61)	$ (96,398.45)	$ (307,324.52)	$ (78,803.57)	$ (100,532.85)	$ (90,660.94)	$ (269,997.36)	$ (1,244,053.07)
5	Real-Time Spinning Reserve Amount	$ 131,718.88	$ 36,459.47	$ 24,850.04	$ 193,028.39	$ 27,526.54	$ 82,247.53	$ 51,901.03	$ 161,675.10	$ 66,554.78	$ 35,046.82	$ 41,111.65	$ 142,713.25	$ 26,146.77	$ 43,242.60	$ 50,565.24	$ 119,954.61	$ 617,371.35
11	Real Time Spinning Reserve Cost Distribution	$ 68,001.79	$ 55,170.18	$ 69,355.87	$ 192,527.84	$ 72,165.76	$ 127,766.22	$ 75,802.04	$ 275,734.02	$ 119,488.93	$ 54,697.72	$ 96,325.37	$ 270,512.02	$ 126,408.31	$ 97,967.94	$ 102,868.95	$ 327,245.19	$ 1,066,019.07
	SUBTOTAL	$ 30,783.24	$ 6,301.74	$ 22,868.34	$ 59,953.31	$ 25,832.02	$ 63,428.99	$ 7,019.84	$ 96,280.85	$ 79,463.25	$ (14,601.07)	$ 41,038.57	$ 105,900.75	$ 73,751.51	$ 40,677.68	$ 62,773.25	$ 177,202.44	$ 439,337.35
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (742,630.86)	$ (26,693.02)	$ (22,097.93)	$ (791,421.80)	$ (26,913.46)	$ (72,659.19)	$ (68,735.84)	$ (168,308.49)	$ (268,280.17)	$ (216,979.63)	$ (60,206.52)	$ (545,466.33)	$ (41,492.30)	$ (20,469.96)	$ (42,022.69)	$ (103,984.95)	$ (1,609,181.57)
6	Real-Time Supplemental Reserve Amount.	$ 47,165.22	$ 18,306.91	$ 32,094.66	$ 97,566.80	$ (4,318.00)	$ 4,944.87	$ 12,338.78	$ 12,965.65	$ 43,218.46	$ (2,826.25)	$ 6,500.05	$ 46,892.26	$ 5,001.75	$ 320.93	$ (14,105.42)	$ (8,782.74)	$ 148,641.97
12	Real Time Supplemental Reserve Cost Distribution	$ 456,610.71	$ (64,722.91)	$ 56,606.25	$ 448,494.06	$ 72,753.51	$ 162,261.82	$ 65,580.61	$ 300,595.94	$ 539,320.05	$ 193,630.72	$ 460,717.83	$ 1,193,668.60	$ 96,161.49	$ 26,913.92	$ 105,676.48	$ 228,751.88	$ 2,171,510.49
	SUBTOTAL	$ (238,854.93)	$ (73,109.01)	$ 66,602.99	$ (245,360.95)	$ 41,522.05	$ 94,547.50	$ 9,183.55	$ 145,253.10	$ 314,258.33	$ (26,175.16)	$ 407,011.36	$ 695,094.54	$ 59,670.94	$ 6,764.89	$ 49,548.36	$ 115,984.19	$ 710,970.89
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	$ 719.55	$ 49.15	$ -	$ 768.70	$ -	$ -	$ 14,484.25	$ 14,484.25	$ (12,936.33)	$ 2,557.98	$ 7,687.09	$ (2,691.26)	$ (3,198.52)	$ 2,037.69	$ -	$ (1,160.82)	$ 11,400.87
13	Real Time Excessive/Deficient Energy Deployment	$ 36,332.17	$ 4,383.34	$ 2,112.61	$ 42,828.12	$ 1,251.81	$ 12,580.04	$ 41,203.90	$ 55,035.75	$ 31,223.15	$ 28,602.20	$ 27,840.09	$ 87,665.44	$ 29,374.38	$ 24,526.81	$ 12,838.49	$ 66,739.68	$ 252,269.00
9	Real Time Net Regulation Adjustment Amount	$ (34,821.93)	$ 8,848.95	$ 10.21	$ (25,962.78)	$ 149.55	$ 3,759.74	$ (4,233.64)	$ (324.35)	$ 3,041.21	$ 8,045.88	$ (6,600.48)	$ 4,486.61	$ 900.83	$ (12,598.72)	$ 9,133.83	$ (2,564.07)	$ (24,364.59)
	SUBTOTAL	$ 2,229.78	$ 13,281.44	$ 2,122.82	$ 17,634.04	$ 1,401.36	$ 16,339.78	$ 51,454.51	$ 69,195.65	$ 21,328.03	$ 39,206.06	$ 28,926.70	$ 89,460.79	$ 27,076.68	$ 13,965.78	$ 21,972.32	$ 63,014.79	$ 239,305.27
	TOTAL MISO ASM CHARGES	**$ 534,721.48**	**$ (204,482.10)**	**$ 70,638.19**	**$ 400,877.57**	**$ 101,247.16**	**$ 211,618.80**	**$ 106,721.18**	**$ 419,587.14**	**$ 522,066.20**	**$ 78,389.93**	**$ 465,783.41**	**$ 1,066,239.54**	**$ 155,813.95**	**$ 72,664.86**	**$ 178,989.00**	**$ 407,467.80**	**$ 2,294,172.05**
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ (16,104.75)	$ 3,595.00	$ 4,780.52	$ (7,729.23)	$ 13,626.08	$ 18,766.62	$ (29,304.61)	$ 3,088.09	$ (2,847.01)	$ (10,807.44)	$ (16,145.44)	$ (29,799.89)	$ 1,429.73	$ 113.87	$ (12,120.41)	$ (10,576.81)	$ (45,017.85)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 7,620,032.77	$ 2,481,560.56	$ (263,672.12)	$ 9,837,921.21	$ (610,812.75)	$ 2,198,495.86	$ 2,816,161.30	$ 4,403,844.41	$ 4,769,381.74	$ 4,711,905.61	$ 1,461,422.91	$ 10,942,710.26	$ 1,533,883.24	$ 1,317,940.03	$ 7,320,106.85	$ 10,171,930.12	$ 35,356,406.01
8b	Real Time Non Excessive Energy Congestion	$ (192,905.78)	$ (66,995.25)	$ (538,393.82)	$ (798,294.84)	$ (762,316.20)	$ 173,070.56	$ (521,851.42)	$ (1,111,097.06)	$ (180,215.10)	$ 9,078.88	$ (1,359,899.06)	$ (1,531,035.28)	$ (423,516.39)	$ (265,333.93)	$ 97,691.32	$ (591,159.01)	$ (4,031,586.19)
8c	Real Time Non Excessive Energy Loss	$ 15,446.38	$ 4,220.68	$ (7,206.00)	$ 12,461.06	$ 4,894.54	$ 88,909.56	$ (73,337.43)	$ 20,466.67	$ (55,694.86)	$ (100,826.82)	$ (92,943.90)	$ (249,465.57)	$ (15,890.91)	$ 34,886.39	$ 2,469.86	$ 21,465.33	$ (195,072.52)
	SUBTOTAL	**$ 7,426,468.62**	**$ 2,422,381.00**	**$ (804,491.43)**	**$ 9,044,358.19**	**$ (1,354,608.33)**	**$ 2,479,242.60**	**$ 2,191,667.83**	**$ 3,316,302.11**	**$ 4,530,624.77**	**$ 4,609,350.23**	**$ (7,565.48)**	**$ 9,132,409.52**	**$ 1,095,905.67**	**$ 1,087,606.35**	**$ 7,408,147.62**	**$ 9,591,659.63**	**$ 31,084,729.44**
	GRAND TOTAL MISO ASM CHARGES	**$ 7,961,190.10**	**$ 2,217,898.89**	**$ (733,853.24)**	**$ 9,445,235.76**	**$ (1,253,361.17)**	**$ 2,690,861.40**	**$ 2,298,389.02**	**$ 3,735,889.24**	**$ 5,052,690.96**	**$ 4,687,740.16**	**$ 458,217.93**	**$ 10,198,649.05**	**$ 1,251,719.61**	**$ 1,160,271.21**	**$ 7,587,136.61**	**$ 9,999,127.44**	**$ 33,378,901.49**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

January 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (121,697)	-	$ (24,770)	-	$ (96,927)		
2 Day-Ahead Spinning Reserve Amount	-	$ (240,616)	-	$ (44,184)	-	$ (196,433)		
3 Day-Ahead Supplemental Reserve	-	$ (33,075)	-	$ (11,827)	-	$ (21,248)		
4 Day-Ahead Short Term Reserve Amount	-	$ (1,024,647)	-	$ 106,389	-	$ (1,131,037)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (118,618)	-	$ (118,618)	-	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (8,827)	-	$ (8,827)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 2,219	-	$ 2,219	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ 43,710	-	$ 43,710	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,094)	$ (22,938)	(1,094)	$ (22,938)	-	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	277,171	$ 10,600,395	277,171	$ 10,600,395	-	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ (52,218)	-	$ (49,597)	-	$ (2,622)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 67,130	-	$ 67,130	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 96,854	-	$ 96,854	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 17,532	-	$ 17,532	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 632,815	-	$ 632,815	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 67,586	-	$ 51,748	-	$ 15,838		
14 Real Time Contingency Reserve Deployment Failure	-	$ 1,014	-	$ 1,014	-	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ 11	-	$ 11	-	$ 1		
MISO ASM CHARGES	276,077	$ 9,906,629	276,077	$ 11,339,056	-	$ (1,432,428)		
x Net Congestion Amount	-	$ (274,754)	-	$ (274,754)	-	$ -		
y Net Loss Amount	-	$ 22,000	-	$ 22,000	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 252,754	-	$ 252,754	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
Total MISO ASM CHARGES	**276,077**	**$ 9,906,629**	**276,077**	**$ 11,339,056**	**-**	**$ (1,432,428)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

February 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (71,355)	-	$ (51,828)	-	$ (19,527)		
2 Day-Ahead Spinning Reserve Amount	-	$ (120,580)	-	$ (37,160)	-	$ (83,420)		
3 Day-Ahead Supplemental Reserve	-	$ (21,447)	-	$ (11,003)	-	$ (10,444)		
4 Day-Ahead Short Term Reserve Amount	-	$ (16,273)	-	$ (222,345)	-	$ 206,072		
5 Real-Time Regulation Amount (See Note 1)	-	$ (63,921)	-	$ (63,921)	-	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (31,898)	-	$ (31,898)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 18,776	-	$ 18,776	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (3,350)	-	$ (3,350)	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(304)	$ 5,080	(304)	$ 5,080	-	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	116,730	$ 3,418,070	116,730	$ 3,418,070	-	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 11,294	-	$ 12,505	-	$ (1,210)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 108,499	-	$ 108,499	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 77,963	-	$ 77,963	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 10,275	-	$ 10,275	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ (101,738)	-	$ (101,738)	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 12,536	-	$ 6,194	-	$ 6,341		
14 Real Time Contingency Reserve Deployment Failure	-	$ 69	-	$ 69	-	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	116,426	$ 3,232,001	116,426	$ 3,134,189	-	$ 97,812		
x Net Congestion Amount	-	$ (94,673)	-	$ (94,673)	-	$ -		
y Net Loss Amount	-	$ 5,964	-	$ 5,964	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 88,709	-	$ 88,709	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
Total MISO ASM CHARGES	**116,426**	**$ 3,232,001**	**116,426**	**$ 3,134,189**	**-**	**$ 97,812**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

March 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (138,925)	-	$ (74,298)	-	$ (64,627)		
2 Day-Ahead Spinning Reserve Amount	-	$ (101,258)	-	$ (49,284)	-	$ (51,974)		
3 Day-Ahead Supplemental Reserve	-	$ (15,191)	-	$ (8,263)	-	$ (6,928)		
4 Day-Ahead Short Term Reserve Amount	-	$ (16,175)	-	$ (4,083)	-	$ (12,093)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (68,680)	-	$ (68,680)	-	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (16,701)	-	$ (16,701)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 41,658	-	$ 41,658	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (3,030)	-	$ (3,030)	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(355)	$ 6,786	(355)	$ 6,786	-	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	147,594	$ (1,148,695)	147,594	$ (1,148,695)	-	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ (1,501)	-	$ 14	-	$ (1,515)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 101,141	-	$ 101,141	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 98,445	-	$ 98,445	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 24,119	-	$ 24,119	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 56,229	-	$ 56,229	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 21,742	-	$ 2,999	-	$ 18,743		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	147,239	$ (1,160,038)	147,239	$ (1,041,644)	-	$ (118,394)		
x Net Congestion Amount	-	$ (764,206)	-	$ (764,206)	-	$ -		
y Net Loss Amount	-	$ (10,228)	-	$ (10,228)	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 774,434	-	$ 774,434	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
Total MISO ASM CHARGES	**147,239**	**$ (1,160,038)**	**147,239**	**$ (1,041,644)**	**-**	**$ (118,394)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

April 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (169,097)	-	$ (99,172)	-	$ (69,925)		
2 Day-Ahead Spinning Reserve Amount	-	$ (104,454)	-	$ (41,519)	-	$ (62,936)		
3 Day-Ahead Supplemental Reserve	-	$ (4,486)	-	$ (4,588)	-	$ 102		
4 Day-Ahead Short Term Reserve Amount	-	$ (33,575)	-	$ (9,473)	-	$ (24,102)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (10,595)	-	$ (10,595)	-	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (24,007)	-	$ (24,007)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ (812)	-	$ (812)	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (5,193)	-	$ (5,193)	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(476)	$ 19,270	(476)	$ 19,270	-	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	76,532	$ (1,934,976)	76,532	$ (1,934,976)	-	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 1,051	-	$ 211	-	$ 839		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 131,616	-	$ 131,616	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 102,058	-	$ 102,058	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 5,527	-	$ 5,527	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 97,362	-	$ 97,362	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 12,823	-	$ 1,770	-	$ 11,053		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	76,056	$ (1,917,489)	76,056	$ (1,772,521)	-	$ (144,969)		
x Net Congestion Amount	-	$ (1,078,078)	-	$ (1,078,078)	-	$ -		
y Net Loss Amount	-	$ 6,922	-	$ 6,922	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 1,071,156	-	$ 1,071,156	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
Total MISO ASM CHARGES	**76,056**	**$ (1,917,489)**	**76,056**	**$ (1,772,521)**	**-**	**$ (144,969)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

May 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (314,863)	-	$ (106,909)	-	$ (207,954)		
2 Day-Ahead Spinning Reserve Amount	-	$ (202,749)	-	$ (25,830)	-	$ (176,919)		
3 Day-Ahead Supplemental Reserve	-	$ (17,291)	-	$ (11,924)	-	$ (5,367)		
4 Day-Ahead Short Term Reserve Amount	-	$ (83,207)	-	$ 18,696	-	$ (101,903)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (64,333)	-	$ (64,333)	-	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (63,159)	-	$ (63,159)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 1,188	-	$ 1,188	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ 284	-	$ 284	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(844)	$ 25,957	(844)	$ 25,957	-	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	176,452	$ 3,403,210	176,452	$ 3,403,210	-	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 5,167	-	$ 5,200	-	$ (33)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 120,934	-	$ 120,934	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 176,720	-	$ 176,720	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 18,227	-	$ 18,227	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 206,205	-	$ 206,205	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 61,785	-	$ 17,400	-	$ 44,385		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	175,608	$ 3,274,076	175,608	$ 3,721,868	-	$ (447,792)		
x Net Congestion Amount	-	$ 239,383	-	$ 239,383	-	$ -		
y Net Loss Amount	-	$ 122,975	-	$ 122,975	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ (362,358)	-	$ (362,358)	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
Total MISO ASM CHARGES	**175,608**	**$ 3,274,076**	**175,608**	**$ 3,721,868**	**-**	**$ (447,792)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

June 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (331,628)	-	$ (55,357)	-	$ (276,270)		
2 Day-Ahead Spinning Reserve Amount	-	$ (167,400)	-	$ 36,080	-	$ (203,480)		
3 Day-Ahead Supplemental Reserve	-	$ (20,434)	-	$ (11,551)	-	$ (8,883)		
4 Day-Ahead Short Term Reserve Amount	-	$ (74,909)	-	$ (12,919)	-	$ (61,991)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (114,663)	-	$ (114,663)	-	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (131,488)	-	$ (131,488)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 7,475	-	$ 7,475	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ 757	-	$ 757	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(987)	$ (40,648)	(987)	$ (40,648)	-	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	181,370	$ 3,080,709	181,370	$ 3,080,709	-	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ (4,092)	-	$ (5,872)	-	$ 1,780		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 162,214	-	$ 162,214	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 105,145	-	$ 105,145	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 10,406	-	$ 10,406	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 80,561	-	$ 80,561	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 95,207	-	$ 57,154	-	$ 38,053		
14 Real Time Contingency Reserve Deployment Failure	-	$ 20,497	-	$ 20,091	-	$ 406		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	180,383	$ 2,677,709	180,383	$ 3,188,093	-	$ (510,384)		
x Net Congestion Amount	-	$ (723,860)	-	$ (723,860)	-	$ -		
y Net Loss Amount	-	$ (101,726)	-	$ (101,726)	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 825,586	-	$ 825,586	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
Total MISO ASM CHARGES	**180,383**	**$ 2,677,709**	**180,383**	**$ 3,188,093**	**-**	**$ (510,384)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

July 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (484,992)	-	$ (127,980)	-	$ (357,012)		
2 Day-Ahead Spinning Reserve Amount	-	$ (147,766)	-	$ (90,426)	-	$ (57,340)		
3 Day-Ahead Supplemental Reserve	-	$ (36,329)	-	$ (33,586)	-	$ (2,743)		
4 Day-Ahead Short Term Reserve Amount	-	$ (335,621)	-	$ (81,468)	-	$ (254,153)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (186,908)	-	$ (186,908)	-	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ 34,934	-	$ 34,934	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 12,550	-	$ 12,550	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ 44,626	-	$ 44,626	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(683)	$ (3,947)	(683)	$ (3,947)	-	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	240,799	$ 6,285,322	240,799	$ 6,285,322	-	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 19,443	-	$ 4,216	-	$ 15,227		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 209,105	-	$ 209,105	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 165,663	-	$ 165,663	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 66,030	-	$ 66,030	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 681,697	-	$ 681,697	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 95,636	-	$ 43,289	-	$ 52,348		
14 Real Time Contingency Reserve Deployment Failure	-	$ (17,935)	-	$ (17,935)	-	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	240,116	$ 6,401,507	240,116	$ 7,005,181	-	$ (603,674)		
x Net Congestion Amount	-	$ (249,855)	-	$ (249,855)	-	$ -		
y Net Loss Amount	-	$ (77,217)	-	$ (77,217)	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 327,072	-	$ 327,072	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
Total MISO ASM CHARGES	**240,116**	**$ 6,401,507**	**240,116**	**$ 7,005,181**	**-**	**$ (603,674)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

August 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (564,435)	-	$ (102,790)	-	$ (461,645)		
2 Day-Ahead Spinning Reserve Amount	-	$ (145,346)	-	$ (75,846)	-	$ (69,500)		
3 Day-Ahead Supplemental Reserve	-	$ (23,253)	-	$ (14,048)	-	$ (9,205)		
4 Day-Ahead Short Term Reserve Amount	-	$ (278,985)	-	$ 7,773	-	$ (286,758)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (224,165)	-	$ (224,165)	-	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (20,682)	-	$ (20,682)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 1,652	-	$ 1,652	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (14,795)	-	$ (14,795)	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(976)	$ (15,054)	(976)	$ (15,054)	-	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	279,277	$ 6,435,567	279,277	$ 6,435,567	-	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 43,645	-	$ 11,207	-	$ 32,438		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 151,576	-	$ 151,576	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 76,190	-	$ 76,190	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 33,118	-	$ 33,118	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 236,596	-	$ 236,596	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 127,441	-	$ 39,841	-	$ 87,600		
14 Real Time Contingency Reserve Deployment Failure	-	$ 3,563	-	$ 3,563	-	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	278,301	$ 5,822,634	278,301	$ 6,529,705	-	$ (707,071)		
x Net Congestion Amount	-	$ 12,646	-	$ 12,646	-	$ -		
y Net Loss Amount	-	$ (140,445)	-	$ (140,445)	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 127,799	-	$ 127,799	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
Total MISO ASM CHARGES	**278,301**	**$ 5,822,634**	**278,301**	**$ 6,529,705**	**-**	**$ (707,071)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

September 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (472,103)	-	$ (73,265)	-	$ (398,838)		
2 Day-Ahead Spinning Reserve Amount	-	$ (133,576)	-	$ (75,006)	-	$ (58,571)		
3 Day-Ahead Supplemental Reserve	-	$ (19,855)	-	$ (15,987)	-	$ (3,868)		
4 Day-Ahead Short Term Reserve Amount	-	$ (63,571)	-	$ (38,115)	-	$ (25,456)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (194,399)	-	$ (194,399)	-	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (1,603)	-	$ (1,603)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ (296)	-	$ (296)	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ 5,435	-	$ 5,435	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,056)	$ (22,372)	(1,056)	$ (22,372)	-	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	330,574	$ 11,889	330,574	$ 11,889	-	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ (1,944)	-	$ (9,146)	-	$ 7,202		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 226,698	-	$ 226,698	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 133,475	-	$ 133,475	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 19,757	-	$ 19,757	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 618,645	-	$ 618,645	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 111,309	-	$ 38,577	-	$ 72,732		
14 Real Time Contingency Reserve Deployment Failure	-	$ 893	-	$ 893	-	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ 9,759	-	$ 9,759	-	$ -		
MISO ASM CHARGES	329,518	$ 228,140	329,518	$ 634,938	-	$ (406,798)		
x Net Congestion Amount	-	$ (1,884,370)	-	$ (1,884,370)	-	$ -		
y Net Loss Amount	-	$ (128,789)	-	$ (128,789)	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 2,013,159	-	$ 2,013,159	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
Total MISO ASM CHARGES	**329,518**	**$ 228,140**	**329,518**	**$ 634,938**	**-**	**$ (406,798)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

October 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (579,930)	-	$ (118,529)	-	$ (461,401)		
2 Day-Ahead Spinning Reserve Amount	-	$ (110,464)	-	$ (49,311)	-	$ (61,153)		
3 Day-Ahead Supplemental Reserve	-	$ (16,686)	-	$ (11,185)	-	$ (5,501)		
4 Day-Ahead Short Term Reserve Amount	-	$ (41,476)	-	$ 1,125	-	$ (42,602)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (199,352)	-	$ (199,352)	-	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (24,501)	-	$ (24,501)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 2,407	-	$ 2,407	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (896)	-	$ (896)	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(415)	$ 2,004	(415)	$ 2,004	-	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	159,995	$ 1,534,190	159,995	$ 1,534,190	-	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 24,255	-	$ 1,263	-	$ 22,992		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 268,712	-	$ 268,712	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 177,194	-	$ 177,194	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 32,064	-	$ 32,064	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 102,731	-	$ 102,731	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 89,959	-	$ 41,176	-	$ 48,783		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ (4)	-	$ 4		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ (4,480)	-	$ 4,480		
MISO ASM CHARGES	159,580	$ 1,260,211	159,580	$ 1,754,608	-	$ (494,397)		
x Net Congestion Amount	-	$ (593,668)	-	$ (593,668)	-	$ -		
y Net Loss Amount	-	$ (22,275)	-	$ (22,275)	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 615,943	-	$ 615,943	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
Total MISO ASM CHARGES	**159,580**	**$ 1,260,211**	**159,580**	**$ 1,754,608**	**-**	**$ (494,397)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

November 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (526,839)	-	$ 119,575	-	$ (646,415)		
2 Day-Ahead Spinning Reserve Amount	-	$ (142,719)	-	$ (60,817)	-	$ (81,902)		
3 Day-Ahead Supplemental Reserve	-	$ (10,679)	-	$ (7,376)	-	$ (3,303)		
4 Day-Ahead Short Term Reserve Amount	-	$ (18,381)	-	$ (7,341)	-	$ (11,039)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (373,069)	-	$ (373,069)	-	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (20,514)	-	$ (20,514)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ (167)	-	$ (167)	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (2,680)	-	$ (2,680)	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(393)	$ 162	(393)	$ 162	-	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	127,629	$ 1,543,836	127,629	$ 1,543,836	-	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ (43,032)	-	$ (17,886)	-	$ (25,147)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 258,434	-	$ 258,434	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 139,078	-	$ 139,078	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 14,427	-	$ 14,427	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 23,781	-	$ 23,781	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 75,957	-	$ 34,819	-	$ 41,138		
14 Real Time Contingency Reserve Deployment Failure	-	$ 2,893	-	$ 2,893	-	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	127,235	$ 920,487	127,235	$ 1,647,155	-	$ (726,668)		
x Net Congestion Amount	-	$ (376,676)	-	$ (376,676)	-	$ -		
y Net Loss Amount	-	$ 49,526	-	$ 49,526	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 327,150	-	$ 327,150	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
Total MISO ASM CHARGES	**127,235**	**$ 920,487**	**127,235**	**$ 1,647,155**	**-**	**$ (726,668)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

December 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (186,589)	-	$ 60,968	-	$ (247,557)		
2 Day-Ahead Spinning Reserve Amount	-	$ (129,478)	-	$ (35,626)	-	$ (93,852)		
3 Day-Ahead Supplemental Reserve	-	$ (14,691)	-	$ (6,789)	-	$ (7,902)		
4 Day-Ahead Short Term Reserve Amount	-	$ (45,324)	-	$ 36,042	-	$ (81,366)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (338,603)	-	$ (338,603)	-	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (21,637)	-	$ (21,637)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 247	-	$ 247	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (28,294)	-	$ (28,294)	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(731)	$ (17,310)	(731)	$ (17,310)	-	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	327,283	$ 10,597,329	327,283	$ 10,597,329	-	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 19,461	-	$ 13,045	-	$ 6,417		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 260,101	-	$ 260,101	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 146,913	-	$ 146,913	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 21,088	-	$ 21,088	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 129,834	-	$ 129,834	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 40,489	-	$ 18,335	-	$ 22,154		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	326,552	$ 10,433,537	326,552	$ 10,835,644	-	$ (402,106)		
x Net Congestion Amount	-	$ 139,519	-	$ 139,519	-	$ -		
y Net Loss Amount	-	$ 3,527	-	$ 3,527	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ (143,046)	-	$ (143,046)	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
Total MISO ASM CHARGES	**326,552**	**$ 10,433,537**	**326,552**	**$ 10,835,644**	**-**	**$ (402,106)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

January - December 2024	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (3,962,453)	-	$ (654,356)	-	$ (3,308,097)		
2 Day-Ahead Spinning Reserve Amount	-	$ (1,746,406)	-	$ (548,928)	-	$ (1,197,478)		
3 Day-Ahead Supplemental Reserve	-	$ (233,419)	-	$ (148,127)	-	$ (85,292)		
4 Day-Ahead Short Term Reserve Amount	-	$ (2,032,147)	-	$ (205,718)	-	$ (1,826,428)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (1,957,308)	-	$ (1,957,308)	-	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (330,083)	-	$ (330,083)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 86,896	-	$ 86,896	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ 36,574	-	$ 36,574	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(8,314)	$ (63,011)	(8,314)	$ (63,011)	-	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	2,441,405	$ 43,826,847	2,441,405	$ 43,826,847	-	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 21,530	-	$ (34,839)	-	$ 56,368		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 2,066,161	-	$ 2,066,161	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 1,495,698	-	$ 1,495,698	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 272,572	-	$ 272,572	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 2,764,719	-	$ 2,764,719	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 812,470	-	$ 353,302	-	$ 459,168		
14 Real Time Contingency Reserve Deployment Failure	-	$ 10,995	-	$ 10,585	-	$ 410		
15 Real Time Short Term Reserve Deployment Failure	-	$ 9,770	-	$ 5,290	-	$ 4,481		
MISO ASM CHARGES	2,433,091	$ 41,079,405	2,433,091	$ 46,976,274	-	$ (5,896,869)		
x Net Congestion Amount	-	$ (5,648,591)	-	$ (5,648,591)	-	$ -		
y Net Loss Amount	-	$ (269,766)	-	$ (269,766)	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 5,918,357	-	$ 5,918,357	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
Total MISO ASM CHARGES	**2,433,091**	**$ 41,079,405**	**2,433,091**	**$ 46,976,274**	**-**	**$ (5,896,869)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	January 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(717,845)	$ (617,529)	3,557,814	$ 173,657,191	(3,329,327)	$ (134,436,861)			(946,332)	$ (39,837,859)				
5a	Day Ahead Non Asset Energy	(165,051)	$ (9,857,257)	2	$ 9	(165,053)	$ (9,857,266)					17,600	$ 976,187	-	$ -
13a	Real Time Asset Energy	23,389	$ 559,817	91,862	$ 3,143,803	(29,734)	$ (770,285)			(38,739)	$ (1,813,700)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(859,506)	$ (9,914,969)	3,649,678	$ 176,801,003	(3,524,113)	$ (145,064,413)	-	$ -	(985,071)	$ (41,651,559)	17,600	$ 976,187	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 11,807		$ 11,957		$ (150)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,877,644)		$ 27,311		$ (1,904,955)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,865,837)		$ 39,268		$ (1,905,105)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 534,014		$ 470,162		$ -		$ 63,851				$ 1,176		
19	Real Time Market Administration (Schedule 17)		$ 61,661		$ 59,562		$ (213)		$ 2,312				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 14,076		$ 14,076		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 104,778		$ 92,408		$ -		$ 12,370				$ 232		
34	Real -Time Schedule 24 Allocation Amount		$ 12,099		$ 12,131		$ (550)				$ 518		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 726,627		$ 648,338		$ (763)		$ 78,533		$ 518		$ 1,408		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 39,043		$ 61,847		$ (22,805)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (6,403,839)		$ 2,272,130		$ (8,675,969)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (501,954)		$ -		$ (501,954)								$ -
32	Financial Transmission Rights Yearly Allocation		$ (672,102)		$ 0		$ (672,102)						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 62,538		$ 62,538		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 7,396		$ 7,396		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (7,468,919)		$ 2,403,911		$ (9,872,830)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 121,773		$ 121,773				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (390,394)				$ (183,878)				$ (206,515)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 455,656		$ 455,656				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (499,147)		$ 7		$ (202,986)				$ (296,167)				
43	Real Time Price Volatility Make Whole Payment		$ (120,998)		$ 66		$ (94,732)				$ (26,332)				
	SUBTOTAL		$ (433,109)		$ 577,502		$ (481,597)		$ -		$ (529,014)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 207,731		$ 207,926		$ (196)				$ -		$ -		
21	Real Time Net Inadvertent Distribution		$ (802)		$ 298,627		$ (299,429)						$ 703		$ (708)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,779,997		$ 2,516,771		$ (736,774)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,986,926		$ 3,023,325		$ (1,036,399)		$ -		$ -		$ 703		$ (708)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 5,449,448		$ 5,486,859		$ (37,411)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (5,468,626)		$ 37,349		$ (5,505,975)				$ -				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (1,256,028)		$ -		$ (1,256,028)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 85,853		$ 85,853		$ -								
	SUBTOTAL		$ (1,189,354)		$ 5,610,060		$ (6,799,414)		$ -		$ -		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (39,043)		$ 22,805		$ (61,847)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (11,807)		$ 150		$ (11,957)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ (50,850)	-	$ 22,955	-	$ (73,805)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(859,506)	$ (18,209,486)	3,649,678	$ 189,126,362	(3,524,113)	$ (165,234,325)	-	$ 78,533	(985,071)	$ (42,180,056)	17,600	$ 978,297	-	$ (708)
x	Net Congestion Amount		$ 15,751,198		$ 15,751,198				$ -						
y	Net Loss Amount		$ 8,651,939		$ 8,651,939				$ -						
z	Net Congestion and Loss Energy Offset		$ (24,403,137)		$ (24,403,137)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(859,506)**	$ (18,209,486)	3,649,678	$ 189,126,362	(3,524,113)	$ (165,234,325)	-	$ 78,533	(985,071)	$ (42,180,056)	17,600	$ 978,297	-	$ (708)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	February 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(698,651)	$ 4,982,951	3,072,241	$ 67,927,729	(2,927,901)	$ (50,238,923)			(842,991)	$ (12,705,855)				
5a	Day Ahead Non Asset Energy	(153,147)	$ (3,570,871)	55	$ 934	(153,202)	$ (3,571,806)					16,800	$ 433,456	-	$ -
13a	Real Time Asset Energy	(85,691)	$ (1,446,929)	4,959	$ 383,011	(6,174)	$ (868,278)			(84,476)	$ (961,663)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(937,489)	$ (34,849)	3,077,255	$ 68,311,675	(3,087,276)	$ (54,679,007)	-	$ -	(927,467)	$ (13,667,517)	16,800	$ 433,456	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 5,394		$ 5,811		$ (417)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (444,130)		$ 130,156		$ (574,285)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (438,736)		$ 135,967		$ (574,703)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 775,220		$ 681,958		$ -		$ 93,263				$ 1,861		
19	Real Time Market Administration (Schedule 17)		$ 90,313		$ 82,352		$ (1,349)		$ 9,309				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 22,577		$ 22,577		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 91,655		$ 80,617		$ -		$ 11,038				$ 222		
34	Real -Time Schedule 24 Allocation Amount		$ 10,520		$ 10,713		$ (1,303)				$ 1,110		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 990,286		$ 878,216		$ (2,651)		$ 113,611		$ 1,110		$ 2,083		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 29,683		$ 30,349		$ (666)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (1,253,003)		$ 1,127,819		$ (2,380,822)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ 367,019		$ -		$ 367,019								$ -
32	Financial Transmission Rights Yearly Allocation		$ 0		$ 0		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 227,045		$ 227,045		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (250,280)		$ -		$ (250,280)						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (879,536)		$ 1,385,213		$ (2,264,749)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 68,877		$ 68,877				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ 3,038				$ (5,564)				$ 8,602				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ (89,633)		$ (89,633)				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (573)		$ -		$ 909				$ (1,482)				
43	Real Time Price Volatility Make Whole Payment		$ (420,308)		$ -		$ (331,137)				$ (89,172)				
	SUBTOTAL		$ (438,600)		$ (20,757)		$ (335,792)		$ -		$ (82,052)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (3,771,681)		$ 46,767		$ (3,818,447)				$ -		$ 314		
21	Real Time Net Inadvertent Distribution		$ 57,996		$ 109,173		$ (51,177)						$ 244		$ (125)
23	Real Time Revenue Neutrality Uplift Amount		$ 409,305		$ 643,127		$ (233,822)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ (3,304,380)		$ 799,067		$ (4,103,447)		$ -		$ -		$ 557		$ (125)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 5,449,448		$ 5,486,859		$ (37,411)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (5,468,626)		$ 37,349		$ (5,505,975)				$ -				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (1,256,028)		$ -		$ (1,256,028)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 85,853		$ 85,853		$ -								
	SUBTOTAL		$ (1,189,354)		$ 5,610,060		$ (6,799,414)		$ -		$ -		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (29,683)		$ 666		$ (30,349)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (5,394)		$ 417		$ (5,811)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ (35,077)	-	$ 1,083	-	$ (36,160)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(937,489)	$ (5,330,246)	3,077,255	$ 77,100,525	(3,087,276)	$ (68,795,922)	-	$ 113,611	(927,467)	$ (13,748,459)	16,800	$ 436,097	-	$ (125)
x	Net Congestion Amount		$ 10,310,672		$ 10,310,672				$ -						
y	Net Loss Amount		$ 3,045,755		$ 3,045,755				$ -						
z	Net Congestion and Loss Energy Offset		$ (13,356,428)		$ (13,356,428)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(937,489)**	$ (5,330,246)	3,077,255	$ 77,100,525	(3,087,276)	$ (68,795,922)	-	$ 113,611	(927,467)	$ (13,748,459)	16,800	$ 436,097	-	$ (125)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	March 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(1,097,391)	$ 6,018,002	3,105,435	$ 60,450,265	(3,083,887)	$ (39,993,731)			(1,118,939)	$ (14,438,532)				
5a	Day Ahead Non Asset Energy	(164,569)	$ (2,844,519)	52	$ 719	(164,621)	$ (2,845,238)					-	$ -	-	$ -
13a	Real Time Asset Energy	(30,009)	$ (467,132)	48,165	$ 1,128,463	15,257	$ (524,306)			(93,430)	$ (1,071,289)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,291,969)	$ 2,706,351	3,153,652	$ 61,579,447	(3,233,251)	$ (43,363,275)	-	$ -	(1,212,369)	$ (15,509,821)	-	$ -	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 2,065		$ 2,512		$ (447)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,130,969)		$ 41,393		$ (1,172,362)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,128,903)		$ 43,905		$ (1,172,808)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 547,667		$ 465,647		$ -		$ 82,020				$ 0		
19	Real Time Market Administration (Schedule 17)		$ 50,580		$ 44,139		$ (410)		$ 6,851				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 17,146		$ 17,146		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 98,654		$ 83,882		$ -		$ 14,772				$ 0		
34	Real -Time Schedule 24 Allocation Amount		$ 9,542		$ 9,613		$ (1,302)				$ 1,231		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 723,590		$ 620,427		$ (1,711)		$ 103,643		$ 1,231		$ 0		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 25,319		$ 28,004		$ (2,686)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (1,967,141)		$ 3,031,356		$ (4,998,497)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (330,451)		$ -		$ (330,451)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (254,146)		$ -		$ (254,146)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 250,023		$ 250,023		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (2,276,396)		$ 3,309,384		$ (5,585,780)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 61,809		$ 61,809				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (95,486)				$ (8,500)				$ (86,986)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 31,564		$ 31,564				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (33,000)		$ -		$ (9,946)				$ (23,054)				
43	Real Time Price Volatility Make Whole Payment		$ (92,518)		$ -		$ (43,052)				$ (49,466)				
	SUBTOTAL		$ (127,631)		$ 93,373		$ (61,498)		$ -		$ (159,506)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 170,634		$ 220,456		$ (49,823)				$ -		$ (36)		
21	Real Time Net Inadvertent Distribution		$ (420,130)		$ 191,158		$ (611,288)						$ 14		$ (79)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,050,618		$ 1,548,513		$ (497,895)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 801,122		$ 1,960,128		$ (1,159,006)		$ -		$ -		$ (22)		$ (79)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 4,814,922		$ 5,157,345		$ (342,423)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (4,838,171)		$ 320,999		$ (5,159,170)				$ -				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (1,016,112)		$ -		$ (1,016,112)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 122,929		$ 122,929		$ -								
	SUBTOTAL		$ (916,431)		$ 5,601,274		$ (6,517,705)		$ -		$ -		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (24,807)		$ 2,686		$ (27,492)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (2,352)		$ 161		$ (2,512)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ (27,158)	-	$ 2,846	-	$ (30,004)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,291,969)	$ (245,456)	3,153,652	$ 73,210,783	(3,233,251)	$ (57,891,787)	-	$ 103,643	(1,212,369)	$ (15,668,095)	-	$ (22)	-	$ (79)
x	Net Congestion Amount		$ 16,950,981		$ 16,950,981				$ -						
y	Net Loss Amount		$ 3,069,654		$ 3,069,654				$ -						
z	Net Congestion and Loss Energy Offset		$ (20,020,636)		$ (20,020,636)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,291,969)**	$ (245,456)	3,153,652	$ 73,210,783	(3,233,251)	$ (57,891,787)	-	$ 103,643	(1,212,369)	$ (15,668,095)	-	$ (22)	-	$ (79)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Docket No. E002/AA-23-153
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	April 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(1,082,868)	$ 25,529,953	2,886,707	$ 55,452,747	(2,783,746)	$ (24,492,634)			(1,185,829)	$ (5,430,160)				
5a	Day Ahead Non Asset Energy	(172,742)	$ (2,714,158)	49	$ 733	(172,791)	$ (2,714,891)					-	$ -	-	$ -
13a	Real Time Asset Energy	(24,576)	$ (192,461)	49,335	$ 1,211,818	63,472	$ 117,021			(137,383)	$ (1,521,299)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,280,187)	$ 22,623,334	2,936,091	$ 56,665,298	(2,893,065)	$ (27,090,504)	-	$ -	(1,323,212)	$ (6,951,459)	-	$ -	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 837		$ 1,500		$ (663)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (664,137)		$ (38,946)		$ (625,191)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (663,300)		$ (37,446)		$ (625,854)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 732,365		$ 611,398		$ -		$ 120,967				$ -		
19	Real Time Market Administration (Schedule 17)		$ 75,966		$ 62,654		$ (420)		$ 13,732				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 16,523		$ 16,523		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 99,104		$ 82,446		$ -		$ 16,659				$ -		
34	Real -Time Schedule 24 Allocation Amount		$ 10,267		$ 10,338		$ (1,980)				$ 1,909		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 934,225		$ 783,358		$ (2,400)		$ 151,358		$ 1,909		$ -		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 43,681		$ 45,304		$ (1,623)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (9,478,401)		$ 7,841,175		$ (17,319,577)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (1,184,374)		$ -		$ (1,184,374)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (1,480,239)		$ -		$ (1,480,239)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 1,460,939		$ 1,460,939		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (10,638,394)		$ 9,347,419		$ (19,985,813)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 65,228		$ 65,228				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (66,275)				$ (5,623)				$ (60,652)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 29,988		$ 29,988				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (52,524)		$ -		$ (16,828)				$ (35,697)				
43	Real Time Price Volatility Make Whole Payment		$ (395,573)		$ -		$ (281,766)				$ (113,806)				
	SUBTOTAL		$ (419,156)		$ 95,216		$ (304,217)		$ -		$ (210,154)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 169,638		$ 172,832		$ (3,194)				$ -		$ -		
21	Real Time Net Inadvertent Distribution		$ 194,526		$ 151,700		$ 42,826						$ 25		$ (12)
23	Real Time Revenue Neutrality Uplift Amount		$ 740,008		$ 1,303,189		$ (563,180)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,104,172		$ 1,627,721		$ (523,548)		$ -		$ -		$ 25		$ (12)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 4,814,922		$ 5,157,345		$ (342,423)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (4,838,171)		$ 320,999		$ (5,159,170)				$ -				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (1,016,414)		$ 0		$ (1,016,414)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 122,731		$ 122,731		$ -								
	SUBTOTAL		$ (916,932)		$ 5,601,076		$ (6,518,007)		$ -		$ -		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (43,681)		$ 1,623		$ (45,304)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (837)		$ 663		$ (1,500)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ (44,519)	-	$ 2,286	-	$ (46,805)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,280,187)	$ 11,979,433	2,936,091	$ 74,084,927	(2,893,065)	$ (55,097,148)	-	$ 151,358	(1,323,212)	$ (7,159,705)	-	$ 25	-	$ (12)
x	Net Congestion Amount		$ 25,415,497		$ 25,415,497				$ -						
y	Net Loss Amount		$ 2,824,631		$ 2,824,631				$ -						
z	Net Congestion and Loss Energy Offset		$ (28,240,128)		$ (28,240,128)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,280,187)**	$ 11,979,433	2,936,091	$ 74,084,927	(2,893,065)	$ (55,097,148)	-	$ 151,358	(1,323,212)	$ (7,159,705)	-	$ 25	-	$ (12)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	May 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(1,039,645)	$ (1,795,719)	3,012,345	$ 69,325,148	(2,828,239)	$ (52,251,124)			(1,223,751)	$ (18,869,743)				
5a	Day Ahead Non Asset Energy	(238,186)	$ (6,059,219)	68	$ 1,570	(238,254)	$ (6,060,789)					-	$ -	-	$ -
13a	Real Time Asset Energy	21,146	$ 899,649	73,667	$ 1,979,152	56,103	$ 688,710			(108,624)	$ (1,768,214)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,256,686)	$ (6,955,289)	3,086,079	$ 71,305,870	(3,010,390)	$ (57,623,203)	-	$ -	(1,332,375)	$ (20,637,956)	-	$ -	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 1,480		$ 2,421		$ (941)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (230,895)		$ 325,016		$ (555,912)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (229,415)		$ 327,437		$ (556,853)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 672,568		$ 560,019		$ -		$ 112,549				$ -		
19	Real Time Market Administration (Schedule 17)		$ 74,750		$ 65,075		$ (281)		$ 9,956				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 16,608		$ 16,608		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 97,855		$ 81,456		$ -		$ 16,399				$ -		
34	Real -Time Schedule 24 Allocation Amount		$ 10,879		$ 10,934		$ (1,510)				$ 1,455		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 872,661		$ 734,093		$ (1,791)		$ 138,905		$ 1,455		$ -		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 14,044		$ 24,043		$ (9,998)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ 392,791		$ 5,929,565		$ (5,536,773)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ 770,859		$ -		$ 770,859								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (280,222)		$ -		$ (280,222)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 291,287		$ 291,287		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ 1,188,760		$ 6,244,894		$ (5,056,135)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 50,714		$ 50,714				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (113,348)				$ (66,617)				$ (46,731)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 36,831		$ 36,831				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ 1,118		$ -		$ 1,380				$ (262)				
43	Real Time Price Volatility Make Whole Payment		$ (217,487)		$ 553		$ (122,118)				$ (95,922)				
	SUBTOTAL		$ (242,173)		$ 88,097		$ (187,355)		$ -		$ (142,914)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 175,834		$ 176,424		$ (590)				$ -		$ -		
21	Real Time Net Inadvertent Distribution		$ 220,404		$ 264,192		$ (43,788)						$ 4		$ (1)
23	Real Time Revenue Neutrality Uplift Amount		$ 451,059		$ 1,194,327		$ (743,267)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 847,297		$ 1,634,942		$ (787,645)		$ -		$ -		$ 4		$ (1)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 4,814,922		$ 5,157,345		$ (342,423)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (4,838,171)		$ 320,999		$ (5,159,170)				$ -				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (6,098,486)		$ -		$ (6,098,486)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 736,335		$ 736,335		$ -								
	SUBTOTAL		$ (5,385,399)		$ 6,214,680		$ (11,600,079)		$ -		$ -		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (14,044)		$ 9,998		$ (24,043)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,480)		$ 941		$ (2,421)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ (15,524)	-	$ 10,939	-	$ (26,464)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,256,686)	$ (9,919,083)	3,086,079	$ 86,560,952	(3,010,390)	$ (75,839,524)	-	$ 138,905	(1,332,375)	$ (20,779,416)	-	$ 4	-	$ (1)
x	Net Congestion Amount		$ 8,684,344		$ 8,684,344				$ -						
y	Net Loss Amount		$ 2,656,518		$ 2,656,518				$ -						
z	Net Congestion and Loss Energy Offset		$ (11,340,862)		$ (11,340,862)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,256,686)**	$ (9,919,083)	3,086,079	$ 86,560,952	(3,010,390)	$ (75,839,524)	-	$ 138,905	(1,332,375)	$ (20,779,416)	-	$ 4	-	$ (1)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	June 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(1,066,408)	$ (6,481,397)	3,371,252	$ 76,762,840	(3,151,774)	$ (59,853,763)			(1,285,886)	$ (23,390,473)				
5a	Day Ahead Non Asset Energy	(257,341)	$ (6,687,665)	-	$ 1	(257,341)	$ (6,687,666)					8,000	$ 217,315	(1,600)	$ (43,463)
13a	Real Time Asset Energy	(23,255)	$ (4,153)	61,580	$ 1,611,361	8,066	$ (195,793)			(92,900)	$ (1,419,722)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,347,004)	$ (13,173,215)	3,432,831	$ 78,374,202	(3,401,049)	$ (66,737,223)	-	$ -	(1,378,786)	$ (24,810,195)	8,000	$ 217,315	(1,600)	$ (43,463)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (2,234)		$ 769		$ (3,002)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,232,637)		$ (13,009)		$ (1,219,628)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,234,871)		$ (12,240)		$ (1,222,631)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 634,612		$ 533,281		$ -		$ 101,330				$ 755		
19	Real Time Market Administration (Schedule 17)		$ 64,581		$ 57,641		$ (221)		$ 7,161				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 17,865		$ 17,865		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 104,863		$ 88,145		$ -		$ 16,718				$ 125		
34	Real -Time Schedule 24 Allocation Amount		$ 10,688		$ 10,723		$ (1,243)				$ 1,207		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 832,608		$ 707,655		$ (1,464)		$ 125,210		$ 1,207		$ 880		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (16)		$ 8,711		$ (8,726)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (486,341)		$ 1,566,139		$ (2,052,480)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ 382,449		$ -		$ 382,449								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 43,128		$ 43,128		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 10,650		$ 10,650		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (50,130)		$ 1,628,627		$ (1,678,757)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 42,191		$ 42,191				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (109,716)				$ (51,156)				$ (58,560)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 31,815		$ 31,815				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (41,559)		$ -		$ (29,893)				$ (11,666)				
43	Real Time Price Volatility Make Whole Payment		$ (42,799)		$ 10,621		$ (34,269)				$ (19,150)				
	SUBTOTAL		$ (120,068)		$ 84,626		$ (115,319)		$ -		$ (89,376)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 172,904		$ 172,919		$ (16)				$ -		$ -		
21	Real Time Net Inadvertent Distribution		$ (128,324)		$ 114,611		$ (242,935)						$ 124		$ (279)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,064,074		$ 1,353,714		$ (289,641)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,108,653		$ 1,641,244		$ (532,591)		$ -		$ -		$ 124		$ (279)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 4,224,471		$ 4,515,720		$ (291,249)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (4,227,298)		$ 289,851		$ (4,517,150)				$ -				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (4,353,376)		$ -		$ (4,353,376)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ (497,602)		$ (497,602)		$ -								
	SUBTOTAL		$ (4,853,805)		$ 4,307,970		$ (9,161,775)		$ -		$ -		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 16		$ 8,726		$ (8,711)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,234		$ 3,002		$ (769)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ 2,250	-	$ 11,729	-	$ (9,479)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,347,004)	$ (17,488,579)	3,432,831	$ 86,743,813	(3,401,049)	$ (79,459,238)	-	$ 125,210	(1,378,786)	$ (24,898,364)	8,000	$ 218,318	(1,600)	$ (43,742)
x	Net Congestion Amount		$ 7,938,485		$ 7,938,485				$ -						
y	Net Loss Amount		$ 3,212,276		$ 3,212,276				$ -						
z	Net Congestion and Loss Energy Offset		$ (11,150,761)		$ (11,150,761)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,347,004)**	$ (17,488,579)	3,432,831	$ 86,743,813	(3,401,049)	$ (79,459,238)	-	$ 125,210	(1,378,786)	$ (24,898,364)	8,000	$ 218,318	(1,600)	$ (43,742)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	July 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(1,259,973)	$ (24,437,327)	3,893,051	$ 138,958,303	(3,577,704)	$ (117,279,431)			(1,575,320)	$ (46,116,199)				
5a	Day Ahead Non Asset Energy	(282,263)	$ (11,692,812)	163	$ 4,244	(282,426)	$ (11,697,056)					8,800	$ 366,529	-	$ 0
13a	Real Time Asset Energy	(55,636)	$ 981	64,696	$ 3,450,172	(59,957)	$ (1,939,922)			(60,375)	$ (1,509,270)				
22a	Real Time Non Asset Energy	1,119	$ 2,788,845	1,119	$ 2,788,845	-	$ (0)					-	$ -	-	$ -
	SUBTOTAL	(1,596,752)	$ (33,340,313)	3,959,029	$ 145,201,564	(3,920,086)	$ (130,916,409)	-	$ -	(1,635,695)	$ (47,625,469)	8,800	$ 366,529	-	$ 0
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 1,437		$ 3,500		$ (2,063)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (775,314)		$ (1,675)		$ (773,639)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (773,878)		$ 1,824		$ (775,702)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 744,087		$ 618,817		$ -		$ 125,269				$ 700		
19	Real Time Market Administration (Schedule 17)		$ 58,824		$ 54,062		$ (70)		$ 4,831				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 29,086		$ 29,086		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 111,945		$ 92,980		$ -		$ 18,966				$ 106		
34	Real -Time Schedule 24 Allocation Amount		$ 8,842		$ 8,855		$ (735)				$ 722		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 952,784		$ 803,800		$ (805)		$ 149,066		$ 722		$ 806		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 32,272		$ 33,413		$ (1,141)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (873,678)		$ 1,185,013		$ (2,058,691)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (36,779)		$ -		$ (36,779)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (4,187)		$ -		$ (4,187)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 4,014		$ 4,014		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (878,359)		$ 1,222,440		$ (2,100,798)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 74,320		$ 74,320				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ 3,668				$ 6,688				$ (3,020)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 108,665		$ 108,665				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (225,583)		$ -		$ (28,630)				$ (196,953)				
43	Real Time Price Volatility Make Whole Payment		$ (84,253)		$ 96		$ (68,219)				$ (16,130)				
	SUBTOTAL		$ (123,184)		$ 183,081		$ (90,161)		$ -		$ (216,103)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 188,455		$ 195,452		$ (6,997)				$ -		$ -		
21	Real Time Net Inadvertent Distribution		$ 8,725		$ 225,188		$ (216,463)						$ 263		$ (178)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,236,876		$ 1,697,923		$ (461,047)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,434,056		$ 2,118,563		$ (684,507)		$ -		$ -		$ 263		$ (178)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 4,224,471		$ 4,515,720		$ (291,249)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (4,227,298)		$ 289,851		$ (4,517,150)				$ -				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (1,179,431)		$ -		$ (1,179,431)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 14,501		$ 14,501		$ -								
	SUBTOTAL		$ (1,167,757)		$ 4,820,073		$ (5,987,830)		$ -		$ -		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (32,272)		$ 1,141		$ (33,413)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,437)		$ 2,063		$ (3,500)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ (33,709)	-	$ 3,204	-	$ (36,912)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,596,752)	$ (33,930,359)	3,959,029	$ 154,354,547	(3,920,086)	$ (140,593,123)	-	$ 149,066	(1,635,695)	$ (47,840,849)	8,800	$ 367,597	-	$ (178)
x	Net Congestion Amount		$ 5,231,669		$ 5,231,669				$ -						
y	Net Loss Amount		$ 3,555,982		$ 3,555,982				$ -						
z	Net Congestion and Loss Energy Offset		$ (8,787,651)		$ (8,787,651)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,596,752)**	$ (33,930,359)	3,959,029	$ 154,354,547	(3,920,086)	$ (140,593,123)	-	$ 149,066	(1,635,695)	$ (47,840,849)	8,800	$ 367,597	-	$ (178)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	August 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(1,291,948)	$ (13,014,452)	3,788,271	$ 114,927,822	(3,439,074)	$ (91,123,834)			(1,641,146)	$ (36,818,440)				
5a	Day Ahead Non Asset Energy	(278,621)	$ (9,170,038)	59	$ 1,075	(278,680)	$ (9,171,114)					8,800	$ 309,118	-	$ -
13a	Real Time Asset Energy	(54,484)	$ (994,689)	58,415	$ 1,915,836	(36,854)	$ (1,324,065)			(76,045)	$ (1,586,460)				
22a	Real Time Non Asset Energy	(2,100)	$ (2,654,501)	-	$ (2,440,239)	(2,100)	$ (214,262)					-	$ -	-	$ -
	SUBTOTAL	(1,627,153)	$ (25,833,680)	3,846,746	$ 114,404,494	(3,756,707)	$ (101,833,275)	-	$ -	(1,717,191)	$ (38,404,900)	8,800	$ 309,118	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (644)		$ 1,378		$ (2,022)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,394,179)		$ 4,575		$ (1,398,755)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,394,823)		$ 5,953		$ (1,400,776)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 736,971		$ 602,091		$ -		$ 134,880				$ 708		
19	Real Time Market Administration (Schedule 17)		$ 64,980		$ 59,121		$ (272)		$ 6,131				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 23,341		$ 23,341		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 111,848		$ 91,603		$ -		$ 20,245				$ 110		
34	Real -Time Schedule 24 Allocation Amount		$ 9,864		$ 9,878		$ (942)				$ 929		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 947,004		$ 786,034		$ (1,214)		$ 161,256		$ 929		$ 817		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 17,932		$ 22,546		$ (4,614)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (607,257)		$ 1,835,918		$ (2,443,175)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (91,243)		$ -		$ (91,243)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (95,458)		$ -		$ (95,458)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 88,116		$ 88,116		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (687,911)		$ 1,946,580		$ (2,634,491)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 71,704		$ 71,704				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (76,318)				$ (57,975)				$ (18,343)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 144,420		$ 144,420				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (12,760)		$ -		$ 2,674				$ (15,434)				
43	Real Time Price Volatility Make Whole Payment		$ (229,929)		$ (7)		$ (198,607)				$ (31,315)				
	SUBTOTAL		$ (102,883)		$ 216,117		$ (253,908)		$ -		$ (65,092)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 173,504		$ 173,533		$ (28)				$ -		$ -		
21	Real Time Net Inadvertent Distribution		$ (75,399)		$ 96,847		$ (172,246)						$ 86		$ (166)
23	Real Time Revenue Neutrality Uplift Amount		$ 931,449		$ 1,076,871		$ (145,422)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,029,555		$ 1,347,251		$ (317,696)		$ -		$ -		$ 86		$ (166)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 4,224,471		$ 4,515,720		$ (291,249)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (4,227,298)		$ 289,851		$ (4,517,150)				$ -				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ -		$ -		$ -								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ -		$ -		$ -								
	SUBTOTAL		$ (2,827)		$ 4,805,572		$ (4,808,399)		$ -		$ -		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (17,932)		$ 4,614		$ (22,546)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 644		$ 2,022		$ (1,378)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ (17,288)	-	$ 6,636	-	$ (23,924)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,627,153)	$ (26,062,854)	3,846,746	$ 123,518,638	(3,756,707)	$ (111,273,683)	-	$ 161,256	(1,717,191)	$ (38,469,064)	8,800	$ 310,021	-	$ (166)
x	Net Congestion Amount		$ 9,527,921		$ 9,527,921				$ -						
y	Net Loss Amount		$ 3,565,327		$ 3,565,327				$ -						
z	Net Congestion and Loss Energy Offset		$ (13,093,248)		$ (13,093,248)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,627,153)**	$ (26,062,854)	3,846,746	$ 123,518,638	(3,756,707)	$ (111,273,683)	-	$ 161,256	(1,717,191)	$ (38,469,064)	8,800	$ 310,021	-	$ (166)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	September 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(1,026,969)	$ 17,707,920	3,378,110	$ 101,773,503	(3,236,628)	$ (59,520,496)			(1,168,451)	$ (24,545,087)				
5a	Day Ahead Non Asset Energy	(267,758)	$ (5,994,437)	74	$ 1,838	(267,832)	$ (5,996,274)					8,000	$ 294,644	-	$ -
13a	Real Time Asset Energy	(28,734)	$ (318,330)	45,622	$ 2,022,518	(41,270)	$ (1,631,767)			(33,086)	$ (709,081)				
22a	Real Time Non Asset Energy	1,477	$ 107,414	1,477	$ 107,414	-	$ (0)					-	$ -	-	$ -
	SUBTOTAL	(1,321,984)	$ 11,502,568	3,425,284	$ 103,905,273	(3,545,731)	$ (67,148,538)	-	$ -	(1,201,537)	$ (25,254,168)	8,000	$ 294,644	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (853)		$ 1,023		$ (1,875)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (805,437)		$ (2,138)		$ (803,300)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (806,290)		$ (1,115)		$ (805,175)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 745,518		$ 637,443		$ -		$ 108,076				$ 739		
19	Real Time Market Administration (Schedule 17)		$ 69,203		$ 67,371		$ (1,181)		$ 3,014				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 17,074		$ 17,074		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 117,712		$ 101,854		$ -		$ 15,858				$ 117		
34	Real -Time Schedule 24 Allocation Amount		$ 10,921		$ 10,914		$ (425)				$ 432		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 960,429		$ 834,656		$ (1,606)		$ 126,947		$ 432		$ 856		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 44,054		$ 49,154		$ (5,100)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (7,682,234)		$ 1,944,518		$ (9,626,752)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (282,571)		$ -		$ (282,571)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (154,263)		$ -		$ (154,263)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 149,508		$ 149,508		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (7,925,506)		$ 2,143,180		$ (10,068,686)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 86,314		$ 86,314				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (131,488)				$ (96,590)				$ (34,898)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 70,807		$ 70,807				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (563,053)		$ -		$ (480,821)				$ (82,232)				
43	Real Time Price Volatility Make Whole Payment		$ (39,554)		$ 86		$ (29,649)				$ (9,992)				
	SUBTOTAL		$ (576,976)		$ 157,207		$ (607,060)		$ -		$ (127,122)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 134,368		$ 1,214,976		$ (1,080,609)				$ -		$ (65)		
21	Real Time Net Inadvertent Distribution		$ (78,126)		$ 34,659		$ (112,785)						$ 56		$ (97)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,399,705		$ 1,536,574		$ (136,869)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,455,946		$ 2,786,209		$ (1,330,263)		$ -		$ -		$ (9)		$ (97)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 7,426,682		$ 7,679,462		$ (252,780)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (7,439,189)		$ 252,706		$ (7,691,895)				$ -				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ 5,882,331		$ -		$ 5,882,331								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 100,943		$ 100,943		$ -								
	SUBTOTAL		$ 5,970,767		$ 8,033,111		$ (2,062,344)		$ -		$ -		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (44,054)		$ 5,100		$ (49,154)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 853		$ 1,875		$ (1,023)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ (43,202)	-	$ 6,975	-	$ (50,177)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,321,984)	$ 10,537,737	3,425,284	$ 117,865,496	(3,545,731)	$ (82,073,847)	-	$ 126,947	(1,201,537)	$ (25,380,858)	8,000	$ 295,491	-	$ (97)
x	Net Congestion Amount		$ 33,461,079		$ 33,461,079				$ -						
y	Net Loss Amount		$ 4,071,647		$ 4,071,647				$ -						
z	Net Congestion and Loss Energy Offset		$ (37,532,725)		$ (37,532,725)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,321,984)**	$ 10,537,737	3,425,284	$ 117,865,496	(3,545,731)	$ (82,073,847)	-	$ 126,947	(1,201,537)	$ (25,380,858)	8,000	$ 295,491	-	$ (97)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Northern States Power Company
Electric Operations - State of Minnesota

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

October 2024		NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(561,251)	$ 21,312,079	3,068,047	$ 76,841,551	(2,616,232)	$ (41,854,159)			(1,013,067)	$ (13,675,313)				
5a	Day Ahead Non Asset Energy	(289,717)	$ (7,627,394)	12	$ 235	(289,729)	$ (7,627,629)					7,360	$ 251,245	-	$ -
13a	Real Time Asset Energy	(35,646)	$ (693,629)	35,548	$ 960,305	(21,408)	$ (843,589)			(49,786)	$ (810,345)				
22a	Real Time Non Asset Energy	1	$ 192	1	$ 204	-	$ (12)					-	$ -	-	$ -
	SUBTOTAL	(886,614)	$ 12,991,249	3,103,607	$ 77,802,296	(2,927,369)	$ (50,325,389)	-	$ -	(1,062,852)	$ (14,485,658)	7,360	$ 251,245	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (590)		$ 1,555		$ (2,144)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (775,165)		$ 333		$ (775,498)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (775,755)		$ 1,888		$ (777,643)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 657,536		$ 562,617		$ -		$ 94,919				$ 692		
19	Real Time Market Administration (Schedule 17)		$ 69,217		$ 64,526		$ (149)		$ 4,839				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 14,525		$ 14,525		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 99,292		$ 84,629		$ -		$ 14,663				$ 104		
34	Real -Time Schedule 24 Allocation Amount		$ 10,451		$ 10,451		$ (740)				$ 740		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 851,021		$ 736,748		$ (889)		$ 114,421		$ 740		$ 796		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 38,818		$ 44,711		$ (5,893)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (992,924)		$ 4,177,128		$ (5,170,052)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (101,726)		$ -		$ (101,726)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 202,004		$ 202,004		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (189,775)		$ -		$ (189,775)						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (1,043,603)		$ 4,423,843		$ (5,467,446)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 50,466		$ 50,466				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (87,639)				$ (67,675)				$ (19,964)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 14,929		$ 14,929				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ 28,234		$ -		$ 77,021				$ (48,787)				
43	Real Time Price Volatility Make Whole Payment		$ (34,184)		$ 157,256		$ (163,970)				$ (27,470)				
	SUBTOTAL		$ (28,194)		$ 222,651		$ (154,625)		$ -		$ (96,220)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 124,292		$ 203,982		$ (79,690)				$ -		$ -		
21	Real Time Net Inadvertent Distribution		$ (111,037)		$ 77,797		$ (188,834)						$ 85		$ (222)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,693,229		$ 1,917,911		$ (224,682)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,706,484		$ 2,199,690		$ (493,207)		$ -		$ -		$ 85		$ (222)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 7,426,682		$ 7,679,462		$ (252,780)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (7,439,189)		$ 252,706		$ (7,691,895)				$ -				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (1,194,256)		$ -		$ (1,194,256)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 187,951		$ 187,951		$ -								
	SUBTOTAL		$ (1,018,812)		$ 8,120,119		$ (9,138,931)		$ -		$ -		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (38,818)		$ 5,893		$ (44,711)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 590		$ 2,144		$ (1,555)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ (38,229)	-	$ 8,037	-	$ (46,266)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(886,614)	$ 12,644,162	3,103,607	$ 93,515,273	(2,927,369)	$ (66,404,394)	-	$ 114,421	(1,062,852)	$ (14,581,138)	7,360	$ 252,126	-	$ (222)
x	Net Congestion Amount		$ 18,169,397		$ 18,169,397				$ -						
y	Net Loss Amount		$ 3,700,047		$ 3,700,047				$ -						
z	Net Congestion and Loss Energy Offset		$ (21,869,444)		$ (21,869,444)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(886,614)**	$ 12,644,162	3,103,607	$ 93,515,273	(2,927,369)	$ (66,404,394)	-	$ 114,421	(1,062,852)	$ (14,581,138)	7,360	$ 252,126	-	$ (222)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	November 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(783,500)	$ 3,553,900	3,040,118	$ 77,953,632	(2,933,552)	$ (55,235,650)			(890,066)	$ (19,164,082)				
5a	Day Ahead Non Asset Energy	(156,584)	$ (3,699,537)	21	$ 67	(156,605)	$ (3,699,604)					6,400	$ 199,238	-	$ -
13a	Real Time Asset Energy	(9,473)	$ 31,474	61,168	$ 1,711,931	(12,296)	$ (993,307)			(58,344)	$ (687,150)				
22a	Real Time Non Asset Energy	(449)	$ (15,073)	225	$ 2,333	(674)	$ (17,405)					-	$ -	-	$ -
	SUBTOTAL	(950,006)	$ (129,236)	3,101,531	$ 79,667,962	(3,103,127)	$ (59,945,966)	-	$ -	(948,410)	$ (19,851,232)	6,400	$ 199,238	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 372		$ 1,866		$ (1,494)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (515,596)		$ 5,685		$ (521,281)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (515,224)		$ 7,551		$ (522,775)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 632,602		$ 552,698		$ -		$ 79,903				$ 576		
19	Real Time Market Administration (Schedule 17)		$ 66,577		$ 61,325		$ (45)		$ 5,297				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 12,439		$ 12,439		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 103,918		$ 90,278		$ -		$ 13,640				$ 96		
34	Real -Time Schedule 24 Allocation Amount		$ 10,944		$ 10,951		$ (903)				$ 896		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 826,479		$ 727,691		$ (948)		$ 98,841		$ 896		$ 672		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 7,698		$ 18,304		$ (10,606)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ 315,309		$ 4,672,877		$ (4,357,568)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (119,782)		$ -		$ (119,782)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (27,540)		$ -		$ (27,540)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 27,540		$ 27,540		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ 203,225		$ 4,718,721		$ (4,515,497)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 64,038		$ 64,038				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (197,250)				$ (126,395)				$ (70,855)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 18,574		$ 18,574				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (3,221)		$ 4		$ (3,454)				$ 229				
43	Real Time Price Volatility Make Whole Payment		$ (84,924)		$ 19		$ (60,330)				$ (24,613)				
	SUBTOTAL		$ (202,783)		$ 82,635		$ (190,179)		$ -		$ (95,239)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 122,145		$ 190,537		$ (68,393)				$ -		$ 1		
21	Real Time Net Inadvertent Distribution		$ (52,363)		$ 125,516		$ (177,879)						$ 79		$ (123)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,369,617		$ 1,685,065		$ (315,448)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,439,399		$ 2,001,119		$ (561,720)		$ -		$ -		$ 80		$ (123)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 7,426,682		$ 7,679,462		$ (252,780)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (7,439,189)		$ 252,706		$ (7,691,895)				$ -				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (1,194,256)		$ -		$ (1,194,256)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 187,951		$ 187,951		$ -								
	SUBTOTAL		$ (1,018,812)		$ 8,120,119		$ (9,138,931)		$ -		$ -		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (9,355)		$ 8,886		$ (18,241)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (800)		$ 1,018		$ (1,818)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ (10,155)	-	$ 9,904	-	$ (20,059)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(950,006)	$ 592,894	3,101,531	$ 95,335,701	(3,103,127)	$ (74,896,073)	-	$ 98,841	(948,410)	$ (19,945,575)	6,400	$ 199,990	-	$ (123)
x	Net Congestion Amount		$ 15,060,360		$ 15,060,360				$ -						
y	Net Loss Amount		$ 3,597,543		$ 3,597,543				$ -						
z	Net Congestion and Loss Energy Offset		$ (18,657,903)		$ (18,657,903)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(950,006)**	$ 592,894	3,101,531	$ 95,335,701	(3,103,127)	$ (74,896,073)	-	$ 98,841	(948,410)	$ (19,945,575)	6,400	$ 199,990	-	$ (123)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Docket No. E002/AA-23-153
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	December 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(1,018,192)	$ (10,434,816)	3,503,245	$ 124,543,468	(3,491,604)	$ (103,036,357)			(1,029,834)	$ (31,941,927)				
5a	Day Ahead Non Asset Energy	(158,700)	$ (5,571,417)	29	$ 855	(158,729)	$ (5,572,272)					-	$ -	-	$ -
13a	Real Time Asset Energy	(2,493)	$ 480,984	67,654	$ 2,570,401	41,415	$ 577,712			(111,562)	$ (2,667,129)				
22a	Real Time Non Asset Energy	674	$ 17,405	-	$ -	674	$ 17,405					1	$ 22	-	$ -
	SUBTOTAL	(1,178,711)	$ (15,507,844)	3,570,928	$ 127,114,724	(3,608,244)	$ (108,013,511)	-	$ -	(1,141,396)	$ (34,609,056)	1	$ 22	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 6,439		$ 6,889		$ (450)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,057,933)		$ 14,002		$ (1,071,935)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,051,495)		$ 20,891		$ (1,072,386)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 812,500		$ 710,574		$ -		$ 101,926				$ -		
19	Real Time Market Administration (Schedule 17)		$ 86,284		$ 75,402		$ (338)		$ 11,220				$ 0		
29	Financial Transmission Rights Administration (Schedule 16)		$ 4,640		$ 4,640		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 116,207		$ 100,984		$ -		$ 15,223				$ -		
34	Real -Time Schedule 24 Allocation Amount		$ 12,349		$ 12,404		$ (1,688)				$ 1,633		$ 0		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 1,031,980		$ 904,004		$ (2,026)		$ 128,370		$ 1,633		$ 0		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 29,704		$ 31,960		$ (2,256)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (1,575,777)		$ 3,126,512		$ (4,702,289)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (106,822)		$ -		$ (106,822)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (7,531)		$ -		$ (7,531)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 7,531		$ 7,531		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (1,652,895)		$ 3,166,003		$ (4,818,898)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 70,858		$ 70,858				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (10,962)				$ (6,169)				$ (4,793)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 93,909		$ 93,909				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (205,133)		$ 0		$ (165,719)				$ (39,414)				
43	Real Time Price Volatility Make Whole Payment		$ (144,951)		$ 84		$ (104,261)				$ (40,775)				
	SUBTOTAL		$ (196,281)		$ 164,851		$ (276,149)		$ -		$ (84,982)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 305,517		$ 315,711		$ (10,194)				$ -		$ -		
21	Real Time Net Inadvertent Distribution		$ 142,516		$ 333,885		$ (191,369)						$ 46		$ (28)
23	Real Time Revenue Neutrality Uplift Amount		$ 622,847		$ 1,330,699		$ (707,852)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,070,880		$ 1,980,295		$ (909,415)		$ -		$ -		$ 46		$ (28)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 7,089,351		$ 7,135,214		$ (45,864)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (7,098,113)		$ 45,932		$ (7,144,045)				$ -				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (1,213,949)		$ -		$ (1,213,949)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 132,984		$ 132,984		$ -								
	SUBTOTAL		$ (1,089,728)		$ 7,314,130		$ (8,403,858)		$ -		$ -		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (29,704)		$ 2,256		$ (31,960)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (6,439)		$ 450		$ (6,889)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ (36,143)	-	$ 2,706	-	$ (38,849)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,178,711)	$ (17,431,524)	3,570,928	$ 140,667,603	(3,608,244)	$ (123,535,091)	-	$ 128,370	(1,141,396)	$ (34,692,406)	1	$ 68	-	$ (28)
x	Net Congestion Amount		$ 12,970,001		$ 12,970,001				$ -						
y	Net Loss Amount		$ 5,360,422		$ 5,360,422				$ -						
z	Net Congestion and Loss Energy Offset		$ (18,330,422)		$ (18,330,422)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,178,711)**	$ (17,431,524)	3,570,928	$ 140,667,603	(3,608,244)	$ (123,535,091)	-	$ 128,370	(1,141,396)	$ (34,692,406)	1	$ 68	-	$ (28)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Docket No. E002/AA-23-153
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	January - December 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(11,644,641)	$ 22,323,565	39,676,635	$ 1,138,574,199	(37,399,666)	$ (829,316,964)	-	$ -	(13,921,610)	$ (286,933,670)	-	$ -	-	$ -
5a	Day Ahead Non Asset Energy	(2,584,679)	$ (75,489,323)	584	$ 12,281	(2,585,263)	$ (75,501,604)	-	$ -	-	$ -	81,760	$ 3,047,730	(1,600)	$ (43,463)
13a	Real Time Asset Energy	(305,461)	$ (2,144,419)	662,670	$ 22,088,770	(23,380)	$ (7,707,869)	-	$ -	(944,751)	$ (16,525,321)	-	$ -	-	$ -
22a	Real Time Non Asset Energy	722	$ 244,283	2,822	$ 458,556	(2,100)	$ (214,273)	-	$ -	-	$ -	1	$ 22	-	$ -
	SUBTOTAL	(14,534,059)	$ (55,065,894)	40,342,711	$ 1,161,133,807	(40,010,409)	$ (912,740,711)	-	$ -	(14,866,361)	$ (303,458,991)	81,761	$ 3,047,752	(1,600)	$ (43,463)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
5c	Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
3	Day Ahead Financial Bilateral Transaction Loss	-	$ 25,511	-	$ 41,180	-	$ (15,669)	-	$ -	-	$ -	-	$ -	-	$ -
13c	Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
22c	Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
14	Real Time Distribution Losses	-	$ (10,904,038)	-	$ 492,703	-	$ (11,396,740)	-	$ -	-	$ -	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (10,878,526)	-	$ 533,883	-	$ (11,412,409)	-	$ -	-	$ -	-	$ -	-	$ -
	Virtual Energy														
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)	-	$ 8,225,660	-	$ 7,006,706	-	$ -	-	$ 1,218,954	-	$ -	-	$ 7,208	-	$ -
19	Real Time Market Administration (Schedule 17)	-	$ 832,935	-	$ 753,229	-	$ (4,948)	-	$ 84,655	-	$ -	-	$ 0	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 205,900	-	$ 205,900	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 1,257,832	-	$ 1,071,281	-	$ -	-	$ 186,551	-	$ -	-	$ 1,111	-	$ -
34	Real -Time Schedule 24 Allocation Amount	-	$ 127,367	-	$ 127,904	-	$ (13,319)	-	$ -	-	$ 12,782	-	$ 0	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 10,649,694	-	$ 9,165,020	-	$ (18,267)	-	$ 1,490,159	-	$ 12,782	-	$ 8,319	-	$ -
	Congestion & FTRs														
1b	Day Ahead Congestion	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
5b	Day Ahead Non Asset Congestion	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
13b	Real Time Congestion	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
22b	Real Time Non Asset Congestion	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 322,233	-	$ 398,346	-	$ (76,113)	-	$ -	-	$ -	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (30,612,495)	-	$ 38,710,151	-	$ (69,322,646)	-	$ -	-	$ -	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (1,235,376)	-	$ -	-	$ (1,235,376)	-	$ -	-	$ -	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ (672,102)	-	$ 0	-	$ (672,102)	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (1,768,872)	-	$ 534,714	-	$ (2,303,586)	-	$ -	-	$ -	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 1,856,949	-	$ 2,297,004	-	$ (440,055)	-	$ -	-	$ -	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (32,109,663)	-	$ 41,940,216	-	$ (74,049,879)	-	$ -	-	$ -	-	$ -	-	$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 828,290	-	$ 828,290	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (1,272,171)	-	$ -	-	$ (669,456)	-	$ -	-	$ (602,715)	-	$ -	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 947,523	-	$ 947,523	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (1,607,202)	-	$ 12	-	$ (856,294)	-	$ -	-	$ (750,920)	-	$ -	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (1,907,477)	-	$ 168,774	-	$ (1,532,110)	-	$ -	-	$ (544,141)	-	$ -	-	$ -
	SUBTOTAL	-	$ (3,011,038)	-	$ 1,944,598	-	$ (3,057,859)	-	$ -	-	$ (1,897,776)	-	$ -	-	$ -
	Other Charges														
20	Real Time Miscellaneous	-	$ (1,826,660)	-	$ 3,291,516	-	$ (5,118,176)	-	$ -	-	$ -	-	$ 213	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ (242,014)	-	$ 2,023,352	-	$ (2,265,367)	-	$ -	-	$ -	-	$ 1,729	-	$ (2,016)
23	Real Time Revenue Neutrality Uplift Amount	-	$ 12,748,785	-	$ 17,804,685	-	$ (5,055,900)	-	$ -	-	$ -	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 10,680,111	-	$ 23,119,553	-	$ (12,439,443)	-	$ -	-	$ -	-	$ 1,942	-	$ (2,016)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 67,386,473	-	$ 70,166,515	-	$ (2,780,042)	-	$ -	-	$ -	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (67,549,338)	-	$ 2,711,299	-	$ (70,260,637)	-	$ -	-	$ -	-	$ -	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (13,896,006)	-	$ 0	-	$ (13,896,006)	-	$ -	-	$ -	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 1,280,428	-	$ 1,280,428	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (12,778,442)	-	$ 74,158,242	-	$ (86,936,685)	-	$ -	-	$ -	-	$ -	-	$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (323,377)	-	$ 74,394	-	$ (397,771)	-	$ -	-	$ -	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (26,225)	-	$ 14,907	-	$ (41,132)	-	$ -	-	$ -	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (349,603)	-	$ 89,301	-	$ (438,903)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(14,534,059)	$ (92,863,362)	40,342,711	$ 1,312,084,620	(40,010,409)	$ (1,101,094,156)	-	$ 1,490,159	(14,866,361)	$ (305,343,985)	81,761	$ 3,058,013	(1,600)	$ (45,479)
x	Net Congestion Amount	-	$ 179,471,604	-	$ 179,471,604	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
y	Net Loss Amount	-	$ 47,311,743	-	$ 47,311,743	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (226,783,347)	-	$ (226,783,347)	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(14,534,059)**	$ (92,863,362)	40,342,711	$ 1,312,084,620	(40,010,409)	$ (1,101,094,156)	-	$ 1,490,159	(14,866,361)	$ (305,343,985)	81,761	$ 3,058,013	(1,600)	$ (45,479)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

January 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (121,697)		$ -		$ (24,770)				$ (96,927)				
2 Day-Ahead Spinning Reserve Amount		$ (240,616)		$ -		$ (44,184)				$ (196,433)				
3 Day-Ahead Supplemental Reserve		$ (33,075)		$ -		$ (11,827)				$ (21,248)				
4 Day-Ahead Short Term Reserve Amount		$ (1,024,647)		$ 1		$ 106,389				$ (1,131,037)				
5 Real-Time Regulation Amount (See Note 1)		$ (118,618)		$ 54,986		$ (173,604)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (8,827)		$ 71,494		$ (80,320)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,219		$ 4,085		$ (1,866)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ 43,710		$ 57,810		$ (14,100)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,094)	$ (22,938)	69	$ 450	(1,163)	$ (23,388)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	277,171	$ 10,600,395	563,048	$ 20,394,555	(285,877)	$ (9,794,160)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (52,218)		$ 26,387		$ (75,983)		$ (2,622)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 67,130		$ 67,129		$ 1								
11 Real Time Spinnng Reserve Cost Distribution		$ 96,854		$ 96,858		$ (3)								
12 Real Time Supplemental Reserve Cost Distribution		$ 17,532		$ 17,532		$ (0)								
13 Real Time Short Term Reserve Cost Distribution		$ 632,815		$ 643,582		$ (10,767)								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 67,586		$ 52,268		$ (520)		$ 15,838						
14 Real Time Contignecy Reserve Deployment Failure		$ 1,014		$ 1,014		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ 11		$ 11						$ 1				
MISO ASM CHARGES	276,077	$ 9,906,629	563,117	$ 21,488,161	(287,040)	$ (10,149,105)	-	$ 13,216	-	$ (1,445,644)	-	$ -	-	$ -
x Net Congestion Amount		$ (274,754)		$ (274,754)				$ -						
y Net Loss Amount		$ 22,000		$ 22,000				$ -						
z Net Congestion and Loss Energy Offset		$ 252,754		$ 252,754										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	276,077	$ 9,906,629	563,117	$ 21,488,161	(287,040)	$ (10,149,105)	-	$ 13,216	-	$ (1,445,644)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

February 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (71,355)		$ -		$ (51,828)				$ (19,527)				
2 Day-Ahead Spinning Reserve Amount		$ (120,580)		$ -		$ (37,160)				$ (83,420)				
3 Day-Ahead Supplemental Reserve		$ (21,447)		$ -		$ (11,003)				$ (10,444)				
4 Day-Ahead Short Term Reserve Amount		$ (16,273)		$ 0		$ (222,345)				$ 206,072				
5 Real-Time Regulation Amount (See Note 1)		$ (63,921)		$ 24,000		$ (87,921)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (31,898)		$ 19,875		$ (51,773)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 18,776		$ 18,910		$ (133)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (3,350)		$ 1,746		$ (5,097)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(304)	$ 5,080	94	$ 761	(398)	$ 4,320								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	116,730	$ 3,418,070	468,476	$ 7,270,517	(351,747)	$ (3,852,447)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 11,294		$ 4,268		$ 8,237		$ (1,210)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 108,499		$ 108,719		$ (220)								
11 Real Time Spinnng Reserve Cost Distribution		$ 77,963		$ 77,964		$ (1)								
12 Real Time Supplemental Reserve Cost Distribution		$ 10,275		$ 10,276		$ (0)								
13 Real Time Short Term Reserve Cost Distribution		$ (101,738)		$ (104,171)		$ 2,433								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 12,536		$ 7,601		$ (1,407)		$ 6,341						
14 Real Time Contignecy Reserve Deployment Failure		$ 69		$ 69		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ -						$ -				
MISO ASM CHARGES	116,426	$ 3,232,001	468,571	$ 7,440,534	(352,145)	$ (4,306,344)	-	$ 5,131	-	$ 92,681	-	$ -	-	$ -
x Net Congestion Amount		$ (94,673)		$ (94,673)				$ -						
y Net Loss Amount		$ 5,964		$ 5,964				$ -						
z Net Congestion and Loss Energy Offset		$ 88,709		$ 88,709										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	116,426	$ 3,232,001	468,571	$ 7,440,534	(352,145)	$ (4,306,344)	-	$ 5,131	-	$ 92,681	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

March 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (138,925)		$ -		$ (74,298)				$ (64,627)				
2 Day-Ahead Spinning Reserve Amount		$ (101,258)		$ -		$ (49,284)				$ (51,974)				
3 Day-Ahead Supplemental Reserve		$ (15,191)		$ -		$ (8,263)				$ (6,928)				
4 Day-Ahead Short Term Reserve Amount		$ (16,175)		$ 0		$ (4,083)				$ (12,093)				
5 Real-Time Regulation Amount (See Note 1)		$ (68,680)		$ 46,336		$ (115,016)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (16,701)		$ 34,239		$ (50,940)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 41,658		$ 41,948		$ (290)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (3,030)		$ 1,767		$ (4,797)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(355)	$ 6,786	4	$ 6,809	(359)	$ (24)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	147,594	$ (1,148,695)	443,638	$ 2,970,644	(296,044)	$ (4,119,339)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (1,501)		$ 12,072		$ (12,058)		$ (1,515)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 101,141		$ 101,816		$ (676)								
11 Real Time Spinnng Reserve Cost Distribution		$ 98,445		$ 98,445		$ 0								
12 Real Time Supplemental Reserve Cost Distribution		$ 24,119		$ 24,119		$ -								
13 Real Time Short Term Reserve Cost Distribution		$ 56,229		$ 56,632		$ (403)								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 21,742		$ 3,371		$ (372)		$ 18,743						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ -						$ -				
MISO ASM CHARGES	147,239	$ (1,160,038)	443,642	$ 3,398,198	(296,403)	$ (4,439,842)	-	$ 17,228	-	$ (135,622)	-	$ -	-	$ -
x Net Congestion Amount		$ (764,206)		$ (764,206)				$ -						
y Net Loss Amount		$ (10,228)		$ (10,228)				$ -						
z Net Congestion and Loss Energy Offset		$ 774,434		$ 774,434										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	147,239	$ (1,160,038)	443,642	$ 3,398,198	(296,403)	$ (4,439,842)	-	$ 17,228	-	$ (135,622)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

April 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (169,097)		$ -		$ (99,172)				$ (69,925)				
2 Day-Ahead Spinning Reserve Amount		$ (104,454)		$ -		$ (41,519)				$ (62,936)				
3 Day-Ahead Supplemental Reserve		$ (4,486)		$ -		$ (4,588)				$ 102				
4 Day-Ahead Short Term Reserve Amount		$ (33,575)		$ 0		$ (9,473)				$ (24,102)				
5 Real-Time Regulation Amount (See Note 1)		$ (10,595)		$ 74,668		$ (85,263)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (24,007)		$ 29,961		$ (53,968)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (812)		$ 85		$ (897)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (5,193)		$ 7,487		$ (12,680)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(476)	$ 19,270	353	$ 24,082	(829)	$ (4,811)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	76,532	$ (1,934,976)	437,899	$ 1,454,515	(361,367)	$ (3,389,491)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 1,051		$ 17,335		$ (17,123)		$ 839						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 131,616		$ 131,735		$ (119)								
11 Real Time Spinnng Reserve Cost Distribution		$ 102,058		$ 102,098		$ (40)								
12 Real Time Supplemental Reserve Cost Distribution		$ 5,527		$ 5,531		$ (4)								
13 Real Time Short Term Reserve Cost Distribution		$ 97,362		$ 97,668		$ (307)								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 12,823		$ 11,117		$ (9,346)		$ 11,053						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ -						$ -				
MISO ASM CHARGES	76,056	$ (1,917,489)	438,251	$ 1,956,282	(362,195)	$ (3,728,803)	-	$ 11,892	-	$ (156,861)	-	$ -	-	$ -
x Net Congestion Amount		$ (1,078,078)		$ (1,078,078)				$ -						
y Net Loss Amount		$ 6,922		$ 6,922				$ -						
z Net Congestion and Loss Energy Offset		$ 1,071,156		$ 1,071,156										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	76,056	$ (1,917,489)	438,251	$ 1,956,282	(362,195)	$ (3,728,803)	-	$ 11,892	-	$ (156,861)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

May 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (314,863)		$ -		$ (106,909)				$ (207,954)				
2 Day-Ahead Spinning Reserve Amount		$ (202,749)		$ -		$ (25,830)				$ (176,919)				
3 Day-Ahead Supplemental Reserve		$ (17,291)		$ -		$ (11,924)				$ (5,367)				
4 Day-Ahead Short Term Reserve Amount		$ (83,207)		$ 1		$ 18,695				$ (101,903)				
5 Real-Time Regulation Amount (See Note 1)		$ (64,333)		$ 111,294		$ (175,627)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (63,159)		$ 51,398		$ (114,557)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 1,188		$ 1,768		$ (579)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ 284		$ 29,356		$ (29,072)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(844)	$ 25,957	378	$ 30,755	(1,222)	$ (4,798)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	176,452	$ 3,403,210	530,823	$ 8,231,560	(354,371)	$ (4,828,350)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 5,167		$ 29,904		$ (24,703)		$ (33)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 120,934		$ 120,902		$ 32								
11 Real Time Spinnng Reserve Cost Distribution		$ 176,720		$ 176,691		$ 29								
12 Real Time Supplemental Reserve Cost Distribution		$ 18,227		$ 18,225		$ 3								
13 Real Time Short Term Reserve Cost Distribution		$ 206,205		$ 208,658		$ (2,453)								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 61,785		$ 22,366		$ (4,966)		$ 44,385						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ -						$ -				
MISO ASM CHARGES	175,608	$ 3,274,076	531,201	$ 9,032,876	(355,593)	$ (5,311,008)	-	$ 44,352	-	$ (492,144)	-	$ -	-	$ -
x Net Congestion Amount		$ 239,383		$ 239,383				$ -						
y Net Loss Amount		$ 122,975		$ 122,975				$ -						
z Net Congestion and Loss Energy Offset		$ (362,358)		$ (362,358)										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	175,608	$ 3,274,076	531,201	$ 9,032,876	(355,593)	$ (5,311,008)	-	$ 44,352	-	$ (492,144)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

June 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (331,628)		$ -		$ (55,357)				$ (276,270)				
2 Day-Ahead Spinning Reserve Amount		$ (167,400)		$ -		$ 36,080				$ (203,480)				
3 Day-Ahead Supplemental Reserve		$ (20,434)		$ -		$ (11,551)				$ (8,883)				
4 Day-Ahead Short Term Reserve Amount		$ (74,909)		$ 1		$ (12,920)				$ (61,991)				
5 Real-Time Regulation Amount (See Note 1)		$ (114,663)		$ 105,018		$ (219,681)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (131,488)		$ 27,006		$ (158,494)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 7,475		$ 8,419		$ (944)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ 757		$ 11,455		$ (10,698)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(987)	$ (40,648)	852	$ 404	(1,839)	$ (41,052)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	181,370	$ 3,080,709	516,420	$ 7,740,307	(335,050)	$ (4,659,598)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (4,092)		$ 20,796		$ (26,669)		$ 1,780						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 162,214		$ 162,292		$ (78)								
11 Real Time Spinnng Reserve Cost Distribution		$ 105,145		$ 105,148		$ (3)								
12 Real Time Supplemental Reserve Cost Distribution		$ 10,406		$ 10,405		$ 1								
13 Real Time Short Term Reserve Cost Distribution		$ 80,561		$ 82,128		$ (1,567)								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 95,207		$ 57,154		$ (0)		$ 38,053						
14 Real Time Contignecy Reserve Deployment Failure		$ 20,497		$ 20,091		$ -				$ 406				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ -						$ -				
MISO ASM CHARGES	180,383	$ 2,677,709	517,272	$ 8,350,625	(336,889)	$ (5,162,531)	-	$ 39,833	-	$ (550,218)	-	$ -	-	$ -
x Net Congestion Amount		$ (723,860)		$ (723,860)				$ -						
y Net Loss Amount		$ (101,726)		$ (101,726)				$ -						
z Net Congestion and Loss Energy Offset		$ 825,586		$ 825,586										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	180,383	$ 2,677,709	517,272	$ 8,350,625	(336,889)	$ (5,162,531)	-	$ 39,833	-	$ (550,218)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

July 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (484,992)		$ -		$ (127,980)				$ (357,012)				
2 Day-Ahead Spinning Reserve Amount		$ (147,766)		$ -		$ (90,426)				$ (57,340)				
3 Day-Ahead Supplemental Reserve		$ (36,329)		$ -		$ (33,586)				$ (2,743)				
4 Day-Ahead Short Term Reserve Amount		$ (335,621)		$ 1		$ (81,469)				$ (254,153)				
5 Real-Time Regulation Amount (See Note 1)		$ (186,908)		$ 160,543		$ (347,451)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ 34,934		$ 86,943		$ (52,009)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 12,550		$ 14,130		$ (1,581)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ 44,626		$ 73,384		$ (28,758)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(683)	$ (3,947)	6	$ 79	(690)	$ (4,027)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	240,799	$ 6,285,322	483,145	$ 12,388,476	(242,346)	$ (6,103,153)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 19,443		$ 39,593		$ (35,377)		$ 15,227						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 209,105		$ 209,393		$ (288)								
11 Real Time Spinnng Reserve Cost Distribution		$ 165,663		$ 165,777		$ (114)								
12 Real Time Supplemental Reserve Cost Distribution		$ 66,030		$ 66,037		$ (6)								
13 Real Time Short Term Reserve Cost Distribution		$ 681,697		$ 701,063		$ (19,367)								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 95,636		$ 43,255		$ 34		$ 52,348						
14 Real Time Contignecy Reserve Deployment Failure		$ (17,935)		$ (17,935)		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ -						$ -				
MISO ASM CHARGES	240,116	$ 6,401,507	483,151	$ 13,930,739	(243,035)	$ (6,925,558)	-	$ 67,574	-	$ (671,248)	-	$ -	-	$ -
x Net Congestion Amount		$ (249,855)		$ (249,855)				$ -						
y Net Loss Amount		$ (77,217)		$ (77,217)				$ -						
z Net Congestion and Loss Energy Offset		$ 327,072		$ 327,072										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	240,116	$ 6,401,507	483,151	$ 13,930,739	(243,035)	$ (6,925,558)	-	$ 67,574	-	$ (671,248)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

August 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (564,435)		$ -		$ (102,790)				$ (461,645)				
2 Day-Ahead Spinning Reserve Amount		$ (145,346)		$ -		$ (75,846)				$ (69,500)				
3 Day-Ahead Supplemental Reserve		$ (23,253)		$ -		$ (14,048)				$ (9,205)				
4 Day-Ahead Short Term Reserve Amount		$ (278,985)		$ 1		$ 7,772				$ (286,758)				
5 Real-Time Regulation Amount (See Note 1)		$ (224,165)		$ 158,364		$ (382,529)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (20,682)		$ 27,165		$ (47,847)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 1,652		$ 6,139		$ (4,487)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (14,795)		$ 74,516		$ (89,310)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(976)	$ (15,054)	1,518	$ 57	(2,494)	$ (15,111)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	279,277	$ 6,435,567	581,323	$ 11,372,465	(302,046)	$ (4,936,898)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 43,645		$ 56,256		$ (45,049)		$ 32,438						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 151,576		$ 152,056		$ (480)								
11 Real Time Spinnng Reserve Cost Distribution		$ 76,190		$ 76,195		$ (5)								
12 Real Time Supplemental Reserve Cost Distribution		$ 33,118		$ 33,119		$ (1)								
13 Real Time Short Term Reserve Cost Distribution		$ 236,596		$ 264,110		$ (27,513)								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 127,441		$ 40,062		$ (221)		$ 87,600						
14 Real Time Contignecy Reserve Deployment Failure		$ 3,563		$ 3,563		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ -						$ -				
MISO ASM CHARGES	278,301	$ 5,822,634	582,841	$ 12,264,069	(304,540)	$ (5,734,364)	-	$ 120,038	-	$ (827,108)	-	$ -	-	$ -
x Net Congestion Amount		$ 12,646		$ 12,646				$ -						
y Net Loss Amount		$ (140,445)		$ (140,445)				$ -						
z Net Congestion and Loss Energy Offset		$ 127,799		$ 127,799										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	278,301	$ 5,822,634	582,841	$ 12,264,069	(304,540)	$ (5,734,364)	-	$ 120,038	-	$ (827,108)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

September 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (472,103)		$ -		$ (73,265)				$ (398,838)				
2 Day-Ahead Spinning Reserve Amount		$ (133,576)		$ -		$ (75,006)				$ (58,571)				
3 Day-Ahead Supplemental Reserve		$ (19,855)		$ -		$ (15,987)				$ (3,868)				
4 Day-Ahead Short Term Reserve Amount		$ (63,571)		$ 1		$ (38,115)				$ (25,456)				
5 Real-Time Regulation Amount (See Note 1)		$ (194,399)		$ 155,529		$ (349,928)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (1,603)		$ 53,209		$ (54,813)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (296)		$ 2,993		$ (3,290)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ 5,435		$ 28,739		$ (23,304)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,056)	$ (22,372)	96	$ 2,178	(1,152)	$ (24,550)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	330,574	$ 11,889	570,856	$ 4,003,486	(240,282)	$ (3,991,597)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (1,944)		$ 34,893		$ (44,039)		$ 7,202						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 226,698		$ 227,759		$ (1,061)								
11 Real Time Spinnng Reserve Cost Distribution		$ 133,475		$ 133,505		$ (30)								
12 Real Time Supplemental Reserve Cost Distribution		$ 19,757		$ 19,845		$ (88)								
13 Real Time Short Term Reserve Cost Distribution		$ 618,645		$ 621,033		$ (2,388)								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 111,309		$ 43,778		$ (5,201)		$ 72,732						
14 Real Time Contignecy Reserve Deployment Failure		$ 893		$ 893		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ 9,759		$ 9,759						$ -				
MISO ASM CHARGES	329,518	$ 228,140	570,952	$ 5,337,601	(241,434)	$ (4,702,663)	-	$ 79,934	-	$ (486,732)	-	$ -	-	$ -
x Net Congestion Amount		$ (1,884,370)		$ (1,884,370)				$ -						
y Net Loss Amount		$ (128,789)		$ (128,789)				$ -						
z Net Congestion and Loss Energy Offset		$ 2,013,159		$ 2,013,159										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	329,518	$ 228,140	570,952	$ 5,337,601	(241,434)	$ (4,702,663)	-	$ 79,934	-	$ (486,732)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

October 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (579,930)		$ -		$ (118,529)				$ (461,401)				
2 Day-Ahead Spinning Reserve Amount		$ (110,464)		$ -		$ (49,311)				$ (61,153)				
3 Day-Ahead Supplemental Reserve		$ (16,686)		$ -		$ (11,185)				$ (5,501)				
4 Day-Ahead Short Term Reserve Amount		$ (41,476)		$ 1		$ 1,124				$ (42,602)				
5 Real-Time Regulation Amount (See Note 1)		$ (199,352)		$ 178,711		$ (378,063)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (24,501)		$ 28,549		$ (53,050)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,407		$ 2,569		$ (162)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (896)		$ 3,320		$ (4,217)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(415)	$ 2,004	18	$ 4,729	(433)	$ (2,725)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	159,995	$ 1,534,190	448,311	$ 5,837,007	(288,316)	$ (4,302,817)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 24,255		$ 67,077		$ (65,814)		$ 22,992						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 268,712		$ 271,982		$ (3,271)								
11 Real Time Spinnng Reserve Cost Distribution		$ 177,194		$ 177,266		$ (72)								
12 Real Time Supplemental Reserve Cost Distribution		$ 32,064		$ 32,102		$ (38)								
13 Real Time Short Term Reserve Cost Distribution		$ 102,731		$ 104,307		$ (1,576)								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 89,959		$ 41,190		$ (15)		$ 48,783						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ (4)		$ -				$ 4				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ (4,480)						$ 4,480				
MISO ASM CHARGES	159,580	$ 1,260,211	448,328	$ 6,744,329	(288,749)	$ (4,989,721)	-	$ 71,775	-	$ (566,172)	-	$ -	-	$ -
x Net Congestion Amount		$ (593,668)		$ (593,668)				$ -						
y Net Loss Amount		$ (22,275)		$ (22,275)				$ -						
z Net Congestion and Loss Energy Offset		$ 615,943		$ 615,943										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	159,580	$ 1,260,211	448,328	$ 6,744,329	(288,749)	$ (4,989,721)	-	$ 71,775	-	$ (566,172)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

November 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (526,839)		$ -		$ 119,575				$ (646,415)				
2 Day-Ahead Spinning Reserve Amount		$ (142,719)		$ -		$ (60,817)				$ (81,902)				
3 Day-Ahead Supplemental Reserve		$ (10,679)		$ -		$ (7,376)				$ (3,303)				
4 Day-Ahead Short Term Reserve Amount		$ (18,381)		$ 1		$ (7,342)				$ (11,039)				
5 Real-Time Regulation Amount (See Note 1)		$ (373,069)		$ 130,565		$ (503,634)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (20,514)		$ 33,104		$ (53,618)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (167)		$ 1,560		$ (1,727)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (2,680)		$ 1,481		$ (4,161)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(393)	$ 162	24	$ 2,226	(418)	$ (2,064)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	127,629	$ 1,543,836	420,146	$ 5,746,825	(292,518)	$ (4,202,989)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (43,032)		$ 68,306		$ (86,191)		$ (25,147)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 258,434		$ 258,643		$ (209)								
11 Real Time Spinnng Reserve Cost Distribution		$ 139,078		$ 139,171		$ (93)								
12 Real Time Supplemental Reserve Cost Distribution		$ 14,427		$ 14,471		$ (44)								
13 Real Time Short Term Reserve Cost Distribution		$ 23,781		$ 24,554		$ (773)								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 75,957		$ 35,008		$ (189)		$ 41,138						
14 Real Time Contignecy Reserve Deployment Failure		$ 2,893		$ 2,893		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ -						$ -				
MISO ASM CHARGES	127,235	$ 920,487	420,170	$ 6,458,807	(292,935)	$ (4,811,653)	-	$ 15,992	-	$ (742,659)	-	$ -	-	$ -
x Net Congestion Amount		$ (376,676)		$ (376,676)				$ -						
y Net Loss Amount		$ 49,526		$ 49,526				$ -						
z Net Congestion and Loss Energy Offset		$ 327,150		$ 327,150										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	127,235	$ 920,487	420,170	$ 6,458,807	(292,935)	$ (4,811,653)	-	$ 15,992	-	$ (742,659)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

December 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (186,589)		$ -		$ 60,968				$ (247,557)				
2 Day-Ahead Spinning Reserve Amount		$ (129,478)		$ -		$ (35,626)				$ (93,852)				
3 Day-Ahead Supplemental Reserve		$ (14,691)		$ -		$ (6,789)				$ (7,902)				
4 Day-Ahead Short Term Reserve Amount		$ (45,324)		$ 1		$ 36,041				$ (81,366)				
5 Real-Time Regulation Amount (See Note 1)		$ (338,603)		$ 30,786		$ (369,389)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (21,637)		$ 31,155		$ (52,792)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 247		$ 2,197		$ (1,950)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (28,294)		$ 6,814		$ (35,108)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(731)	$ (17,310)	12	$ 133	(744)	$ (17,443)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	327,283	$ 10,597,329	588,719	$ 19,484,476	(261,437)	$ (8,887,147)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 19,461		$ 31,789		$ (18,745)		$ 6,417						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 260,101		$ 259,969		$ 132								
11 Real Time Spinnng Reserve Cost Distribution		$ 146,913		$ 146,873		$ 40								
12 Real Time Supplemental Reserve Cost Distribution		$ 21,088		$ 21,085		$ 4								
13 Real Time Short Term Reserve Cost Distribution		$ 129,834		$ 165,153		$ (35,318)								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 40,489		$ 18,337		$ (2)		$ 22,154						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ -						$ -				
MISO ASM CHARGES	326,552	$ 10,433,537	588,732	$ 20,198,768	(262,180)	$ (9,363,124)	-	$ 28,570	-	$ (430,677)	-	$ -	-	$ -
x Net Congestion Amount		$ 139,519		$ 139,519				$ -						
y Net Loss Amount		$ 3,527		$ 3,527				$ -						
z Net Congestion and Loss Energy Offset		$ (143,046)		$ (143,046)										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	326,552	$ 10,433,537	588,732	$ 20,198,768	(262,180)	$ (9,363,124)	-	$ 28,570	-	$ (430,677)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

January - December 2024	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
Procurement Charges														
1 Day-Ahead Regulation Amount	-	$ (3,962,453)	-	$ -	-	$ (654,356)	-	$ -	-	$ (3,308,097)	-	$ -	-	$ -
2 Day-Ahead Spinning Reserve Amount	-	$ (1,746,406)	-	$ -	-	$ (548,928)	-	$ -	-	$ (1,197,478)	-	$ -	-	$ -
3 Day-Ahead Supplemental Reserve	-	$ (233,419)	-	$ -	-	$ (148,127)	-	$ -	-	$ (85,292)	-	$ -	-	$ -
4 Day-Ahead Short Term Reserve Amount	-	$ (2,032,147)	-	$ 8	-	$ (205,726)	-	$ -	-	$ (1,826,428)	-	$ -	-	$ -
5 Real-Time Regulation Amount (See Note 1)	-	$ (1,957,308)	-	$ 1,230,799	-	$ (3,188,107)	-	$ -	-	$ -	-	$ -	-	$ -
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (330,083)	-	$ 494,097	-	$ (824,180)	-	$ -	-	$ -	-	$ -	-	$ -
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 86,896	-	$ 104,804	-	$ (17,907)	-	$ -	-	$ -	-	$ -	-	$ -
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ 36,574	-	$ 297,875	-	$ (261,301)	-	$ -	-	$ -	-	$ -	-	$ -
Resource Energy Charges	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
7a Real Time Excessive Energy Amount	(8,314)	$ (63,011)	3,425	$ 72,663	(11,739)	$ (135,674)	-	$ -	-	$ -	-	$ -	-	$ -
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
8a Real Time Non Excessive Energy Amount	2,441,405	$ 43,826,847	6,052,804	$ 106,894,833	(3,611,398)	$ (63,067,987)	-	$ -	-	$ -	-	$ -	-	$ -
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
9 Real Time Net Regulation Adjustment Amount	-	$ 21,530	-	$ 408,676	-	$ (443,515)	-	$ 56,368	-	$ -	-	$ -	-	$ -
Cost Distribution Charges	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 2,066,161	-	$ 2,072,396	-	$ (6,235)	-	$ -	-	$ -	-	$ -	-	$ -
11 Real Time Spinning Reserve Cost Distribution	-	$ 1,495,698	-	$ 1,495,991	-	$ (293)	-	$ -	-	$ -	-	$ -	-	$ -
12 Real Time Supplemental Reserve Cost Distribution	-	$ 272,572	-	$ 272,746	-	$ (174)	-	$ -	-	$ -	-	$ -	-	$ -
13 Real Time Short Term Reserve Cost Distribution	-	$ 2,764,719	-	$ 2,864,719	-	$ (99,999)	-	$ -	-	$ -	-	$ -	-	$ -
Penalty Charges	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
13 Real Time Excessive/Deficient Energy Deployment	-	$ 812,470	-	$ 375,507	-	$ (22,205)	-	$ 459,168	-	$ -	-	$ -	-	$ -
14 Real Time Contingency Reserve Deployment Failure	-	$ 10,995	-	$ 10,585	-	$ -	-	$ -	-	$ 410	-	$ -	-	$ -
15 Real Time Short Term Reserve Deployment Failure	-	$ 9,770	-	$ 5,290	-	$ -	-	$ -	-	$ 4,481	-	$ -	-	$ -
MISO ASM CHARGES	2,433,091	$ 41,079,405	6,056,229	$ 116,600,989	(3,623,137)	$ (69,624,716)	-	$ 515,536	-	$ (6,412,405)	-	$ -	-	$ -
x Net Congestion Amount	-	$ (5,648,591)	-	$ (5,648,591)	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
y Net Loss Amount	-	$ (269,766)	-	$ (269,766)	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
z Net Congestion and Loss Energy Offset	-	$ 5,918,357	-	$ 5,918,357	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	2,433,091	$ 41,079,405	6,056,229	$ 116,600,989	(3,623,137)	$ (69,624,716)	-	$ 515,536	-	$ (6,412,405)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
1/1/2024	1,805,520	1,835,040	29,520	1.61%	0	86	-106	6,967	1,313	828	28,712
1/2/2024	2,011,680	2,046,580	34,900	1.71%	0	682	-282	7,523	999	852	33,648
1/3/2024	3,458,570	3,446,260	-12,310	-0.36%	0	1,215	-941	8,722	977	970	(13,554)
1/4/2024	4,181,770	4,161,350	-20,420	-0.49%	803	1,783	4,865	9,318	1,815	1,113	(28,983)
1/5/2024	4,049,910	4,021,890	-28,020	-0.70%	0	956	354	10,046	2,149	1,220	(30,549)
1/6/2024	3,089,350	3,108,580	19,230	0.62%	0	1,380	-78	8,364	1,293	966	16,962
1/7/2024	2,311,040	2,335,880	24,840	1.06%	0	427	-57	6,963	1,236	820	23,651
1/8/2024	1,263,200	1,293,020	29,820	2.31%	0	426	-310	5,613	1,406	702	29,002
1/9/2024	1,545,230	1,580,240	35,010	2.22%	0	1,176	-101	7,034	1,045	808	33,127
1/10/2024	2,952,120	2,952,360	240	0.01%	0	1,304	-184	7,614	1,181	880	(1,760)
1/11/2024	2,276,250	2,286,660	10,410	0.46%	0	1,032	62	8,023	1,309	933	8,384
1/12/2024	1,645,390	1,687,600	42,210	2.50%	0	362	-7	7,796	1,397	919	40,936
1/13/2024	1,241,660	1,243,850	2,190	0.18%	0	3,598	-13,579	7,189	1,674	886	11,286
1/14/2024	1,900,600	1,876,680	-23,920	-1.27%	0	1,161	-2,853	7,940	1,750	969	(23,198)
1/15/2024	2,098,250	2,071,210	-27,040	-1.31%	0	1,384	-8,690	8,716	1,832	1,055	(20,789)
1/16/2024	1,829,070	1,836,790	7,720	0.42%	0	5,644	-10,301	8,575	1,017	959	11,418
1/17/2024	2,762,390	2,775,140	12,750	0.46%	0	25,600	-11,333	6,831	1,209	804	(2,321)
1/18/2024	2,252,470	2,265,270	12,800	0.57%	0	3,845	1,044	7,479	1,122	860	7,051
1/19/2024	2,265,440	2,306,490	41,050	1.78%	0	324	-236	8,501	1,313	981	39,981
1/20/2024	3,523,580	3,565,550	41,970	1.18%	211	1,360	-334	8,419	1,143	956	39,777
1/21/2024	1,566,890	1,580,420	13,530	0.86%	0	300	2	7,267	1,144	841	12,387
1/22/2024	2,166,000	2,176,290	10,290	0.47%	0	352	350	7,201	1,346	855	8,733
1/23/2024	4,845,610	4,888,790	43,180	0.88%	0	709	1,249	7,848	1,144	899	40,323
1/24/2024	3,640,670	3,641,710	1,040	0.03%	0	262	-510	7,506	1,265	877	411
1/25/2024	2,901,000	2,901,390	390	0.01%	0	212	211	6,729	597	733	(765)
1/26/2024	3,235,460	3,238,660	3,200	0.10%	0	1,011	-319	7,056	803	786	1,722
1/27/2024	2,710,760	2,715,190	4,430	0.16%	0	518	-693	7,085	1,050	813	3,791
1/28/2024	2,284,590	2,287,200	2,610	0.11%	0	582	-36	7,447	1,368	881	1,183
1/29/2024	1,864,040	1,867,230	3,190	0.17%	0	392	-1,524	7,863	1,526	939	3,383
1/30/2024	2,165,510	2,161,720	-3,790	-0.18%	0	604	62	8,127	1,709	984	(5,440)
1/31/2024	2,561,480	2,563,030	1,550	0.06%	0	17	5	9,443	1,404	1,085	443
2/1/2024	1,975,520	1,971,290	-4,230	-0.21%	0	118	123	15,063	2,824	1,789	(6,259)
2/2/2024	804,190	851,340	47,150	5.54%	0	8	16	9,267	1,461	1,073	46,053
2/3/2024	695,140	790,050	94,910	12.01%	0	30	360	7,797	1,307	910	93,610
2/4/2024	1,624,040	1,622,010	-2,030	-0.13%	0	510	185	12,423	1,810	1,423	(4,148)
2/5/2024	1,889,870	1,879,650	-10,220	-0.54%	0	474	202	14,250	1,655	1,591	(12,487)
2/6/2024	1,590,420	1,590,470	50	0.00%	0	210	615	15,476	2,357	1,783	(2,558)
2/7/2024	879,750	907,450	27,700	3.05%	0	207	46	10,734	1,726	1,246	26,200
2/8/2024	852,790	890,580	37,790	4.24%	0	334	-33	11,020	1,704	1,272	36,216
2/9/2024	1,013,020	1,040,890	27,870	2.68%	0	458	-14	11,419	3,308	1,473	25,953
2/10/2024	1,274,940	1,275,660	720	0.06%	0	640	-62	10,531	1,563	1,209	(1,068)
2/11/2024	1,630,830	1,622,220	-8,610	-0.53%	0	1,214	-20	12,938	2,320	1,526	(11,330)
2/12/2024	1,637,430	1,630,320	-7,110	-0.44%	0	215	-1	12,696	2,119	1,481	(8,805)
2/13/2024	2,305,140	2,292,850	-12,290	-0.54%	0	972	-121	12,048	2,277	1,433	(14,574)
2/14/2024	2,294,860	2,289,700	-5,160	-0.23%	0	398	-155	12,449	3,188	1,564	(6,966)
2/15/2024	1,478,630	1,472,460	-6,170	-0.42%	69	146	-41	12,595	2,350	1,495	(7,839)
2/16/2024	1,318,760	1,318,740	-20	0.00%	0	14	125	12,037	1,574	1,361	(1,520)
2/17/2024	845,100	861,300	16,200	1.88%	0	184	107	10,857	1,301	1,216	14,693
2/18/2024	1,692,040	1,685,890	-6,150	-0.36%	0	187	-35	12,905	1,758	1,466	(7,769)
2/19/2024	1,651,870	1,648,480	-3,390	-0.21%	0	468	-318	13,856	1,560	1,542	(5,081)
2/20/2024	1,682,000	1,674,820	-7,180	-0.43%	0	237	-29	13,038	1,476	1,451	(8,840)
2/21/2024	1,705,620	1,700,540	-5,080	-0.30%	0	97	-16	12,604	1,095	1,370	(6,531)
2/22/2024	1,168,200	1,160,420	-7,780	-0.67%	0	12	266	11,929	1,335	1,326	(9,384)
2/23/2024	1,192,790	1,183,750	-9,040	-0.76%	0	45	-7	11,750	1,656	1,341	(10,419)
2/24/2024	991,090	995,080	3,990	0.40%	0	84	-57	11,461	1,109	1,257	2,706
2/25/2024	1,797,110	1,797,820	710	0.04%	0	382	-335	12,103	1,953	1,406	(743)
2/26/2024	878,520	871,570	-6,950	-0.80%	0	75	0	10,190	1,298	1,149	(8,174)
2/27/2024	929,140	924,360	-4,780	-0.52%	0	30	-4	10,968	2,044	1,301	(6,108)
2/28/2024	1,931,770	1,946,160	14,390	0.74%	0	454	289	14,042	2,720	1,676	11,971
2/29/2024	936,020	932,920	-3,100	-0.33%	0	241	205	11,084	1,757	1,284	(4,830)
3/1/2024	539,830	530,500	-9,330	-1.76%	0	596	-80	5,384	900	628	(10,474)
3/2/2024	635,030	634,590	-440	-0.07%	0	927	-386	5,385	1,287	667	(1,648)
3/3/2024	545,780	602,380	56,600	9.40%	0	349	13	5,747	1,168	691	55,547

Northern States Power Company
Electric Operations – State of Minnesota
MISO – Ancillary Services Market

Docket No. E002/AA-23-153
True-up Report
Part B, Attachment 12

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
3/4/2024	1,161,210	1,153,310	-7,900	-0.68%	0	515	-83	6,765	1,596	836	(9,168)
3/5/2024	2,155,480	2,140,850	-14,630	-0.68%	0	306	-551	8,696	1,467	1,016	(15,401)
3/6/2024	1,660,240	1,657,890	-2,350	-0.14%	0	586	59	9,133	1,274	1,041	(4,036)
3/7/2024	2,163,100	2,151,610	-11,490	-0.53%	0	330	-698	9,102	1,229	1,033	(12,154)
3/8/2024	2,406,240	2,409,680	3,440	0.14%	0	462	-308	9,541	1,131	1,067	2,218
3/9/2024	1,347,540	1,346,110	-1,430	-0.11%	0	260	-90	8,063	1,374	944	(2,543)
3/10/2024	1,378,220	1,387,250	9,030	0.65%	0	1,092	81	8,831	1,236	1,007	6,850
3/11/2024	1,161,190	1,158,190	-3,000	-0.26%	0	54	-292	7,957	1,050	901	(3,663)
3/12/2024	1,424,520	1,419,610	-4,910	-0.35%	0	1,340	-314	8,463	912	938	(6,874)
3/13/2024	1,392,700	1,393,390	690	0.05%	0	1,702	26	8,748	875	962	(2,000)
3/14/2024	1,045,030	1,055,550	10,520	1.00%	0	2,426	-90	8,041	1,276	932	7,252
3/15/2024	932,370	957,000	24,630	2.57%	0	394	-183	7,293	749	804	23,615
3/16/2024	562,460	646,060	83,600	12.94%	0	1,141	-37	6,289	616	691	81,805
3/17/2024	754,690	775,630	20,940	2.70%	0	10	514	7,417	664	808	19,609
3/18/2024	1,266,770	1,266,570	-200	-0.02%	0	4,337	1,907	8,886	835	972	(7,416)
3/19/2024	973,690	976,270	2,580	0.26%	0	487	110	8,317	818	914	1,070
3/20/2024	1,821,910	1,814,770	-7,140	-0.39%	0	498	-300	10,149	1,171	1,132	(8,470)
3/21/2024	2,312,530	2,306,780	-5,750	-0.25%	0	354	71	9,629	921	1,055	(7,230)
3/22/2024	1,360,770	1,354,700	-6,070	-0.45%	0	1,485	3	9,157	1,222	1,038	(8,596)
3/23/2024	1,506,830	1,505,800	-1,030	-0.07%	0	1,030	-181	8,900	829	973	(2,852)
3/24/2024	979,980	971,900	-8,080	-0.83%	0	3	16	8,093	962	905	(9,005)
3/25/2024	1,132,760	1,128,690	-4,070	-0.36%	0	347	114	8,764	1,184	995	(5,526)
3/26/2024	1,295,870	1,288,270	-7,600	-0.59%	0	259	46	9,662	1,678	1,134	(9,039)
3/27/2024	2,117,890	2,108,640	-9,250	-0.44%	0	523	123	9,628	1,243	1,087	(10,983)
3/28/2024	2,674,770	2,671,970	-2,800	-0.10%	0	2,114	-228	8,772	786	956	(5,642)
3/29/2024	1,907,670	1,915,320	7,650	0.40%	0	59	-144	8,521	1,108	963	6,771
3/30/2024	2,034,950	2,039,000	4,050	0.20%	0	169	-848	8,350	683	903	3,826
3/31/2024	1,152,480	1,152,270	-210	-0.02%	0	143	-423	7,004	804	781	(711)
4/1/2024	1,265,380	1,268,760	3,380	0.27%	0	91	4,972	11,321	2,135	1,346	(3,028)
4/2/2024	1,149,730	1,148,940	-790	-0.07%	0	251	-135	11,961	1,431	1,339	(2,246)
4/3/2024	1,156,740	1,147,400	-9,340	-0.81%	0	666	-295	13,056	923	1,398	(11,109)
4/4/2024	1,242,960	1,239,740	-3,220	-0.26%	0	946	-333	12,045	1,502	1,355	(5,187)
4/5/2024	1,340,480	1,334,280	-6,200	-0.46%	0	658	-512	11,711	1,439	1,315	(7,662)
4/6/2024	816,260	809,550	-6,710	-0.83%	0	5	98	11,007	989	1,200	(8,013)
4/7/2024	955,630	954,210	-1,420	-0.15%	0	29	261	11,518	774	1,229	(2,940)
4/8/2024	1,130,470	1,122,120	-8,350	-0.74%	0	1,000	73	10,955	1,729	1,268	(10,691)
4/9/2024	1,315,210	1,313,580	-1,630	-0.12%	0	871	-482	12,387	1,758	1,414	(3,434)
4/10/2024	1,253,390	1,255,450	2,060	0.16%	0	352	726	12,387	1,534	1,392	(410)
4/11/2024	895,730	895,090	-640	-0.07%	0	76	-418	11,338	1,021	1,236	(1,534)
4/12/2024	1,061,680	1,053,690	-7,990	-0.76%	0	726	110	10,578	1,286	1,186	(10,012)
4/13/2024	688,100	691,180	3,080	0.45%	0	635	-106	10,183	1,319	1,150	1,401
4/14/2024	1,147,080	1,153,260	6,180	0.54%	0	3,046	-1,628	11,190	2,396	1,359	3,404
4/15/2024	1,043,960	1,064,090	20,130	1.89%	0	1,255	481	11,310	1,137	1,245	17,149
4/16/2024	888,510	893,550	5,040	0.56%	0	936	1,320	11,080	1,406	1,249	1,535
4/17/2024	1,016,510	1,025,030	8,520	0.83%	0	681	-507	11,477	1,039	1,252	7,095
4/18/2024	1,084,400	1,086,720	2,320	0.21%	0	381	-197	11,438	1,295	1,273	862
4/19/2024	1,059,200	1,051,200	-8,000	-0.76%	0	842	-220	12,168	1,489	1,366	(9,989)
4/20/2024	928,510	921,230	-7,280	-0.79%	0	1,635	-439	10,907	1,279	1,219	(9,694)
4/21/2024	1,018,780	1,011,530	-7,250	-0.72%	0	491	-2,250	11,061	1,096	1,216	(6,707)
4/22/2024	907,320	901,480	-5,840	-0.65%	0	109	757	10,867	1,430	1,230	(7,936)
4/23/2024	845,820	834,530	-11,290	-1.35%	0	1	1	10,459	1,660	1,212	(12,504)
4/24/2024	1,166,910	1,170,010	3,100	0.26%	0	3,832	-79	10,092	1,411	1,150	(1,803)
4/25/2024	606,730	608,370	1,640	0.27%	0	5	3	9,431	652	1,008	624
4/26/2024	789,390	786,930	-2,460	-0.31%	0	647	345	10,481	1,277	1,176	(4,628)
4/27/2024	657,140	662,700	5,560	0.84%	0	461	-188	8,462	1,602	1,006	4,281
4/28/2024	770,370	769,590	-780	-0.10%	0	1,111	245	10,170	1,408	1,158	(3,294)
4/29/2024	1,056,850	1,058,940	2,090	0.20%	0	914	-358	10,594	1,165	1,176	359
4/30/2024	1,104,990	1,093,450	-11,540	-1.06%	0	764	58	11,195	1,520	1,272	(13,633)
5/1/2024	1,291,880	1,302,250	10,370	0.80%	0	0	2,291	-2,742	10,463	1,735	6,344
5/2/2024	1,317,320	1,332,560	15,240	1.14%	0	0	1,254	114	10,485	1,703	12,283
5/3/2024	1,380,430	1,377,010	-3,420	-0.25%	0	0	1,096	-570	10,958	1,365	(5,880)
5/4/2024	1,408,310	1,409,690	1,380	0.10%	0	0	1,338	740	10,473	1,270	(1,228)
5/5/2024	1,362,930	1,372,130	9,200	0.67%	0	0	5,083	355	9,799	1,058	3,059

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
5/6/2024	935,990	957,720	21,730	2.27%	0	0	464	605	10,503	1,383	19,883
5/7/2024	1,065,150	1,081,790	16,640	1.54%	0	0	152	1,263	10,233	1,849	14,639
5/8/2024	1,373,780	1,369,680	-4,100	-0.30%	0	0	5,433	-1,597	9,844	2,342	(11,874)
5/9/2024	1,129,000	1,137,390	8,390	0.74%	0	0	1,310	-557	8,744	1,188	5,893
5/10/2024	1,024,570	1,035,760	11,190	1.08%	0	0	699	-222	8,764	949	9,542
5/11/2024	1,033,180	1,033,700	520	0.05%	0	0	2,456	-241	7,868	1,104	(3,040)
5/12/2024	909,960	912,900	2,940	0.32%	0	0	986	437	8,318	1,383	571
5/13/2024	1,271,020	1,266,150	-4,870	-0.38%	0	0	1,055	-919	9,390	1,191	(7,116)
5/14/2024	1,349,150	1,370,320	21,170	1.54%	0	0	2,464	188	9,424	811	17,894
5/15/2024	1,221,430	1,228,490	7,060	0.57%	0	0	2,717	45	9,902	1,418	2,925
5/16/2024	1,815,270	1,812,000	-3,270	-0.18%	0	0	5,663	3,459	11,950	1,026	(9,960)
5/17/2024	1,399,790	1,406,130	6,340	0.45%	0	0	2,265	-64	12,389	1,559	2,516
5/18/2024	1,174,780	1,180,400	5,620	0.48%	0	0	2,335	387	10,812	1,726	1,559
5/19/2024	1,345,790	1,382,130	36,340	2.63%	0	0	4,963	2,679	10,923	1,405	29,972
5/20/2024	1,627,170	1,632,400	5,230	0.32%	0	0	8,385	1,710	11,203	1,580	(4,735)
5/21/2024	1,347,320	1,367,270	19,950	1.46%	0	0	2,235	584	11,935	2,349	15,366
5/22/2024	1,141,270	1,146,500	5,230	0.46%	0	0	185	-310	10,705	1,765	3,280
5/23/2024	1,247,700	1,262,520	14,820	1.17%	0	0	5,946	-504	11,077	1,430	7,444
5/24/2024	911,260	906,530	-4,730	-0.52%	0	0	494	624	9,553	1,192	(6,416)
5/25/2024	1,124,350	1,118,480	-5,870	-0.52%	0	0	446	-160	10,077	1,429	(7,745)
5/26/2024	1,390,690	1,393,710	3,020	0.22%	0	0	597	-352	10,319	988	1,435
5/27/2024	867,800	868,060	260	0.03%	0	0	20	150	8,537	1,038	(798)
5/28/2024	1,274,340	1,272,530	-1,810	-0.14%	0	0	587	-11	10,305	1,424	(3,821)
5/29/2024	1,623,490	1,613,300	-10,190	-0.63%	0	0	199	278	10,999	1,242	(11,631)
5/30/2024	1,179,680	1,182,780	3,100	0.26%	0	0	39	25	10,413	1,426	1,636
5/31/2024	1,788,990	1,788,890	-100	-0.01%	0	0	747	-344	11,289	1,644	(2,491)
6/1/2024	1,885,310	1,885,350	40	0.00%	0	2,293	-180	9,481	957	1,044	(3,117)
6/2/2024	1,188,490	1,198,690	10,200	0.85%	0	63	11	8,938	1,275	1,021	9,105
6/3/2024	1,901,760	1,912,530	10,770	0.56%	0	4,137	3,601	10,437	1,630	1,207	1,825
6/4/2024	1,721,820	1,728,410	6,590	0.38%	0	4,022	448	11,091	1,689	1,278	842
6/5/2024	965,050	984,800	19,750	2.01%	0	10	38	8,403	1,302	970	18,732
6/6/2024	960,640	999,340	38,700	3.87%	0	180	20	8,526	994	952	37,548
6/7/2024	1,729,840	1,744,040	14,200	0.81%	0	758	15	9,611	1,168	1,078	12,349
6/8/2024	1,808,390	1,808,030	-360	-0.02%	0	632	-128	9,872	1,593	1,146	(2,011)
6/9/2024	1,337,910	1,335,370	-2,540	-0.19%	0	476	13	8,830	1,057	989	(4,017)
6/10/2024	1,877,140	1,881,420	4,280	0.23%	0	377	-173	10,015	1,264	1,128	2,948
6/11/2024	1,521,010	1,559,840	38,830	2.49%	0	2,350	-398	9,901	1,635	1,154	35,725
6/12/2024	1,713,320	1,715,060	1,740	0.10%	0	1,251	-215	10,535	1,711	1,225	(520)
6/13/2024	2,088,830	2,110,490	21,660	1.03%	0	4,119	-531	11,115	1,605	1,272	16,800
6/14/2024	2,143,440	2,151,550	8,110	0.38%	0	3,112	-186	10,724	1,064	1,179	4,006
6/15/2024	807,680	845,300	37,620	4.45%	0	61	113	7,198	1,729	893	36,553
6/16/2024	1,181,480	1,216,750	35,270	2.90%	2,562	1,546	-118	8,155	1,146	930	30,350
6/17/2024	1,603,890	1,608,720	4,830	0.30%	0	595	98	9,782	1,654	1,144	2,994
6/18/2024	1,744,060	1,760,090	16,030	0.91%	0	818	-275	11,013	1,834	1,285	14,202
6/19/2024	2,249,060	2,262,320	13,260	0.59%	0	34,547	-1,906	11,130	888	1,202	(20,583)
6/20/2024	2,350,280	2,368,320	18,040	0.76%	0	778	-732	11,803	1,120	1,292	16,701
6/21/2024	2,108,590	2,132,400	23,810	1.12%	0	1,975	420	11,275	1,303	1,258	20,157
6/22/2024	1,890,680	1,887,790	-2,890	-0.15%	0	965	119	9,975	1,018	1,099	(5,073)
6/23/2024	2,144,080	2,161,180	17,100	0.79%	0	6,291	-2,508	10,777	507	1,128	12,188
6/24/2024	1,801,260	1,816,280	15,020	0.83%	0	5,888	366	11,826	1,220	1,305	7,462
6/25/2024	2,277,440	2,285,460	8,020	0.35%	0	1,722	1,421	11,818	1,379	1,320	3,558
6/26/2024	2,143,060	2,158,150	15,090	0.70%	0	5,545	-1,132	11,632	748	1,238	9,439
6/27/2024	1,979,850	1,971,700	-8,150	-0.41%	0	642	60	11,127	1,248	1,237	(10,090)
6/28/2024	1,732,630	1,794,700	62,070	3.46%	0	1,444	21	10,963	1,201	1,216	59,389
6/29/2024	1,270,110	1,295,420	25,310	1.95%	0	1,026	713	9,271	1,316	1,059	22,512
6/30/2024	1,598,770	1,601,900	3,130	0.20%	0	490	96	8,933	773	971	1,573
7/1/2024	1,163,500	1,215,770	52,270	4.30%	0	362	-94	9,510	1,186	1,070	50,933
7/2/2024	2,017,090	2,071,420	54,330	2.62%	0	3,865	143	11,151	1,224	1,238	49,084
7/3/2024	2,733,180	2,753,640	20,460	0.74%	0	4,367	-574	13,487	1,091	1,458	15,208
7/4/2024	2,587,040	2,612,400	25,360	0.97%	0	3,493	382	12,617	1,480	1,410	20,075
7/5/2024	2,256,450	2,269,080	12,630	0.56%	0	1,824	26	12,189	1,938	1,413	9,367
7/6/2024	2,191,160	2,199,120	7,960	0.36%	0	3,723	821	10,763	563	1,133	2,284
7/7/2024	2,273,130	2,275,870	2,740	0.12%	0	2,864	-82	11,306	613	1,192	(1,234)

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
7/8/2024	2,658,940	2,675,570	16,630	0.62%	0	1,992	5,553	11,979	475	1,245	7,839
7/9/2024	2,704,050	2,716,550	12,500	0.46%	0	1,079	559	12,002	406	1,241	9,622
7/10/2024	2,675,000	2,690,990	15,990	0.59%	0	2,724	-1,504	12,041	847	1,289	13,481
7/11/2024	2,699,520	2,707,460	7,940	0.29%	0	2,582	-1,068	12,174	736	1,291	5,135
7/12/2024	2,824,850	2,828,270	3,420	0.12%	0	2,292	-30	14,013	1,675	1,569	(411)
7/13/2024	2,871,060	2,877,930	6,870	0.24%	0	3,477	1,144	13,827	1,692	1,552	697
7/14/2024	2,970,530	3,005,960	35,430	1.18%	0	1,610	682	13,104	1,223	1,433	31,705
7/15/2024	3,019,190	3,038,410	19,220	0.63%	0	16,387	5,808	14,232	1,442	1,567	(4,542)
7/16/2024	2,970,450	2,987,320	16,870	0.56%	0	4,331	1,013	13,324	1,035	1,436	10,091
7/17/2024	2,393,240	2,420,070	26,830	1.11%	0	2,240	-1,288	12,060	710	1,277	24,601
7/18/2024	2,517,110	2,586,970	69,860	2.70%	0	3,215	-1,031	11,591	545	1,214	66,462
7/19/2024	2,463,710	2,521,670	57,960	2.30%	0	2,423	104	12,308	1,196	1,350	54,082
7/20/2024	2,572,870	2,616,670	43,800	1.67%	0	1,740	-264	11,592	293	1,189	41,135
7/21/2024	2,682,910	2,728,000	45,090	1.65%	0	1,203	431	11,745	370	1,212	42,245
7/22/2024	2,953,490	3,026,010	72,520	2.40%	0	2,422	684	12,566	543	1,311	68,103
7/23/2024	2,849,970	2,911,290	61,320	2.11%	0	3,910	785	12,510	975	1,348	55,277
7/24/2024	2,981,260	3,051,190	69,930	2.29%	0	3,136	224	12,998	1,065	1,406	65,164
7/25/2024	2,833,310	2,845,030	11,720	0.41%	0	2,549	1,361	13,644	1,640	1,528	6,282
7/26/2024	2,157,440	2,196,180	38,740	1.76%	0	2,803	-734	12,268	1,374	1,364	35,306
7/27/2024	2,070,330	2,105,950	35,620	1.69%	0	1,144	-111	12,153	1,088	1,324	33,263
7/28/2024	2,320,990	2,355,420	34,430	1.46%	6,794	3,985	22,012	12,607	1,411	1,402	237
7/29/2024	2,815,960	2,897,100	81,140	2.80%	0	4,340	-869	12,200	697	1,290	76,379
7/30/2024	2,849,620	2,903,710	54,090	1.86%	0	5,253	-806	12,818	1,065	1,388	48,255
7/31/2024	2,838,590	2,900,310	61,720	2.13%	157	7,720	-3,073	12,600	1,301	1,390	55,527
8/1/2024	2,883,690	2,909,520	25,830	0.89%	0	5,177	2,078	13,285	1,383	1,467	17,108
8/2/2024	2,812,780	2,853,890	41,110	1.44%	0	2,596	1,262	12,471	777	1,325	35,927
8/3/2024	2,641,610	2,679,480	37,870	1.41%	0	3,006	2,347	11,943	936	1,288	31,229
8/4/2024	2,515,630	2,522,980	7,350	0.29%	0	3,676	942	11,946	1,577	1,352	1,379
8/5/2024	2,065,790	2,092,080	26,290	1.26%	0	3,507	1,014	11,554	2,488	1,404	20,365
8/6/2024	2,296,190	2,314,140	17,950	0.78%	0	1,361	-888	11,674	1,122	1,280	16,198
8/7/2024	2,043,660	2,060,680	17,020	0.83%	0	4,885	7	10,588	1,206	1,179	10,949
8/8/2024	1,595,610	1,596,470	860	0.05%	0	1,455	-86	10,452	1,201	1,165	(1,674)
8/9/2024	1,539,030	1,537,930	-1,100	-0.07%	0	630	-4	9,620	1,021	1,064	(2,790)
8/10/2024	1,955,660	1,961,710	6,050	0.31%	0	2,478	27	9,979	626	1,061	2,484
8/11/2024	1,958,070	1,967,700	9,630	0.49%	0	1,557	208	9,714	431	1,015	6,850
8/12/2024	2,659,780	2,672,250	12,470	0.47%	0	3,854	4,098	11,838	483	1,232	3,286
8/13/2024	2,648,700	2,652,760	4,060	0.15%	0	2,698	-178	12,651	787	1,344	196
8/14/2024	2,295,310	2,311,810	16,500	0.71%	0	5,380	2,218	12,229	1,702	1,393	7,509
8/15/2024	2,351,230	2,377,620	26,390	1.11%	0	15,384	11,036	11,995	1,502	1,350	(1,380)
8/16/2024	2,181,820	2,202,800	20,980	0.95%	0	3,821	-1,253	12,579	1,688	1,427	16,986
8/17/2024	2,037,860	2,039,600	1,740	0.09%	0	2,700	3	11,338	1,406	1,274	(2,237)
8/18/2024	2,193,060	2,200,910	7,850	0.36%	0	6,928	1,963	10,261	289	1,055	(2,096)
8/19/2024	2,481,580	2,505,910	24,330	0.97%	0	2,471	-1,260	11,187	685	1,187	21,933
8/20/2024	2,429,690	2,438,780	9,090	0.37%	0	1,167	-254	12,145	1,026	1,317	6,860
8/21/2024	2,195,400	2,213,950	18,550	0.84%	0	1,150	-272	12,531	1,466	1,400	16,272
8/22/2024	2,314,230	2,343,080	28,850	1.23%	0	3,569	1,333	13,413	1,321	1,473	22,474
8/23/2024	2,649,320	2,669,710	20,390	0.76%	0	7,292	-839	13,400	1,139	1,454	12,483
8/24/2024	2,263,990	2,294,620	30,630	1.33%	0	2,879	806	12,081	3,090	1,517	25,428
8/25/2024	2,391,500	2,405,900	14,400	0.60%	0	1,649	294	12,039	1,118	1,316	11,142
8/26/2024	2,796,780	2,835,950	39,170	1.38%	0	22,697	-2,187	12,426	1,001	1,343	17,317
8/27/2024	2,823,100	2,841,630	18,530	0.65%	0	2,653	-788	12,438	823	1,326	15,340
8/28/2024	2,800,300	2,838,040	37,740	1.33%	0	8,908	77	12,790	1,750	1,454	27,301
8/29/2024	2,332,960	2,336,720	3,760	0.16%	0	4,627	1,032	13,085	2,507	1,559	(3,458)
8/30/2024	2,821,480	2,828,720	7,240	0.26%	0	6,900	-403	12,787	1,054	1,384	(641)
8/31/2024	2,037,170	2,037,880	710	0.03%	0	3,811	-47	11,955	1,433	1,339	(4,393)
9/1/2024	1,722,490	1,735,660	13,170	0.76%	0	655	-46	11,364	901	1,227	11,335
9/2/2024	1,403,150	1,417,650	14,500	1.02%	0	1,333	60	10,711	1,010	1,172	11,935
9/3/2024	1,529,690	1,543,580	13,890	0.90%	0	1,852	104	12,482	989	1,347	10,586
9/4/2024	1,919,050	1,913,510	-5,540	-0.29%	0	2,810	-708	13,865	1,542	1,541	(9,182)
9/5/2024	2,094,310	2,118,780	24,470	1.15%	893	4,415	2,055	13,772	1,996	1,577	15,530
9/6/2024	1,794,150	1,864,120	69,970	3.75%	0	601	937	11,663	1,056	1,272	67,160
9/7/2024	1,574,410	1,612,210	37,800	2.34%	0	594	-82	9,908	416	1,032	36,256
9/8/2024	1,289,870	1,332,330	42,460	3.19%	0	2,150	-354	10,554	922	1,148	39,516

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
9/9/2024	1,659,970	1,666,040	6,070	0.36%	0	4,354	-77	12,140	1,456	1,360	434
9/10/2024	1,582,440	1,575,180	-7,260	-0.46%	0	3,533	159	12,222	1,754	1,398	(12,349)
9/11/2024	1,834,950	1,833,340	-1,610	-0.09%	0	1,231	-642	11,858	1,251	1,311	(3,509)
9/12/2024	1,734,440	1,737,830	3,390	0.20%	0	1,856	-739	12,216	1,473	1,369	904
9/13/2024	1,886,840	1,891,230	4,390	0.23%	0	2,255	348	13,167	1,296	1,446	341
9/14/2024	2,036,990	2,033,270	-3,720	-0.18%	0	10,348	-160	12,655	883	1,354	(15,262)
9/15/2024	1,650,390	1,640,830	-9,560	-0.58%	0	2,708	1,390	12,235	1,412	1,365	(15,022)
9/16/2024	1,974,000	1,968,640	-5,360	-0.27%	0	5,745	3,273	13,338	1,387	1,472	(15,851)
9/17/2024	1,935,910	1,930,420	-5,490	-0.28%	0	2,063	-872	13,021	1,233	1,425	(8,107)
9/18/2024	1,863,110	1,865,700	2,590	0.14%	0	3,806	-1,821	13,001	1,312	1,431	(827)
9/19/2024	1,963,750	1,964,920	1,170	0.06%	0	2,391	-362	12,873	1,489	1,436	(2,295)
9/20/2024	2,066,640	2,056,750	-9,890	-0.48%	0	1,621	-1,419	11,647	1,833	1,348	(11,440)
9/21/2024	1,496,200	1,493,910	-2,290	-0.15%	0	3,974	-661	11,308	2,183	1,349	(6,952)
9/22/2024	1,423,360	1,426,080	2,720	0.19%	0	6,282	1,477	9,545	1,240	1,079	(6,117)
9/23/2024	1,952,270	1,953,670	1,400	0.07%	0	4,362	3,125	11,625	1,698	1,332	(7,419)
9/24/2024	1,983,270	1,982,930	-340	-0.02%	0	5,000	10,167	10,964	1,043	1,201	(16,707)
9/25/2024	2,060,620	2,060,210	-410	-0.02%	0	3,346	-2,278	10,546	823	1,137	(2,614)
9/26/2024	1,841,740	1,845,980	4,240	0.23%	0	9,123	5,190	11,946	1,572	1,352	(11,425)
9/27/2024	1,884,160	1,884,200	40	0.00%	0	2,654	-3,080	10,913	1,445	1,236	(770)
9/28/2024	1,498,820	1,502,800	3,980	0.26%	0	2,290	-908	8,839	861	970	1,628
9/29/2024	1,304,990	1,323,920	18,930	1.43%	0	3,916	3,661	8,814	1,438	1,025	10,328
9/30/2024	1,189,120	1,208,460	19,340	1.60%	0	8,755	-1,893	10,942	2,726	1,367	11,111
10/1/2024	1,198,360	1,223,370	25,010	2.04%	0	1,972	925	9,227	1,564	1,079	21,034
10/2/2024	1,112,090	1,118,290	6,200	0.55%	0	3,373	13,138	9,624	1,944	1,157	(11,467)
10/3/2024	1,046,230	1,072,060	25,830	2.41%	0	1,774	6,106	8,553	1,223	978	16,972
10/4/2024	957,050	989,640	32,590	3.29%	0	1,089	-473	7,475	1,166	864	31,110
10/5/2024	528,370	580,490	52,120	8.98%	0	0	13	7,557	759	832	51,275
10/6/2024	742,500	774,950	32,450	4.19%	0	4,060	-742	7,701	809	851	28,281
10/7/2024	1,366,220	1,346,750	-19,470	-1.45%	0	12,645	-2,448	7,816	636	845	(30,512)
10/8/2024	1,246,230	1,261,270	15,040	1.19%	0	2,376	-4,013	7,684	1,062	875	15,802
10/9/2024	1,222,550	1,219,710	-2,840	-0.23%	0	1,837	115	7,645	760	840	(5,632)
10/10/2024	887,350	891,740	4,390	0.49%	0	1,393	961	8,778	1,174	995	1,041
10/11/2024	834,910	838,740	3,830	0.46%	0	265	-2,258	8,700	1,433	1,013	4,810
10/12/2024	1,200,360	1,198,900	-1,460	-0.12%	0	1,314	-1,723	7,813	1,086	890	(1,940)
10/13/2024	624,670	638,620	13,950	2.18%	0	284	188	7,825	707	853	12,625
10/14/2024	1,372,430	1,372,700	270	0.02%	0	1,294	-1,175	8,832	1,062	989	(838)
10/15/2024	1,293,570	1,304,470	10,900	0.84%	0	619	823	8,685	1,151	984	8,474
10/16/2024	1,013,730	1,018,870	5,140	0.50%	0	2,493	-665	9,554	1,390	1,094	2,217
10/17/2024	794,950	796,500	1,550	0.19%	0	153	-984	8,567	816	938	1,442
10/18/2024	850,050	858,930	8,880	1.03%	0	998	-150	8,988	1,267	1,025	7,006
10/19/2024	1,250,200	1,254,710	4,510	0.36%	0	2,443	94	9,086	1,135	1,022	951
10/20/2024	901,450	900,100	-1,350	-0.15%	0	1,426	364	9,191	1,345	1,054	(4,194)
10/21/2024	1,280,390	1,284,190	3,800	0.30%	0	7,808	4,661	11,055	2,100	1,316	(9,984)
10/22/2024	1,373,870	1,373,300	-570	-0.04%	0	4,911	-45	10,896	1,940	1,284	(6,719)
10/23/2024	1,696,280	1,698,430	2,150	0.13%	0	998	-2,847	10,534	1,505	1,204	2,795
10/24/2024	1,162,780	1,164,370	1,590	0.14%	0	3,585	1,752	9,303	1,345	1,065	(4,812)
10/25/2024	1,404,590	1,408,080	3,490	0.25%	0	1,625	-1,900	9,371	999	1,037	2,728
10/26/2024	1,408,530	1,406,840	-1,690	-0.12%	0	1,302	-1,766	10,035	1,680	1,172	(2,397)
10/27/2024	550,050	604,790	54,740	9.05%	0	735	-77	7,517	839	836	53,246
10/28/2024	967,610	983,430	15,820	1.61%	0	1,624	-505	9,038	941	998	13,703
10/29/2024	1,217,750	1,218,380	630	0.05%	0	7,176	-792	8,933	2,614	1,155	(6,908)
10/30/2024	1,057,270	1,058,950	1,680	0.16%	0	1,559	-702	9,425	2,890	1,232	(409)
10/31/2024	1,293,850	1,300,290	6,440	0.50%	0	867	-3,855	8,688	1,705	1,039	8,390
11/1/2024	3,197,870	3,193,590	-4,280	-0.13%	0	1,412	-3,416	9,054	1,662	1,072	(3,347)
11/2/2024	2,682,820	2,659,420	-23,400	-0.88%	0	1,140	421	8,621	1,566	1,019	(25,979)
11/3/2024	1,302,820	1,327,700	24,880	1.87%	0	3,456	3,594	7,941	1,847	979	16,850
11/4/2024	2,969,480	2,947,240	-22,240	-0.75%	0	744	4,934	9,764	2,379	1,214	(29,132)
11/5/2024	4,543,250	4,540,920	-2,330	-0.05%	0	1,927	397	9,577	1,465	1,104	(5,758)
11/6/2024	5,433,980	5,432,720	-1,260	-0.02%	0	3,950	-266	9,739	1,319	1,106	(6,050)
11/7/2024	3,072,780	3,076,970	4,190	0.14%	0	4,132	-225	9,960	1,718	1,168	(885)
11/8/2024	3,262,050	3,249,690	-12,360	-0.38%	0	3,678	-2,089	9,586	1,599	1,119	(15,068)
11/9/2024	1,308,990	1,350,040	41,050	3.04%	0	1,224	106	7,768	1,544	931	38,789
11/10/2024	2,064,750	2,043,920	-20,830	-1.02%	2,893	2,775	500	8,293	1,660	995	(27,993)

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
11/11/2024	2,641,410	2,636,680	-4,730	-0.18%	0	3,392	1,480	9,921	2,313	1,223	(10,826)
11/12/2024	711,790	803,560	91,770	11.42%	0	1,166	-102	8,018	878	890	89,817
11/13/2024	1,768,730	1,780,200	11,470	0.64%	0	6,534	-3,798	10,021	1,393	1,141	7,592
11/14/2024	3,235,610	3,233,360	-2,250	-0.07%	0	2,237	-3,128	9,962	849	1,081	(2,441)
11/15/2024	2,878,140	2,878,230	90	0.00%	0	1,902	-1,623	10,472	1,097	1,157	(1,346)
11/16/2024	617,460	703,450	85,990	12.22%	0	1,791	-242	7,641	560	820	83,621
11/17/2024	939,950	1,017,160	77,210	7.59%	0	2,558	-194	8,440	1,094	953	73,893
11/18/2024	2,145,540	2,163,140	17,600	0.81%	0	6,154	-594	10,998	1,317	1,232	10,808
11/19/2024	3,186,230	3,183,230	-3,000	-0.09%	0	1,074	-196	11,855	1,738	1,359	(5,238)
11/20/2024	3,805,090	3,888,250	83,160	2.14%	0	4,589	-8,217	12,220	1,448	1,367	85,421
11/21/2024	3,971,460	4,003,200	31,740	0.79%	0	1,445	-1,804	12,103	1,485	1,359	30,740
11/22/2024	3,468,610	3,462,550	-6,060	-0.18%	0	4,420	-8,121	10,306	1,134	1,144	(3,503)
11/23/2024	2,602,460	2,606,810	4,350	0.17%	0	433	-1,577	9,755	1,211	1,097	4,397
11/24/2024	1,538,390	1,543,290	4,900	0.32%	0	550	-120	8,668	1,127	979	3,490
11/25/2024	1,167,730	1,171,570	3,840	0.33%	0	228	-28	8,926	1,282	1,021	2,619
11/26/2024	3,277,930	3,308,820	30,890	0.93%	0	776	-14	10,946	1,098	1,204	28,924
11/27/2024	2,922,410	2,952,880	30,470	1.03%	0	757	1,974	10,925	1,014	1,194	26,545
11/28/2024	804,480	878,900	74,420	8.47%	0	45	0	7,292	1,332	862	73,513
11/29/2024	1,538,930	1,573,910	34,980	2.22%	0	771	24	9,594	1,140	1,073	33,112
11/30/2024	2,124,470	2,154,480	30,010	1.39%	0	3,950	144	10,446	1,170	1,162	24,755
12/1/2024	2,948,850	2,946,580	-2,270	-0.08%	0	2,138	340	11,469	999	1,247	(5,995)
12/2/2024	4,250,720	4,263,330	12,610	0.30%	0	1,073	4,978	13,359	1,418	1,478	5,081
12/3/2024	2,891,890	2,888,240	-3,650	-0.13%	0	3,651	550	13,093	1,529	1,462	(9,314)
12/4/2024	1,944,630	1,959,380	14,750	0.75%	0	1,438	599	11,977	1,452	1,343	11,371
12/5/2024	5,038,810	5,052,070	13,260	0.26%	0	1,712	1,531	13,908	1,703	1,561	8,456
12/6/2024	3,607,350	3,624,310	16,960	0.47%	0	2,059	-521	13,448	2,494	1,594	13,828
12/7/2024	572,270	679,200	106,930	15.74%	0	1,245	-87	8,372	1,485	986	104,787
12/8/2024	1,206,890	1,201,340	-5,550	-0.46%	0	721	107	8,424	1,410	983	(7,362)
12/9/2024	1,591,580	1,572,150	-19,430	-1.24%	0	97	126	10,871	1,531	1,240	(20,893)
12/10/2024	2,516,610	2,499,250	-17,360	-0.69%	0	3,478	2,366	11,863	3,269	1,513	(24,718)
12/11/2024	2,798,700	2,792,250	-6,450	-0.23%	0	1,490	-792	12,994	2,451	1,544	(8,692)
12/12/2024	4,725,690	4,808,670	82,980	1.73%	0	1,678	1,478	13,359	3,604	1,696	78,127
12/13/2024	2,943,770	2,951,720	7,950	0.27%	0	744	-195	13,904	1,854	1,576	5,825
12/14/2024	3,200,340	3,174,650	-25,690	-0.81%	0	260	177	12,706	1,643	1,435	(27,562)
12/15/2024	2,359,590	2,345,480	-14,110	-0.60%	0	456	252	12,779	2,303	1,508	(16,326)
12/16/2024	1,570,670	1,551,470	-19,200	-1.24%	0	3,603	36	11,738	2,079	1,382	(24,221)
12/17/2024	6,426,060	6,439,680	13,620	0.21%	0	2,488	-769	14,862	2,451	1,731	10,170
12/18/2024	4,565,710	4,554,930	-10,780	-0.24%	0	1,302	-1,068	14,344	1,658	1,600	(12,614)
12/19/2024	2,006,520	1,996,940	-9,580	-0.48%	0	765	-83	12,480	1,587	1,407	(11,668)
12/20/2024	3,244,490	3,226,200	-18,290	-0.57%	0	284	61	12,559	1,468	1,403	(20,038)
12/21/2024	3,126,580	3,118,760	-7,820	-0.25%	0	3,036	921	14,167	1,532	1,570	(13,347)
12/22/2024	1,696,460	1,676,330	-20,130	-1.20%	0	1,598	-11	10,777	1,316	1,209	(22,926)
12/23/2024	3,389,750	3,371,690	-18,060	-0.54%	0	914	-1,055	12,409	1,531	1,394	(19,313)
12/24/2024	3,019,620	2,986,990	-32,630	-1.09%	0	1,822	-273	12,718	1,522	1,424	(35,603)
12/25/2024	2,168,890	2,149,680	-19,210	-0.89%	0	1,614	-112	12,200	2,862	1,506	(22,218)
12/26/2024	2,268,760	2,232,610	-36,150	-1.62%	0	763	56	13,000	2,119	1,512	(38,482)
12/27/2024	2,508,230	2,479,440	-28,790	-1.16%	0	993	345	12,111	1,879	1,399	(31,527)
12/28/2024	2,173,680	2,150,550	-23,130	-1.08%	0	981	-27	10,434	1,944	1,238	(25,323)
12/29/2024	2,748,210	2,721,270	-26,940	-0.99%	0	4,814	353	11,060	1,061	1,212	(33,319)
12/30/2024	2,837,600	2,809,200	-28,400	-1.01%	0	3,303	-274	12,101	1,213	1,331	(32,761)
12/31/2024	776,960	918,480	141,520	15.41%	0	310	-293	9,418	1,716	1,113	140,389
Total	**685,548,240**	**689,487,860**	**3,939,620**	**0.01**	**14,383**	**748,954**	**76,058**	**3,531,177**	**776,113**	**442,430**	**2,657,795**

Excessive Deficient Energy Deployment Charge by NSP Resource

LOCATION	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Agassiz Beach1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G2	$ -	$ -	$ -	$ 845	$ 194	$ 12,873	$ 1,000	$ 1,197	$ -	$ 10	$ 927	$ 81
Anson_G3	$ 19	$ -	$ -	$ -	$ 398	$ 12,702	$ 2,037	$ 2,394	$ 68	$ 30	$ 24	$ 746
Anson_G4	$ 6	$ 5	$ -	$ 2,606	$ 998	$ 4,930	$ 3,346	$ 136	$ 87	$ 85	$ 54	$ 780
BayFrnt_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BigFalls_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G52	$ 4,027	$ 19	$ 383	$ 318	$ -	$ -	$ 184	$ 2	$ 24	$ 516	$ 335	$ 604
Blk_Dog_G6	$ 896	$ 538	$ 4,661	$ -	$ 7,723	$ 9,386	$ 24,126	$ 18,282	$ 26,277	$ 15,242	$ 12,727	$ 4,396
Blue_Lk_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15
Blue_Lk_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,208	$ -	$ -	$ -	$ -
Blue_Lk_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G7	$ 750	$ 3	$ -	$ -	$ -	$ -	$ 928	$ 11,716	$ 4,838	$ 1,569	$ 338	$ 33
Blue_Lk_G8	$ 733	$ -	$ -	$ 29	$ 5,605	$ -	$ 224	$ 2,040	$ 166	$ 3,939	$ 73	$ 31
BuffR_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BuffR_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Canon_Falls1	$ 42	$ -	$ 9	$ 2	$ -	$ 1,835	$ 4,165	$ 8,850	$ 10,852	$ 8,141	$ 2,548	$ 564
Canon_Falls2	$ 1,166	$ 397	$ 795	$ 2,533	$ 2,432	$ 13,015	$ 7,663	$ 22,990	$ 22,217	$ 13,256	$ 3,874	$ 1,031
CC Highbridge1	$ 1,152	$ 27	$ 153	$ 612	$ 157	$ 119	$ 172	$ 120	$ 194	$ -	$ 437	$ 1,432
CC Highbridge2	$ 1,613	$ 52	$ 245	$ 65	$ 1,554	$ 13	$ 104	$ 43	$ 242	$ -	$ 1,501	$ 860
CC Mankato1	$ 1,007	$ 793	$ 2,671	$ 1,459	$ 1,620	$ 3,776	$ 4,903	$ 7,656	$ 3,808	$ 2,986	$ 4,827	$ 5,864
CC Mankato2	$ 984	$ 497	$ 964	$ 1,721	$ 1,726	$ 1,706	$ 4,798	$ 7,895	$ 5,089	$ 3,280	$ 2,963	$ 6,592
CCRiverside1	$ 14,319	$ 246	$ 3,183	$ 54	$ 4,311	$ 1,651	$ 194	$ 6,155	$ 2,310	$ 5,650	$ 6,006	$ 10,179
CCRiverside2	$ 11,554	$ 11	$ 6	$ -	$ 1,773	$ 2,300	$ 316	$ 4,927	$ 5,369	$ 3,824	$ 1,940	$ 3,635
CedarFalls_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ -	$ -	$ -
CHPFALTR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CORNEL	$ 31	$ 63	$ -	$ -	$ -	$ 113	$ 4,694	$ 2,007	$ 129	$ -	$ 175	$ 10
Elliot_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,052	$ 395	$ -	$ -	$ -
Garwin_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hennipin1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Herc_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HOLCOM	$ 11	$ 9	$ -	$ -	$ -	$ 116	$ 2,846	$ 1,530	$ 91	$ -	$ 27	$ 6
InvrHils_1	$ 73	$ -	$ -	$ 2	$ -	$ -	$ -	$ 547	$ -	$ 2	$ 607	$ 33
InvrHils_2	$ 3	$ -	$ -	$ -	$ -	$ 1	$ 810	$ 220	$ 47	$ 1	$ 503	$ 25
InvrHils_3	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,265	$ 105	$ 34	$ 4	$ 556	$ 2
InvrHils_4	$ 2	$ -	$ -	$ 1	$ 15	$ 2	$ 827	$ 473	$ 62	$ 6	$ 1,328	$ 275
InvrHils_5	$ 6	$ -	$ -	$ 1	$ 1	$ -	$ 1	$ 4	$ 1	$ 63	$ 61	$ 213
InvrHils_6	$ 8	$ -	$ -	$ -	$ 11	$ -	$ -	$ 101	$ 62	$ 10	$ 16	$ 63
JIMFL	$ 18	$ 12	$ -	$ -	$ -	$ 155	$ 7,619	$ 1,997	$ 120	$ -	$ 41	$ 15
King_G1	$ 7,041	$ 59	$ -	$ -	$ -	$ -	$ 3,043	$ 4,048	$ -	$ -	$ -	$ -
LSPower_1	$ 6,098	$ 2,271	$ 8,098	$ 7,133	$ 8,381	$ 12,360	$ 14,800	$ 14,817	$ 18,788	$ 15,200	$ 23,211	$ 1,528
MankatoCT1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MankatoCT2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MankatST31	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MankatST32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Menomone_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monticello_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ADAMSWD1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BIGBLUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2	$ -	$ -
NSP.BR_DIR_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BSTAR1.WND	$ -	$ -	$ -	$ 28	$ -	$ -	$ 183	$ 52	$ 197	$ -	$ 28	$ -
NSP.BSTAR2.WND	$ -	$ -	$ -	$ 6	$ -	$ -	$ 21	$ 19	$ 98	$ -	$ -	$ -
NSP.CH_DIR_TR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CWN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CWN2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.DANIELSN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.FENTON.WND	$ 2	$ 6	$ 3	$ 30	$ 35	$ 8	$ 4	$ 3	$ -	$ 40	$ 5	$ 12
NSP.MARSHSOLAR	$ -	$ -	$ -	$ 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MNDAK.WND	$ 4	$ 9	$ 3	$ 15	$ 1	$ 4	$ -	$ 10	$ 23	$ 3	$ -	$ -
NSP.MORAINE2	$ 2	$ -	$ -	$ 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS1	$ -	$ -	$ -	$ 2	$ 4	$ 0	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS2	$ -	$ -	$ -	$ 2	$ 3	$ 0	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES.WND	$ 2	$ -	$ -	$ -	$ 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NORTHN.WND	$ -	$ -	$ -	$ 1	$ -	$ 7	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NSTARSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL.WND	$ 2	$ 6	$ 66	$ -	$ -	$ 9	$ 3	$ -	$ -	$ 19	$ 30	$ -
NSP.PRISL1_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PRISL2_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE	$ -	$ -	$ -	$ 17	$ 17	$ -	$ -	$ -	$ 4	$ -	$ -	$ -
NSP.PVALEY.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.RAETNA.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.RIVRSD10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.SHAKOBIO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.SHERC1.SLR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERC3	$ 3,486	$ 776	$ 3,053	$ 5,914	$ 3,753	$ 1,627	$ 8,456	$ 4,148	$ 2,279	$ -	$ 4,047	$ 10,223
SHERCO_G1	$ 3,617	$ 2,222	$ -	$ 0	$ 7,575	$ 6,465	$ 6,184	$ 562	$ 2,129	$ 118	$ -	$ 1,545

Excessive Deficient Energy Deployment Charge by NSP Resource

LOCATION	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
South Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St Paul Cogen	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
StCloud_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
STCRO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UofMGen1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
W_Triw_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WAUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West_Pipestone	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_1	$ 9	$ -	$ -	$ -	$ 2,590	$ 516	$ 70	$ -	$ -	$ -	$ -	$ 8
Wheaton_2	$ 6	$ 417	$ -	$ -	$ 9,615	$ 774	$ 2	$ -	$ -	$ -	$ -	$ 2
Wheaton_3	$ -	$ -	$ -	$ -	$ 710	$ 604	$ 17	$ -	$ -	$ -	$ -	$ 2
Wheaton_4	$ 12	$ -	$ -	$ -	$ 2,690	$ 919	$ 53	$ -	$ 5	$ -	$ -	$ 24
Wi Eastridge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewngton 2	$ 0	$ 1	$ -	$ -	$ 1	$ 1	$ -	$ -	$ -	$ -	$ -	$ -
Wi Grand Meadow	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Jeffers 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi UILK_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Valley View	$ -	$ 4	$ -	$ -	$ 3	$ 0	$ -	$ -	$ -	$ -	$ -	$ -
Wi Velva	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Windvest_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR3	$ 0	$ -	$ -	$ -	$ -	$ 6	$ -	$ -	$ 9	$ -	$ -	$ -
WISSOTATR4	$ -	$ -	$ -	$ -	$ -	$ 117	$ -	$ -	$ 6	$ -	$ -	$ -
Woodstk_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals	**$ 51,560**	**$ 5,003**	**$ 21,168**	**$ 17,382**	**$ 36,900**	**$ 77,055**	**$ 90,065**	**$ 135,509**	**$ 101,269**	**$ 73,815**	**$ 65,100**	**$ 39,014**

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Agassiz Beach1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BigFalls_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G52	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G6	$ -	$ -	$ -	$ -	$ -	$ 2,562	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BuffR_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BuffR_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Canon_Falls1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Canon_Falls2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Highbridge1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Highbridge2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Mankato1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Mankato2	$ -	$ 38	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCRiverside1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCRiverside2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CedarFalls_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR1	$ 227	$ -	$ -	$ -	$ -	$ -	$ 62	$ -	$ -	$ -	$ 603	$ -
CHPFALTR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CORNEL	$ 576	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 221	$ -	$ 1,549	$ -
Elliot_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Garwin_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hennipin1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Herc_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HOLCOM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 247	$ -	$ -	$ -
InvrHils_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
JIMFL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 297	$ -	$ -	$ -
King_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LSPower_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MankatoCT1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MankatoCT2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MankatST31	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MankatST32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Menomone_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monticello_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ADAMSWD1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BIGBLUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BR_DIR_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BSTAR1.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BSTAR2.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CH_DIR_TR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CWN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CWN2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.DANIELSN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.FENTON.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MARSHSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MNDAK.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MORAINE2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NORTHN.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NSTARSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PRISL1_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PRISL2_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PVALEY.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.RAETNA.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.RIVRSD10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.SHAKOBIO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.SHERC1.SLR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERC3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERCO_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
South Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St Paul Cogen	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
StCloud_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
STCRO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UofMGen1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
W_Triw_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WAUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West_Pipestone	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Eastridge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewngton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Grand Meadow	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Jeffers 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi UILK_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Valley View	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Velva	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Windvest_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR3	$ 211	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR4	$ -	$ 32	$ -	$ -	$ -	$ -	$ 6,889	$ -	$ 128	$ -	$ 741	$ -
Woodstk_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals	**$ 1,014**	**$ 69**	**$ -**	**$ -**	**$ -**	**$ 2,562**	**$ 6,952**	**$ -**	**$ 893**	**$ -**	**$ 2,893**	**$ -**

2024 WIND CURTAILMENT REPORT

I. INTRODUCTION

The Commission's April 4, 2006 Order regarding curtailment payments to wind developers (Docket No. E999/AA-04-1279) requires the Company to provide in future Annual Automatic Adjustment of Charges (AAA) reports a projection of wind generation curtailment costs given existing and planned wind-generated energy purchases and transmission system needs. The Commission's June 12, 2019 Order in Docket No. E999/CI-03-802 approved the disposition of AAA reporting requirements as agreed to by the Company and the Department. The Company and the Department agreed that curtailment reporting could be reformatted to provide support for increased curtailment, in addition to providing detailed curtailment data by unit and by curtailment code.

Below we summarize the Company's experience regarding wind curtailment payments and provide a discussion of the drivers for increased wind curtailment payments during the 2024 reporting year as compared to the 2024 forecast. Part C, Attachment 2 shows detailed curtailment payments by unit and by curtailment code, in compliance with the Commission's February 6, 2008 Order in Docket Nos. E,G999/AA-06-1208 and E002/M-04-1970 *et al.*

We most recently discussed and provided an estimate of potential curtailment payments and the assumptions used to develop our 2025 curtailment forecast in our May 1, 2024 Petition and July 31, 2024 Reply Comments in Docket No. E002/AA-24-63. We will provide an estimate of 2026 curtailment payments, including forecast assumptions, in our 2026 Fuel Forecast Petition to be filed by May 1, 2025.

System conditions and wind project development are very dynamic and actual curtailment may vary from what is projected in this report. The Company will continue to participate in discussions regarding transmission planning and operations to identify needs and work to manage future costs. We will continue to refine and gather information for use in future updates to be submitted with subsequent fuel true-up and forecast reports.

II. CURTAILMENT OVERVIEW

The Company again expects that wind curtailment from Power Purchase Agreement (PPA) facilities will occur in the foreseeable future, and 2024 curtailment can be attributed to regional and localized congestion resulting from the lack of sufficient transmission capacity to accommodate the large concentration of wind facilities in Minnesota, North Dakota, South Dakota, and Iowa. The transmission capacity required to deliver the wind is often further reduced by transmission outages.

The Company is making significant efforts to reduce the impact of congestion, and therefore curtailment, by sponsoring transmission upgrades that can be completed in the near term, upgrading substation equipment where that is the limiting element on a transmission line, prioritizing repairs on transmission facilities that impact congestion, optimizing transmission outages to limit duration along with scheduling outages during periods of lower wind when possible.

Another factor that contributed to higher curtailment at Company PPA facilities is the status of a wind project's Production Tax Credit (PTC). Projects without PTCs are curtailed before projects with PTCs since they are a higher priced resource.[1] The lack of PTCs is a significant factor related to Company curtailments since a number of PPA projects do not have PTCs and are reducing the curtailment on other area projects regardless of the owner.

The Company, along with MISO and other area utilities, have taken a number of steps to create additional transmission capacity to reduce wind curtailment and congestion. These steps include the development the CapX2020 transmission projects (CapX2020), Huntley – Wilmarth 345 kV line, the MISO Multi-Value Projects (MVPs), and the Brookings – Lyon County 345 kV second circuit. The Company has also worked with the Grid North Partners,[2] to complete a number of transmission improvement projects[3] that are specifically designed to reduce congestion and curtailment.

Work has begun on the MISO Long-Range Transmission Planning (LRTP) Tranche 1 projects designed to enable reliable and economic delivery of energy in the future with lower-carbon resources. The LRTP projects will create additional transmission capacity for new generating resources and positively impact curtailment. The LRTP Tranche 1 projects have projected in-service dates of 2029-2030.

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[1] Projects with PTCs are bid into the market at a negative value since the owner will lose the PTC if curtailed while projects without PTCs are bid in at zero dollars.
[2] The Grid North Partners include Central Municipal Power Agency/Services, Dairyland Power Cooperative, Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, WPPI Energy, and Xcel Energy.
[3] https://www.startribune.com/minnesota-utilities-spending-130-million-to-improve-wind-energy-transmission-great-river-energy-xcel/600308291/

MISO has also approved the LRTP Tranche 2 projects which are also designed to create additional transmission capacity for new generating resources and positively impact curtailment. The LRTP Tranche 2 projects have projected in-service dates in the 2030s.

MISO identifies wind facilities that can be controlled through Automatic Generation Control[4] as Dispatchable Intermittent Resources (DIR), which provide better management of the wind resources. Under this system, a number of existing PPA wind facilities that are capable of operating as DIR, along with all new wind facilities, are registered with MISO as DIR. DIR facilities are given set point instructions every five minutes and rely on Automated Generation Control (AGC) technology, which automatically controls wind project output. DIR allows wind generators to be operated more like traditional generating facilities and, as a result, MISO is able to more quickly and accurately respond to system conditions.

Table 1 shows the current PPA wind facilities associated with this report that are registered and operate as DIR.

[4] MISO requires all new intermittent resources, including non-dispatchable facilities that are being repowered, to be fully dispatchable. The Company has contracts with a number of PPA Facilities that are not dispatchable.

Table 1
DIR PPA Facilities

Wind Project	MW
Big Blue	36
Cisco	8
Crowned Ridge 1	200
Dakota Range 3	150
Fenton	200
Glen Ullin Wind	106
MinnDakota	150
Moraine II	50
Odell	200
Prairie Rose	200
Valley View	10
Zephyr	30
Total	1,340

MISO manages generation, including DIR generation, in the Real Time market which is described on the MISO website as the following.

> The Real-Time Market is a continuous process for balancing supply and demand at least-cost while recognizing current operating conditions. This includes any deviations from the day-ahead plan as a result of unanticipated and unhedged congestion due to unexpected changes. The Real Time Market dispatches the least-cost generation resources to satisfy system demand without overloading the transmission network.
>
> MISO uses the Security Constrained Economic Dispatch (SCED) algorithm to provide co-optimized clearing solutions in the Real-Time Market. The objective of the Security Constrained Economic Dispatch (SCED) algorithm is to minimize cost while meeting forecasted demand, scheduled interchange, and operating reserves requirements, which are subject to transmission congestion and other system limitations. SCED produces Balanced injections and withdrawals, congestion management solutions and LMP and MCP. The SCED runs every five minutes during the Operating Hour to establish the dispatch instruction for generation resources. SCED produces Resource

Energy Dispatch Targets, Dispatch target information vis setpoint instructions, RT LMP and RT MCP. MISO sends out a five-minute dispatch target to each resource and repeats throughout the Operating Day.

1. *Curtailment Procedures*

MISO performs a 10-minute forecast every five minutes which is used as the maximum limit for the wind farm in the Unit Dispatch System. MISO sends five-minute dispatch instructions to DIR wind farms. When LMP drops below the offer price of the DIR unit, the farm is automatically dispatched down. The setpoint is sent to the DIR wind farm, and the facility is automatically curtailed. Both PTC and non-PTC DIR wind farms are managed by MISO through automatic control, and these facilities are required to comply with the MISO cost signals. Failure to comply would expose the Company to Revenue Sufficiency Guarantee (RSG) charges. More curtailment occurs at non-PTC wind farms.

2. *Real Time Binding Constraints*

Real time binding constraints are the transmission facilities that are identified in the SCED that would overload in anticipation of the next contingency. The SCED would send setpoint instruction to redispatch generation to eliminate the constraint.

A number of factors result in real time binding constraints which cause curtailment, including: 1) the oversubscription of the transmission system resulting in more wind generation than the transmission system can accommodate; 2) the relationship between wind and load levels where more curtailment will occur during periods of higher wind and lower load; 3) planned and emergency transmission outages required for construction, maintenance or repair activities; and 4) wind generation projects going into service before all required transmission facilities are completed.

The Company internally classifies Real Time Binding Constraints (RTBCs) as Regional Constraints and Localized Constraints. Regional Constraints are those that have an impact on multiple generating facilities located in a larger area. Localized Constraints are those that have an impact on specific generating facilities located in a specific area. Transmission outages can impact both Regional and Localized Constraints. The most frequent 2024 Regional and Localized real time binding constraints impacting the Company owned and PPA facilities are listed in Tables 2 and 3 below.

Note: the Company has worked to identify binding constraints that are likely to occur going forward and have been implementing plans to mitigate these constraints. The mitigation plans are designed to cost effectively reduce both curtailment and congestion. These plans were discussed in detail in our December 22, 2021 compliance filing in Docket No. E002/AA-21-295.

Table 2
2024 Regional Real Time Binding Constraints

Constraint Name	Contingency Description	State	Hours
[PROTECTED DATA BEGINS			
	PROTECTED DATA ENDS]		

Table 3
2024 Localized Real Time Binding Constraints

Constraint Name	Contingency Description	State	Hours
[PROTECTED DATA BEGINS			
	PROTECTED DATA ENDS]		

[5]

[5] **[PROTECTED DATA BEGINS
PROTECTED DATA ENDS].**

Table 4 lists the transmission outages that negatively impacted regional or localized RTBCs and contributed to the curtailment. The outages, which were both planned and unplanned, were required to support area road construction, to allow maintenance or repair activities, to allow upgrades to existing transmission facilities or construction of new regional transmission facilities and support new generator interconnections.

Table 4
2024 Transmission Outages

Outage Request_ID	Company	KV	From_Station	To_Station	Actual_Start	Actual_End
[PROTECTED DATA BEGINS						
				PROTECTED DATA ENDS]		

The Company believes that the following Real Time Binding Constraints were negatively impacted by outages listed in Table 4.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

The Company believes that the following Real Time Binding Constraints are likely to occur during normal operations but may be made worse by particular transmission outages.

[PROTECTED DATA BEGINS

-
-
-
-
-
-
-
-
-
-
-

-
-
-

PROTECTED DATA ENDS]

The amount of wind generation interconnected to the transmission system has a significant impact on congestion and curtailment – especially if it is placed in-service prior to the completion of the necessary transmission upgrades. The Company is aware of 7,598 MW of wind generating projects in Minnesota, North Dakota, South Dakota, and Iowa that have recently gone into service and 3,431 MW that may go into service in the next few years. The in-service wind includes 2,026 MW of Company-owned and PPA wind. Table 5 shows wind generating facilities that have recently gone into service and Table 6 shows wind generating facilities that may go into service in the next few years. All of these wind projects will be registered and operated as DIRs.

Table 5
Wind Generation Additions – In Service

Company	MW	Location	In-Service Dates
Alliant Energy	1,150	IA	2019-2022
Great River Energy	509	ND	2020-2025
MidAmerican	3,402	IA	2019-2021
Minnesota Municipal Power Agency	111	MN	2022
Minnesota Power	250	MN	2020
Northern States Power	2,026	MN, SD	2019-2022
Otter Tail Power	150	ND	2020
Total	7598		

Table 6
Wind Generation Additions – Planned

Company	MW	Location	In-Service Dates
Alliant Energy	150	MN	Late 2027
Great River Energy	1239	ND	2025-2027
MidAmerican	2042	IA	Unknown
Total	3,431		

The required transmission upgrades for the planned wind projects may not all be in-service at the time the projects begin producing energy. In addition, a number of the projects are using surplus interconnection service at existing generating facilities which means they will not be required to install additional transmission facilities. These projects will impact real-time wind generation on the NSP System.

III. TRANSMISSION SYSTEM IMPROVEMENTS

Since 1994, wind energy resources have been the dominant factor in determining the need for transmission infrastructure improvements in southwestern Minnesota. To meet this need, the Company, often in cooperation with other utilities, has planned, engineered, and constructed a number of projects designed to increase the transmission capacity in that area. Table 7 lists historic southwest Minnesota projects that were developed by the Company.

Table 7
Southwest Minnesota Wind Projects

Transmission Project	Transmission Owner	In-Service Date
425 MW Wind Transmission Expansion Project	Xcel Energy	December 2006
825 MW Wind Transmission Expansion Project	Xcel Energy	June 2008
Buffalo Ridge Incremental Generation Outlet (BRIGO)	Xcel Energy	December 2009

Table 8 lists the CapX2020 transmission projects that were developed by the Company and other area utilizes which have provided additional transmission capacity on the Minnesota transmission system.

Table 8
CapX2020 Transmission Projects

Transmission Project	Transmission Owner	In-Service Date
Brookings County - Southeast Twin Cities 345 kV Line	Xcel Energy, Great River Energy	March 26, 2015
Fargo North Dakota - Northwest Twin Cities 345 kV Line	Xcel Energy, Great River Energy	April 2, 2015
Southeast Twin Cities - La Crosse, Wisconsin 345 kV Line	Xcel Energy, SMMPA and non-MISO	September 16, 2016

Table 9 lists the MISO Multi-Value Projects (MVP) that were developed by the Company and other area utilities. The MVPs were constructed to expand and enhance the region's transmission system, reduce congestion, provide access to affordable energy sources, and meet public policy requirements including renewable energy mandates. The Company participated in the construction of two of the projects.

Table 9
MVP Projects

Transmission Project	Transmission Owner	In-Service Date
Big Stone South to Brookings County 345 kV Line	Otter Tail Power Company, Xcel Energy	September 8, 2017
Lakefield Jct. - Winnebago - Winco - Kossuth County & Obrien County - Kossuth County - Webster 345 kV Line	MidAmerica Energy, ITC Midwest	September 27, 2018
North La Crosse - North Madison	American Transmission Company, Xcel Energy	December 12, 2018
Winco to Hazleton 345 kV Line	MidAmerica Energy, ITC Midwest	July 18, 2019
Ellendale to Big Stone South 345 kV Line	Otter Tail Power Company, Montana Dakota Utilities	February 5, 2019
Cardinal - Hickory Creek 345 kV Line	American Transmission Company, ITC Midwest	September 27, 2024

Table 10 lists other projects that that were, or are being, developed by the Company and other area utilities that were specifically designed to reduce congestion and curtailment. The Huntley – Wilmarth 345 kV line was constructed as a Market Efficiency Project (MEP) under the MISO MTEP process.

Table 10
Other Transmission Projects

Transmission Project	Transmission Owner	Planned/Actual In-Service Date
Huntley – Wilmarth 345 kV line	Xcel Energy, ITC Midwest	December 1, 2021
Brookings County – Lyon County 345 kV line second circuit	Grid North Partners	September 23, 2024
Helena – Chub Lake – Hampton Corner 345 kV line second circuit	Grid North Partners	Summer/Fall 2025
Installation of a new Forman 230/115 kV transformer	Otter Tail Power Company/ Xcel Energy	September 15, 2025

MISO has approved eighteen (18) LRTP Tranche 1 projects which are designed to expand and enhance the region's transmission system, reduce congestion, provide access to affordable energy sources, and meet public policy requirements including renewable energy mandates. Table 11 lists the LRTP Tranche 1 projects that will have a positive impact on the Minnesota transmission system including curtailment. The Company will be participating in the development and construction of three of the projects.

Table 11
LRTP Tranche 1 Projects

Transmission Project	Transmission Owner	Planned In-Service Date
Jamestown - Ellendale	MDU, OTP	12/31/2028
Big Stone South - Alexandria – Cassie's Crossing	Minnesota Power, Great River Energy, Otter Tail Power, Missouri River Energy Services	6/1/2030
Iron Range - Benton County – Cassie's Crossing	Minnesota Power, Great River Energy	6/1/2030
Wilmarth - North Rochester - Tremval	ATC, Dairyland Power, Xcel Energy	6/1/2028
Tremval - Eau Clair - Jump River	ATC, Xcel Energy	6/1/2028
Tremval - Rocky Run - Columbia	ATC, Xcel Energy	6/1/2029

IV. Wind Generation and Curtailment

Chart 1 shows planned and installed Company-owned and PPA wind generation facilities throughout the NSP service territory on an incremental and cumulative basis.

Chart 1

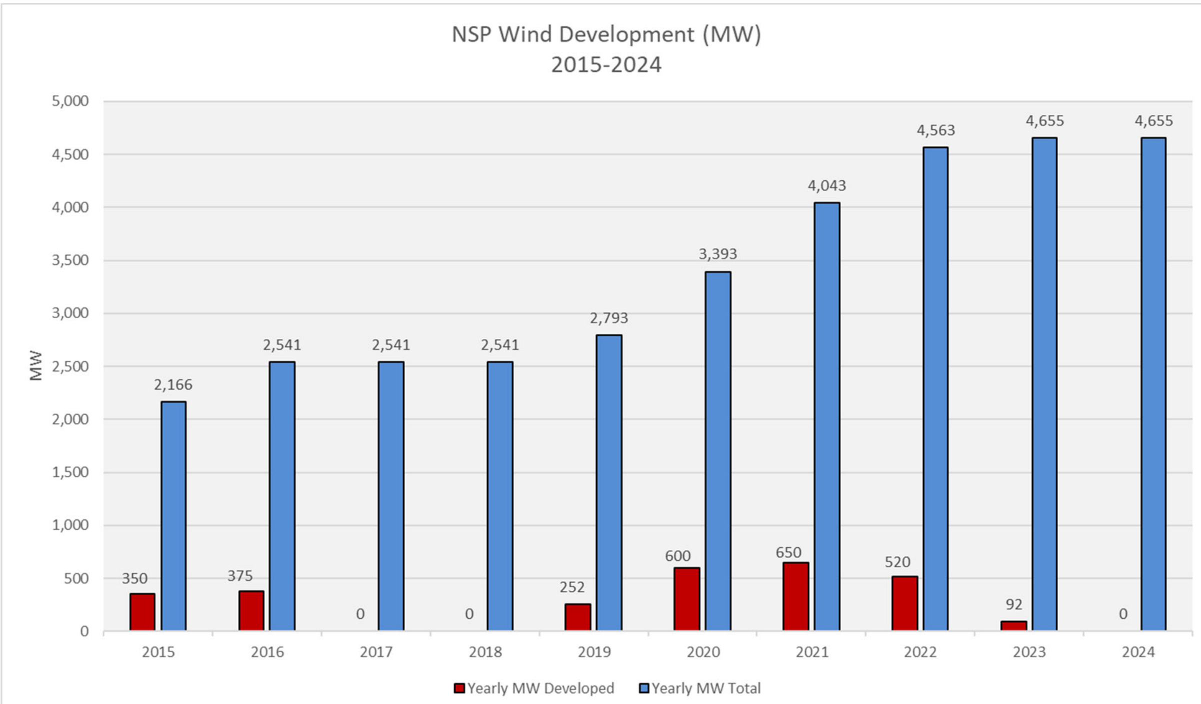


Chart 2 shows the comparison between total wind energy produced and the wind energy curtailed from the projects for 2024.[6] Chart 2 shows that wind curtailment is small compared to the total wind generation delivered. Chart 3 provides similar data for Company-owned wind facilities, as requested by the Department of Commerce in Information Request No. DOC-15 in Docket No. E002/AA-22-179.

Wind curtailment, as a tool to manage wind generation volumes when necessary, has had the positive benefit of facilitating a large amount of wind resources to be added to the system, which may not otherwise have been possible.

[6] Part C, Attachment 2.

Chart 2

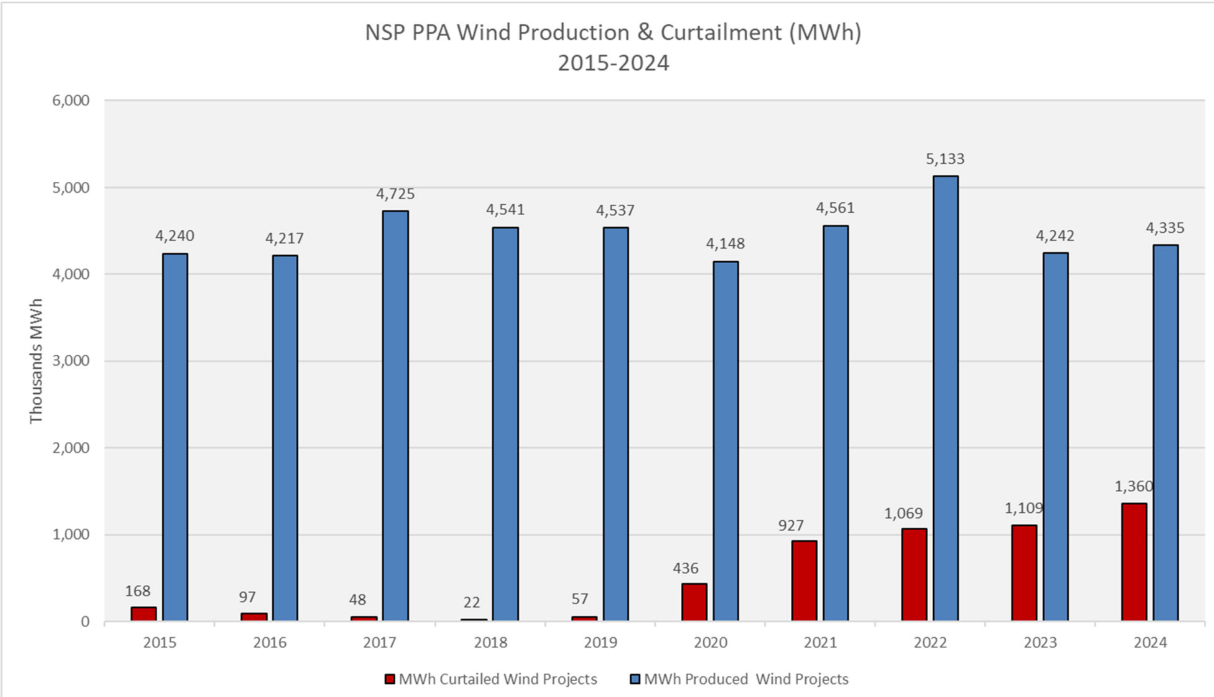
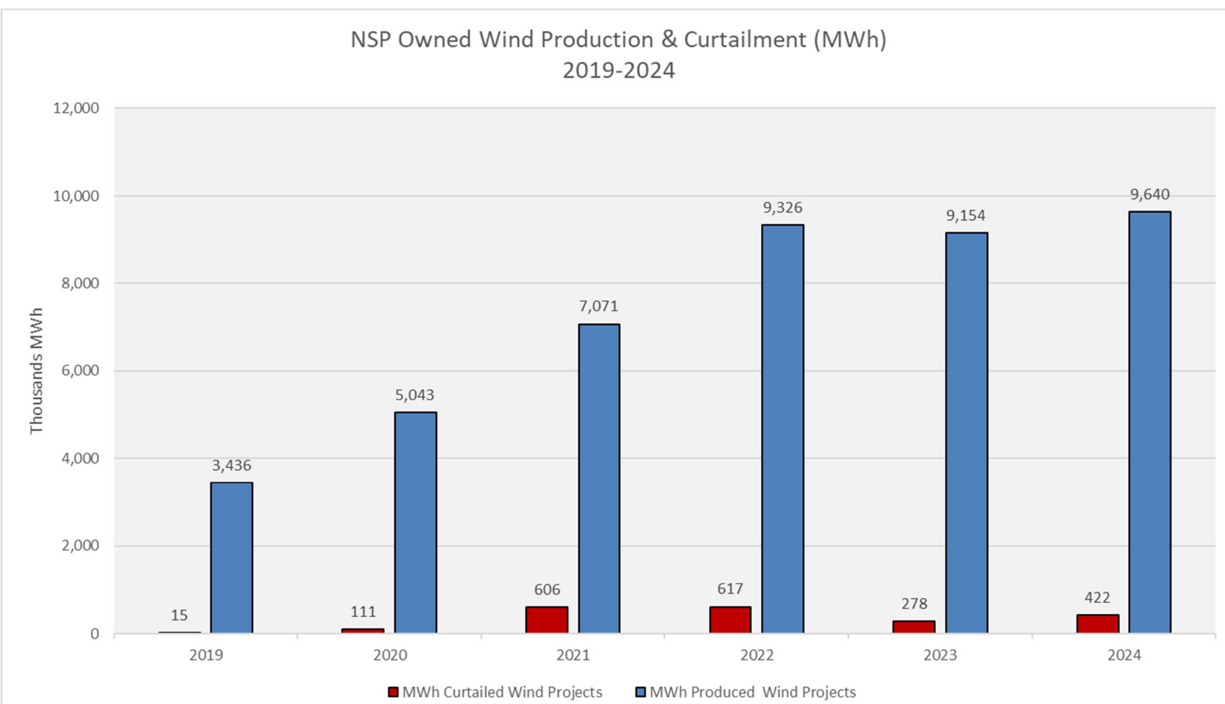


Chart 3



The 2024 Curtailment in summarized in Table 12.

Table 12
2023 Wind Curtailment MWh and Costs

	MWh	Costs
Curtailment	1,359,966	$56,609,937

It is important to note that of the $56,609,937 in total curtailment costs, the vast majority of these costs are associated with the contractual energy price of the PPAs. These are contractually obligated sunk costs which are not economically relevant to the decision to curtail the generation from a wind facility.[7]

1. *Curtailment Mitigation Efforts*

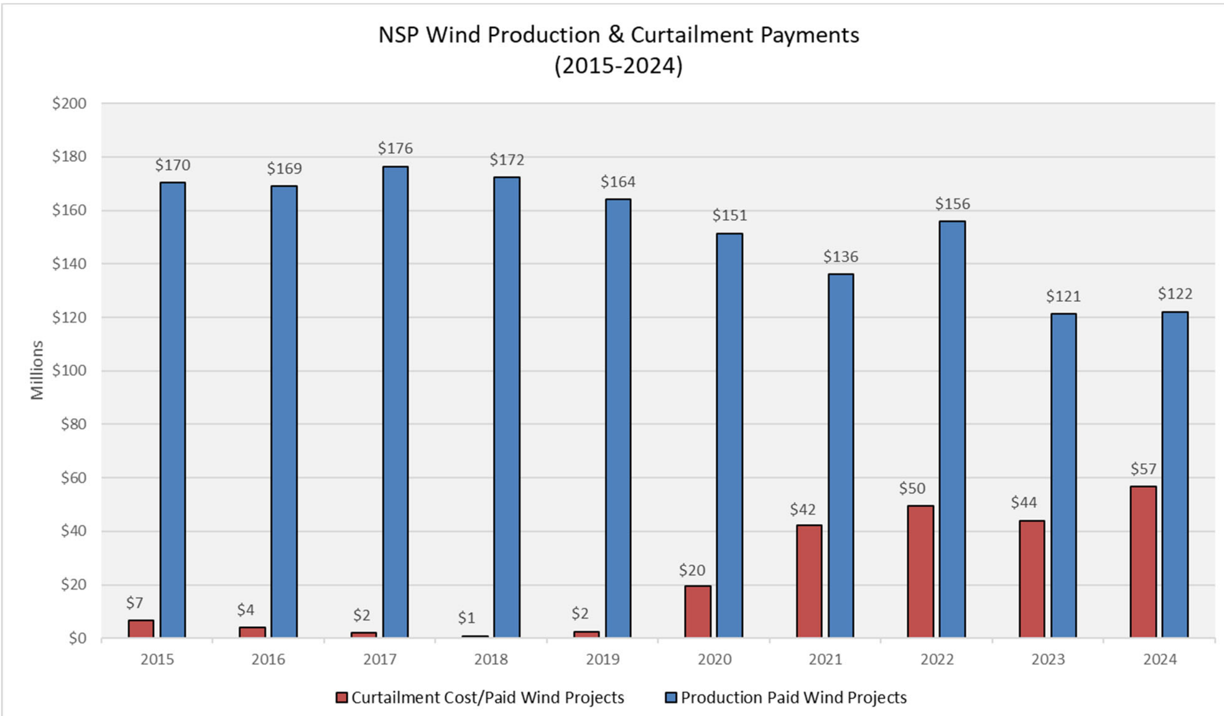
The Company has been working to schedule transmission outages to minimize curtailment for a number of years – performing multiple outages at the same time and scheduling these activities during times when wind is normally at its lowest levels – typically the summer months in the NSP service territory. While Xcel Energy attempts to plan outage work with this principle in mind, this is not always possible. Summer months are also high load months and transmission outages may not be possible due to load serving needs.

V. WIND PRODUCTION AND CURTAILMENT PAYMENTS

Chart 4 shows the corresponding production and curtailment costs for 2015 through 2024.[8] As with wind generation produced and curtailed, paid curtailment is a very small portion of total cost of wind generation on the system.

[7] The PPA contract language can generally be described as "take or pay" in which NSP must pay for the wind energy that could be produced, regardless of whether it is actually produced or if it is curtailed.
[8] The data for 2022-2024 is shown in Part C, Attachment 2.

Chart 4



In the past, the Company provided estimates of future potential curtailment payment estimates in the AAA Report. However, these estimates are now provided in our Annual Fuel Forecast Petitions, which is filed on May 1.

VI. ADDITIONAL COMPLIANCE ITEMS RELATED TO CURTAILMENT

As noted above, Part C, Attachment 2 shows detailed curtailment payments by unit and by curtailment code, in compliance with the Commission's February 6, 2008 Order in Docket Nos. E,G999/AA-06-1208 and E002/M-04-1970 *et al*. We provide curtailed MWh for Company owned wind facilities in Attachment 2a.

In compliance with Order Point 5 of the Commission's November 9, 2023 Order in Docket No. E002/AA-23-153, we provide detail about assumed versus actual wind capacity factors with and without curtailment for the Company's owned wind facilities in Attachment 2b.

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - 2024 Total

Production Month	Date Paid: Delivered MWh	Date Paid: Lost MWh	Wind Production Delivered: MWh Delivered	Wind Production Delivered: Amount Xcel Energy Paid	Lost Production: Lost MWh	Lost Production: Amount Xcel Energy Paid	Total Xcel Energy Paid
Jan-22			486,114.99	$ 15,421,309.72	133,508.58	$ 6,145,798.49	$ 21,567,108.21
Feb-22			502,705.35	$ 14,769,300.19	108,559.97	$ 4,988,995.72	$ 19,758,295.91
Mar-22			514,652.57	$ 15,019,353.70	92,798.08	$ 4,318,981.66	$ 19,338,335.36
Apr-22			530,699.02	$ 15,996,139.35	214,574.54	$ 9,782,194.55	$ 25,778,333.90
May-22			366,916.47	$ 11,262,896.97	109,890.35	$ 5,166,458.68	$ 16,429,355.65
Jun-22			350,175.92	$ 10,518,548.04	63,910.23	$ 3,115,800.38	$ 13,583,670.96
Jul-22			301,204.95	$ 8,932,747.36	33,917.25	$ 1,645,347.40	$ 10,529,413.05
Aug-22			313,056.66	$ 9,541,612.85	17,553.49	$ 841,351.23	$ 10,382,964.08
Sep-22			363,404.50	$ 11,401,827.49	58,496.79	$ 2,698,650.21	$ 14,100,477.70
Oct-22			456,771.15	$ 13,490,974.69	89,873.45	$ 4,187,674.83	$ 17,678,649.52
Nov-22			520,187.11	$ 15,784,594.96	99,216.95	$ 4,491,208.90	$ 20,275,803.86
Dec-22			429,825.87	$ 13,875,252.48	47,946.35	$ 2,182,658.21	$ 16,057,910.69
Total-22			5,135,714.56	$ 156,014,557.80	1,070,246.02	$ 49,565,120.26	$ 205,480,318.89
Jan-23			393,539.81	$ 11,685,951.91	31,307.96	$ 1,193,237.63	$ 12,879,189.54
Feb-23			457,372.21	$ 12,714,269.78	105,822.35	$ 4,515,463.23	$ 17,229,733.01
Mar-23			401,518.34	$ 11,177,949.13	126,969.66	$ 5,145,929.23	$ 16,323,878.36
Apr-23			401,450.67	$ 11,239,143.01	233,339.64	$ 8,885,901.35	$ 20,125,044.36
May-23			356,283.30	$ 10,473,135.98	107,749.67	$ 4,332,169.82	$ 14,805,305.80
Jun-23			229,902.24	$ 6,547,246.80	25,986.97	$ 1,131,588.32	$ 7,678,835.12
Jul-23			227,960.97	$ 5,997,173.58	14,721.14	$ 620,226.20	$ 6,617,399.78
Aug-23			301,707.75	$ 8,590,910.10	40,692.28	$ 1,443,504.63	$ 10,034,414.73
Sep-23			292,808.25	$ 8,774,907.11	50,288.45	$ 1,817,959.89	$ 10,592,867.00
Oct-23			349,930.24	$ 10,155,505.00	157,767.04	$ 6,422,597.84	$ 16,578,102.84
Nov-23			406,121.36	$ 11,715,734.21	141,409.42	$ 5,708,258.93	$ 17,423,993.14
Dec-23			423,265.51	$ 12,255,617.97	72,952.92	$ 2,819,767.57	$ 15,075,385.54
Total-23			4,241,860.65	$ 121,327,544.58	1,109,007.47	$ 44,036,604.64	$ 165,364,149.22
Jan-24			383,644.55	$ 11,108,778.02	47,795.53	$ 2,254,689.27	$ 13,363,467.29
Feb-24			384,473.64	$ 10,793,881.34	113,601.92	$ 4,876,651.16	$ 15,670,532.50
Mar-24			437,376.69	$ 12,586,350.20	155,102.91	$ 6,430,104.06	$ 19,016,454.26
Apr-24			415,747.68	$ 11,444,758.63	254,803.14	$ 10,754,594.43	$ 22,199,353.06
May-24			369,513.96	$ 10,183,267.83	114,534.36	$ 4,740,964.90	$ 14,924,232.73
Jun-24			338,987.62	$ 9,448,978.75	77,713.51	$ 3,249,051.12	$ 12,698,029.87
Jul-24			230,601.03	$ 6,585,254.14	26,487.60	$ 997,192.36	$ 7,582,446.50
Aug-24			284,339.87	$ 7,831,133.08	49,436.60	$ 1,932,488.10	$ 9,763,621.18
Sep-24			308,802.80	$ 9,033,604.76	175,558.60	$ 7,252,089.06	$ 16,285,693.82
Oct-24			409,599.24	$ 11,455,676.63	154,204.55	$ 6,210,591.33	$ 17,666,267.96
Nov-24			369,971.25	$ 10,251,884.60	123,166.40	$ 5,218,216.92	$ 15,470,101.52
Dec-24			402,308.10	$ 11,405,907.28	67,560.81	$ 2,693,304.33	$ 14,099,211.61
Total-24			4,335,366.42	$ 122,129,475.26	1,359,965.93	$ 56,609,937.04	$ 178,739,412.30

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 3 (MISO)

Production Month	Date Paid: Delivered MWh	Date Paid: Lost MWh	Wind Production Delivered: MWh Delivered	Wind Production Delivered: Amount Xcel Energy Paid	Lost Production: Lost MWh	Lost Production: Amount Xcel Energy Paid	Total Xcel Energy Paid
Jan-22			421,262.70	$ 12,660,937.24	133,508.58	$ 6,145,798.49	$ 18,806,735.73
Feb-22			444,805.98	$ 12,491,211.87	108,559.97	$ 4,988,995.72	$ 17,480,207.59
Mar-22			449,872.63	$ 12,203,323.15	92,798.08	$ 4,318,981.66	$ 16,522,304.81
Apr-22			449,668.29	$ 12,480,199.83	214,574.54	$ 9,782,194.55	$ 22,262,394.38
May-22			331,572.70	$ 9,590,629.65	109,890.35	$ 5,166,458.68	$ 14,757,088.33
Jun-22			325,296.09	$ 9,173,049.08	63,910.23	$ 3,115,800.38	$ 12,288,849.46
Jul-22			281,795.31	$ 7,914,911.18	33,917.25	$ 1,645,347.40	$ 9,560,258.58
Aug-22			294,801.09	$ 8,576,613.16	17,553.49	$ 841,351.23	$ 9,417,964.39
Sep-22			330,882.88	$ 9,722,738.22	58,496.79	$ 2,698,650.21	$ 12,421,388.43
Oct-22			422,570.65	$ 11,865,164.82	89,873.45	$ 4,187,674.83	$ 16,052,839.65
Nov-22			403,573.57	$ 10,362,753.12	99,216.95	$ 4,491,208.90	$ 14,853,962.02
Dec-22			398,971.69	$ 12,150,842.70	47,946.35	$ 2,182,658.21	$ 14,333,500.91
Total-22			4,555,073.57	$ 129,192,374.02	1,070,246.02	$ 49,565,120.26	$ 178,757,494.28
Jan-23			300,505.52	$ 7,621,749.84	31,307.96	$ 1,193,237.63	$ 8,814,987.47
Feb-23			422,223.84	$ 10,826,162.18	105,822.35	$ 4,515,463.23	$ 15,341,625.41
Mar-23			369,946.99	$ 9,401,623.12	126,969.66	$ 5,145,929.23	$ 14,547,552.35
Apr-23			363,859.87	$ 9,149,165.33	233,339.64	$ 8,885,901.35	$ 18,035,066.68
May-23			307,407.89	$ 8,291,640.27	107,749.67	$ 4,332,169.82	$ 12,623,810.09
Jun-23			205,105.68	$ 5,435,189.30	25,986.97	$ 1,131,588.32	$ 6,566,777.62
Jul-23			178,833.06	$ 4,648,049.48	14,721.14	$ 620,226.20	$ 5,268,275.68
Aug-23			268,723.55	$ 7,159,598.34	40,692.28	$ 1,443,504.63	$ 8,603,102.97
Sep-23			257,892.62	$ 7,291,080.65	50,288.45	$ 1,817,959.89	$ 9,109,040.54
Oct-23			321,211.47	$ 8,591,181.45	157,767.04	$ 6,422,597.84	$ 15,013,779.29
Nov-23			374,994.07	$ 10,034,452.42	141,409.42	$ 5,708,258.93	$ 15,742,711.35
Dec-23			351,691.40	$ 10,153,037.71	72,952.92	$ 2,819,767.57	$ 12,972,805.28
Total-23			3,722,395.95	$ 98,602,930.09	1,109,007.47	$ 44,036,604.64	$ 142,639,534.73
Jan-24			358,885.38	$ 9,870,717.08	47,795.53	$ 2,254,689.27	$ 12,125,406.35
Feb-24			295,642.22	$ 8,070,136.35	113,601.92	$ 4,876,651.16	$ 12,946,787.51
Mar-24			326,546.19	$ 9,105,916.09	155,102.91	$ 6,430,104.06	$ 15,536,020.15
Apr-24			383,385.78	$ 9,727,944.33	254,803.14	$ 10,754,594.43	$ 20,482,538.76
May-24			344,243.04	$ 8,848,454.37	114,534.36	$ 4,740,964.90	$ 13,589,419.27
Jun-24			299,562.25	$ 7,799,661.84	77,713.51	$ 3,249,051.12	$ 11,048,712.96
Jul-24			203,240.57	$ 5,439,568.57	26,487.60	$ 997,192.36	$ 6,436,760.93
Aug-24			247,872.70	$ 6,343,095.70	49,436.60	$ 1,932,488.10	$ 8,275,583.80
Sep-24			260,518.10	$ 6,987,923.71	175,558.60	$ 7,252,089.06	$ 14,240,012.77
Oct-24			350,578.51	$ 9,006,617.41	154,204.55	$ 6,210,591.33	$ 15,217,208.74
Nov-24			323,761.40	$ 8,217,332.95	123,166.40	$ 5,218,216.92	$ 13,435,549.87
Dec-24			375,638.80	$ 10,047,540.84	67,560.81	$ 2,693,304.33	$ 12,740,845.17
Total-24			3,769,874.94	$ 99,464,909.24	1,359,965.93	$ 56,609,937.04	$ 156,074,846.28

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lake Benton I

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			Total
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Paid
Jan-22								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Northern Alternative Energy (NAE)

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Paid
Jan-22								
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Velva

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Paid
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Fenton (EnXco)

[PROTECTED DATA BEGINS

Production Month	Date Paid		Wind Production Delivered		Lost Production			Total Xcel Energy Paid
	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	
Jan-22								
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - MinnDakota (Formerly Ivanhoe)

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Xcel Energy Paid
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lincoln Heights Wind Holdings North*

[PROTECTED DATA BEGINS

Production Month	Date Paid		Wind Production Delivered		Lost Production			Total Xcel Energy Paid
	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	
Jan-22								
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PROTECTED DATA ENDS]

**Effective 7/1/16 Norgaard North changed name to Lincoln Heights Wind Holdings North LLC.*

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lincoln Heights Wind Holdings South*

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Xcel Energy Paid
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**Effective 7/1/16 Norgaard North changed name to Lincoln Heights Wind Holdings South LLC.*

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - JJN Windfarm, LLC.

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Xcel Energy Paid
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Ulik

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Xcel Energy Paid
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Ewington

Docket No. E002/AA-23-153
True-Up Report
Part C, Attachment 2

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Xcel Energy Paid
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Moraine II Wind LLC

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Xcel Energy Paid
Jan-22								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Prairie Rose

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Xcel Energy Paid
Jan-22								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Zephyr Wind LLC

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Xcel Energy Paid
Jan-22								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Big Blue Wind Farm

[PROTECTED DATA BEGINS

Production Month	Date Paid		Wind Production Delivered		Lost Production			Total Xcel Energy Paid
	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	
Jan-22								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Valley View Wind

[PROTECTED DATA BEGINS

Production Month	Date Paid		Wind Production Delivered		Lost Production			Total Xcel Energy Paid
	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	
Jan-22								
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Ridgewind Power Partners LLC

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Xcel Energy Paid
Jan-22								
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Grant County Wind LLC

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Xcel Energy Paid
Jan-22								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Adams Wind Generations

[PROTECTED DATA BEGINS

Production Month	Date Paid: Delivered MWh	Date Paid: Lost MWh	Wind Production Delivered: MWh Delivered	Wind Production Delivered: Amount Xcel Energy Paid	Lost Production: Lost MWh	Lost Production: Amount Xcel Energy Paid	Lost Production: Reason Codes	Total Xcel Energy Paid
Jan-22								
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Odell

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Xcel Energy Paid
Jan-22								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Woodstock Hills

[PROTECTED DATA BEGINS

Production Month	Date Paid		Wind Production Delivered		Lost Production			Total Xcel Energy Paid
	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	
Jan-22								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Cisco

[PROTECTED DATA BEGINS

Production Month	Date Paid: Delivered MWh	Date Paid: Lost MWh	Wind Production Delivered: MWh Delivered	Wind Production Delivered: Amount Xcel Energy Paid	Lost Production: Lost MWh	Lost Production: Amount Xcel Energy Paid	Lost Production: Reason Codes	Total Xcel Energy Paid
Jan-22								
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Crowned Ridge

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Xcel Energy Paid
Jan-22								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Glen Ullin

[PROTECTED DATA BEGINS

Production Month	Date Paid		Wind Production Delivered		Lost Production			Total Xcel Energy Paid
	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	
Jan-22								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Dakota Range III

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Xcel Energy Paid
Jan-22								
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PROTECTED DATA ENDS]

Curtailment Summary Report - Company Owned Facilities

2024 Reporting Period

Project	January		February		March		April		May	
	MWh Produced	MWh Curtailed	MWh Produced	MWh Curtailed	MWh Produced	MWh Curtailed	MWh Produced	MWh Curtailed	MWh Produced	MWh Curtailed
Blazing Star 1	70,120	359	70,936	138	85,955	282	93,760	2,873	78,605	219
Blazing Star 2	69,620	304	71,734	103	88,906	243	94,924	1,413	79,285	215
Border	56,900	55	43,531	44	56,542	172	61,813	88	50,330	62
Community Wind North	8,427	0	9,712	0	11,697	0	12,672	53	10,641	0
Courtenay	65,159	144	60,135	210	69,903	217	78,966	273	59,907	329
Crowned Ridge II	62,422	757	70,312	455	84,319	337	91,155	6,834	71,861	1,287
Dakota Range 1&2	79,817	447	82,226	1,290	103,135	1,642	124,036	2,098	91,846	2,709
Foxtail	45,356	2,704	43,955	7,819	42,964	23,420	55,799	14,478	56,324	1,177
Freeborn	61,794	424	76,183	1,384	83,409	6,081	95,026	1,705	67,530	1,803
Grand Meadow	26,146	2,511	36,202	20	40,593	18	44,925	348	30,401	41
Jeffers	15,974	146	17,724	97	20,362	45	20,200	1,092	16,829	113
Lake Benton II	32,671	51	34,102	4,462	48,142	137	44,430	3,774	38,179	2,230
Mower County	26,031	14	32,878	10	38,141	17	39,072	278	27,416	112
Noble	45,414	10,791	49,725	23,041	92,448	2,356	91,617	9,304	57,136	14,688
Northern Wind	24,734	1,592	31,020	3,218	42,204	551	42,189	4,379	31,995	3,598
Pleasant Valley	57,672	711	73,515	348	83,106	159	90,572	1,065	43,665	1,873
Rock Aetna	57,672	207	6,951	216	8,346	14	8,714	358	7,621	161
Sherco Solar I	0	0	0	0	0	0	0	0	0	0

Curtailment Summary Report - Company Owned Facilities

2024 Reporting Period

Project	June		July		August		September		October	
	MWh Produced	MWh Curtailed	MWh Produced	MWh Curtailed	MWh Produced	MWh Curtailed	MWh Produced	MWh Curtailed	MWh Produced	MWh Curtailed
Blazing Star 1	61,169	2,380	24,310	5,383	40,894	1,882	71,903	3,765	77,959	187
Blazing Star 2	61,315	764	26,304	4,907	41,089	1,601	72,430	3,329	79,363	221
Border	52,680	501	26,735	3,009	43,547	535	53,244	3,680	53,605	494
Community Wind North	8,510	0	5,648	5	7,414	20	10,200	13	10,860	3
Courtenay	62,017	254	34,080	131	50,458	210	65,647	217	63,290	280
Crowned Ridge II	63,192	527	46,271	182	58,862	5,063	53,310	28,694	85,987	780
Dakota Range 1&2	74,297	2,133	49,077	287	67,553	1,174	82,448	16,961	108,754	439
Foxtail	51,058	839	32,097	80	52,051	129	57,536	2,981	47,455	15,215
Freeborn	61,507	794	36,167	300	46,382	499	52,013	7,196	61,833	35,020
Grand Meadow	28,378	38	14,414	12	18,822	12	24,189	17	43,785	18
Jeffers	11,053	13	10,453	19	12,210	4	17,149	602	17,856	1,560
Lake Benton II	31,884	2,388	22,322	1,022	29,227	289	37,791	2,924	43,539	11
Mower County	23,799	85	12,867	26	17,620	78	22,170	73	39,426	29
Noble	54,471	6,579	36,064	137	39,223	1,098	67,562	690	83,822	106
Northern Wind	26,291	2,982	16,717	1,975	22,122	823	33,776	1,294	37,508	6
Pleasant Valley	58,361	275	35,645	126	45,261	135	59,228	143	86,658	143
Rock Aetna	6,279	137	3,986	101	5,038	45	7,211	93	8,584	0
Sherco Solar I	0	0	0	0	0	0	0	0	0	0

Curtailment Summary Report - Company Owned Facilities

2024 Reporting Period

Project	November		December		2024 Total	
	MWh Produced	MWh Curtailed	MWh Produced	MWh Curtailed	MWh Produced	MWh Curtailed
Blazing Star 1	66,245	1,040	73,813	164	815,670	18,674
Blazing Star 2	66,557	812	74,108	193	825,635	14,105
Border	54,660	67	59,547	67	613,134	8,773
Community Wind North	9,755	139	9,147	0	114,683	234
Courtenay	62,710	251	65,111	203	737,383	2,720
Crowned Ridge II	73,371	658	73,453	488	834,515	46,064
Dakota Range 1&2	90,751	397	84,062	525	1,038,002	30,102
Foxtail	49,859	148	50,238	736	584,693	69,725
Freeborn	54,469	32,196	53,635	18,888	749,948	106,290
Grand Meadow	37,645	17	32,771	208	378,271	3,261
Jeffers	17,087	828	17,570	205	194,467	4,725
Lake Benton II	36,927	1,045	38,281	25	437,496	18,356
Mower County	34,216	48	29,060	20	342,696	790
Noble	71,172	583	63,805	338	752,460	69,710
Northern Wind	30,459	46	30,595	36	369,610	20,500
Pleasant Valley	73,352	74	62,179	1,288	769,214	6,340
Rock Aetna	6,877	6	6,927	0	82,123	1,337
Sherco Solar I	15,287	0	7,536	0	22,823	0

Company-Owned Wind Capacity Factors

Capacity Factors based on:	**Assumed at Acquisition**	**Actual Generation**				**Actual Generation + Curtailment Estimate**			
Wind Farm Name	**[PROTECTED DATA BEGINS**	**2021**	**2022**	**2023**	**2024**	**2021**	**2022**	**2023**	**2024**
Blazing Star 1		46.0	52.2	46.1	46.5	46.5	52.6	46.5	47.6
Blazing Star 2		42.3	51.1	46.6	47.3	43.1	51.7	46.9	48.1
Borders		48.3	50.6	44.4	47.3	48.3	51.4	44.7	48.2
Community Wind North		45.9	52.4	47.3	49.5	46.3	52.4	47.3	49.6
Courtenay		42.5	46.6	39.6	42.0	43.0	46.9	39.9	42.1
Crowned Ridge 2		47.0	50.4	44.3	45.7	49.9	55.6	48.6	48.3
Dakota Range 1 & 2			43.5	36.0	39.6		45.9	37.6	40.7
Foxtail		47.3	42.4	44.0	44.5	50.7	51.3	48.7	49.8
Freeborn			45.1	43.1	42.8		50.7	43.5	48.8
Grand Meadow		24.6	29.1			31.8	30.7		
Grand Meadow Repower (Ben Fowke)				37.2	43.3			38.3	43.7
Jeffers		45.0	54.3	49.8	50.4	47.5	54.9	49.9	51.5
Lake Benton 2		50.3	51.8	49.1	49.7	52.4	52.3	51.0	51.8
Mower			40.8	36.5	39.5		41.2	36.7	39.6
Nobles		19.6	23.9			37.5	38.7		
Nobles Repower				42.6	42.9			44.2	46.9
Northern Wind				39.9	46.0			41.9	48.6
Pleasant Valley		40.4	49.5	42.6	44.1	42.7	49.6	43.0	44.4
Rock Aetna				45.3	58.5			46.3	59.3
	PROTECTED DATA ENDS]								

Note: The capacity factor (CF) provided is what Xcel Energy considers the "Design" CF, which uses the site interconnection injection limit in the denominator as opposed to the gross turbine capacity or the net capacity at the point of interconnect. Since we provided similar data in our response to Information Request No. DOC-11 in Docket No. E002/AA-23-153 on May 26, 2023, the actual values from past periods have been updated to match this methodology.

Plant Operations and Maintenance

The Commission's March 15, 2010 ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND SETTING FURTHER REQUIREMENTS in Docket No. E999/AA-08-995 and April 6, 2012 ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS in Docket Nos. E999/AA-09-961 and E999/AA-10-884 require utilities to provide additional details about plant planned and unplanned outages and actions taken to prevent future outages. We provide the information below.

A. Unplanned and Planned Outages

Part C, Attachments 4a and 4b provide the following details for each unplanned and planned outage during the 2024 Fuel Clause Adjustment (FCA) reporting year:[1]

Planned Outages
- Primary reason for the planned outage; and
- Description of the work performed during the planned outage.

Unplanned Outages
- Description of the equipment that resulted in the forced outage;
- Description of the equipment failure;
- Change in energy costs resulting from the outage;
- Failure history during the reporting period; and
- Steps taken to alleviate reoccurrence of the outage.

In addition, Part C, Attachments 5a and 5b provide a comparison of forecasted outage costs by unit to actual outages experienced, both unplanned and planned.

B. Contractor Performance

Xcel Energy continues to prioritize its careful oversight of contractor and supplier performance. The Company focuses on three areas, as discussed below.

[1] The information is presented in Minnesota Power's Attachment A outage report format, as specified by the Department in its June 5, 2013, review of utilities' 2011-2012 AAA Reports.

First, Xcel Energy uses a quality assurance and control protocol for the majority of our contracts. This proactive approach is designed to draw attention to the required quality steps Xcel Energy expects each contractor to follow.

Second, Xcel Energy has awarded several master agreements with companies that consistently exceed others in technology, quality, and contract management (including following the Scope of Work).

Third, Xcel Energy has invested time and resources to develop more detailed Scopes of Work. Scopes of Work are included in the purchase order and set the expectation for the work. Detailed Scopes of Work yield an acceptable work product, favorable project scheduling, and reduced unit outage extensions.

In the event problems arise with services, equipment, and/or materials provided by a vendor/supplier, the Company utilizes a Non-Conformance Reporting Process to correct deficiencies. In addition, special conditions that hold suppliers and contractors accountable for quality management are placed in all contracts. Remedies for problems that adversely affect generating plant performance can include the direct costs of re-work, including labor and/or materials.

The Company strives to contract for generation plant repair and maintenance services with parties who have a history of performing work safely, reliably, and in a timely manner.

C. Operational Strategies

As stated in prior Fuel Clause Adjustment Reports, we have operational improvement initiatives at work under the Generation Operating Model Framework. The Generation Operating Model Framework focus remains on continuous improvement, and it has resulted in the Company's formation of the Performance Optimization department. This department is comprised of (1) Reliability Engineering, which provides on-site engineering support and maintains design basis; (2) Fleet Engineering, which develops and implements asset and equipment strategies consistently across the generating facility fleet; and (3) Analytics and Practices, which provides remote monitoring to correct issues prior to failure.

Generation's operational excellence initiative includes gas fleet excellence for the combined cycle plants High Bridge, Black Dog, and Riverside and some simple cycle gas plants. The operational excellence initiative also includes asset predictive maintenance strategies, legacy plant reliability risk reduction, staffing proficiency, procedures for performance, unit resiliency, and the implementation of GE Asset Performance Management (GE-APM) software. This software leverages technology to effectively enable Asset Performance Management. It consolidates and analyzes data from a variety of sources to optimize the cost, risk, and reliability of selected generation equipment. Outputs of GE-APM include optimized equipment maintenance strategies and the development of Intelligent Asset Health and Operational Risk analytical models and dashboards.

D. Sherco U1, King U1, Sherco U3

Equipment maintenance at Sherco U1, King U1, and Sherco U3 continues to be prudently managed, given the upcoming retirement dates of 2026, 2028, and 2030, respectively. King continues seasonal operations. All testing and maintenance required by regulation is performed. Event assessments targeting root cause are performed for Sherco U3 when the load output of the unit is limited. Plant management has identified the equipment and conditions that will result in unplanned power reduction and prioritizes maintenance to prevent their occurrence. Planned and unplanned outages will continue to be reported in the present docket.

E. Generation Maintenance Costs

The Commission's February 6, 2008 ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS, REQUIRING FURTHER FILINGS, AND AMENDING ORDER OF DECEMBER 20, 2006 ON PASSING MISO DAY 2 COSTS THROUGH FUEL CLAUSE in Docket Nos. E,G999/AA-06-1208 and E002/M-04-1970 *et al.* requires utilities to provide a comparison of the actual expenses pertaining to maintenance of generation plants to the generation maintenance budget from the utility's most recent rate case. We provide this information as Part C, Attachment 6.

Protected Data is Shaded

[PROTECTED DATA BEGINS

	Unit	Outage Category	Primary Reason for Unplanned Outage	Outage Dates Start	End	Duration (Days)	Equipment that resulted in the forced outage	Description of Equipment Failure	Change in Energy Costs ($s	Failure History During Reporting Period	Steps Taken to Alleviate Reoccurrence
1	CCRiverside1	Forced	Unit 9 Bypass valve went open due to DVC & wiring issues	1/4/2024	1/8/2024	4	High Pressure Steam Bypass Valve for Unit 9	The controller for the valve position did not control the position of the valve. The valve opened when it was not supposed to which caused the unit to trip off line.		No other failures of this valve and controller during the reporting period.	DVC (Digital Valve Controller) was replaced and valve control was restored.
2	CCRiverside1	Forced	Repair steam leak on Main Stem Drain Line for Unit 7.	4/24/2024	4/27/2024	3	Unit 7 Steam Turbine Main Steam drain line developed a steam leak	Steam erosion, due to foreign material stuck in drain line, developed a hole in the line resulting in a main steam leak.		No other similar failures during the reporting period.	Foreign material was removed and the affected portion of the drain line piping was replaced.
3	CCRiverside1	Forced	Main Drain Line steam leak on steam turbine. Unit off line for repairs.	10/30/2024	10/31/2024	2	Drain Line Isolation Valve leak	Steam erosion of valve body resulted in pin hole leak on downstream side of valve body; internal erosion.		No other similar failures during the reporting period.	Replaced valve. Similar valve on other side of steam turbine will be preemptively replaced during next outage.
4	CCRiverside2	Forced	Repair steam leak on Main Stem Drain Line for Unit 7.	4/24/2024	4/29/2024	5	Unit 7 Steam Turbine Main Steam drain line developed a steam leak	Steam erosion, due to foreign material stuck in drain line, developed a hole in the line resulting in a main steam leak.		No other similar failures during the reporting period.	Foreign material was removed and the affected portion of the drain line piping was replaced.
5	CCRiverside2	Forced	Repair blown fuse on combustion can end cap 13.	5/12/2024	5/14/2024	3	#13 Fuel nozzle end cap failed.	Flame holding combustion event caused a portion of the fuel nozzle end cap to fail due to incorrect firing.		No other blown fuse events occurred during this reporting period.	End cap was replaced. Combustion tuning controls were modified to provide additional margin to prevent a future flame holding event.
6	CCRiverside2	Forced	Main Steam Drain Line steam leak on steam turbine. Unit off line for repairs.	10/30/2024	10/31/2024	2	Drain Line Isolation Valve leak	Steam erosion of valve body resulted in pin hole leak on downstream side of valve body; internal erosion.		No other similar failures during the reporting period.	Replaced valve. Similar valve on other side of steam turbine will be preemptively replaced during next outage.
7	CCRiverside2	Forced	Derate required to manage combustion issues and NOX limits	11/19/2024	11/20/2024	1	U10 Combustion hardware	A fuel nozzle in the combustion turbine failed, but allowed extended derated operation during a heat spell. The unit was taken offline soon after the heat spell to replace the nozzle.		Similar event happened on 5/12 during the reporting period	Failure mechanism is still being determined with OEM.
8	CCRiverside2	Forced	Repair blown fuse on combustion end cap 6	11/20/2024	11/22/2024	1	#6 Fuel nozzle end cap failed.	Flame holding combustion event caused a fuel nozzle failure		Similar event happened on 5/12 during the reporting period	Failure mechanism is still being determined with OEM.
9	King_G1	Forced	D1 (Unplanned (forced) Derating - Immediate) - Boiler Feed Pump	7/10/2024	7/12/2024	2	13 Boiler Feed Pump (BFP)	Failed driver caused high speed event and had to perform post event inspection		Pump issues in 2022 but different failure mechanism	Driver was replaced and post maintenance testing plan created
10	King_G1	Forced	U2 (Unplanned (forced) Outage - Delayed) Burner Wind Boxes and Dampers	7/16/2024	7/20/2024	4	Boiler wind box	Crack in windbox resulting in air leak		None	Repair was made in the windbox, during seasonal down time inspection and repairs to windbox will be
11	King_G1	Forced	U1 (Unplanned (forced) Outage - Immediate) - Cyclone Furnace \Hydrogen Coolers	7/23/2024	7/31/2024	8	Generator Hydrogen cooler	Failed gasket on hydrogen cooler after over pressurization of condensate system resulting in leaking condensate into hydrogen side of coolers, during repair of the gaskets generator blower blades found to be loose		None	Gaskets repaired, coolers tested for leaks, redundant alarms put in place to prevent over pressurization, the suspension system for ash blower blades was also replaced at this time.
12	King_G1	Forced	U1 (Unplanned (forced) Outage - Immediate) - Hydrogen Coolers	8/1/2024	8/10/2024	10	Generator Hydrogen cooler	Failed gasket on hydrogen cooler after over pressurization of condensate system resulting in leaking condensate into hydrogen side of coolers, during repair of the gaskets generator blower blades found to be loose		Part of July 2024 Event	Gaskets repaired, coolers tested for leaks, redundant alarms put in place to prevent over pressurization, the suspension system for hydrogen blower blades was also replaced at this time.
13	King_G1	Forced	U1 (unplanned forced outage immediate) - Vibration Of The Turbine Generator Unit -High Vibs on generator	12/11/2024	12/15/2024	4	Generator seal	The outer seal on #7 generator bearing had to tight of a tolerance causing a rub on the shaft causing high vibrations		None	The seal was adjusted by plant maintenance to allow for the proper clearance and eliminating the rub.
14	Monticello_1	Forced	Shutdown required due to I&C technician adjusted incorrect component while performing surveillance testing.	2/28/2024	2/29/2024	2	System that signals control rods to insert in order to shut down the reactor received signal.	During testing of the "Anticipated Transient Without Scram (ATWS)" system, a technician adjusted the incorrect component, which resulted in a signal to the control rods to insert into the reactor in order to shut it down.		None	1) Included procedural steps to ensure various tools are used, such as flagging correct components to eliminate risk of being on incorrect component. Constructed physical barriers to be used to prevent inadvertent actuation. 2) Performed leadership training for event and lessons learned review.
15	Monticello_1	Forced	(same as above) Shutdown required due to I&C technician adjusted incorrect component while performing surveillance testing.	3/1/2024	3/3/2024	2	System that signals control rods to insert in order to shut down the reactor received signal.	During testing of the "Anticipated Transient Without Scram (ATWS)" system, a technician adjusted the incorrect component, which resulted in a signal to the control rods to insert into the reactor in order to shut it down.		None	1) Included procedural steps to ensure various tools are used, such as flagging correct components to eliminate risk of being on incorrect component. Constructed physical barriers to be used to prevent inadvertent actuation. 2) Performed leadership training for event and lessons learned review.
16	Monticello_1	Forced	Forced outage to repair reactor safety relief valve	3/27/2024	3/31/2024	5	Reactor vessel safety relief valve	A reactor vessel safety relief valve showed a slow rise in temperature following the ATWS forced outage described above. This indicated seat leakage and the decision was made to shut down the unit and replace the valve.		None	Replaced valve
17	PR_ISLD_1	Forced	Repair Feedwater System Line Steam Leak	2/9/2024	2/12/2024	4	Valve on feedwater line that feeds the steam generators	Feedwater line valve identified to be leaking past the valve seat and pipe plug.		None	Replaced the valve.
18	PR_ISLD_1	Forced	Derate to repair cracked weld on Circulating Water System following scheduled Circulating Water Box cleaning	6/14/2024	6/19/2024	5	Flange/vent area welds on circulating water pump casing	Flange/vent area welds on circulating water pump casing leaking by.		None	Repaired weld leak.
19	PR_ISLD_2	Forced	The bypass valve for the full-flow filter demineralizer failed to open while valving in the system.	3/3/2024	3/8/2024	5	A control valve on the filter demineralizer system	This was found while increasing power coming out of the planned 2R33 refueling outage. A control valve failed to perform its required automatic function which resulted in a loss of suction to the main feedwater pump and therefore a turbine trip.		None	Replaced the valve actuator.
20	PR_ISLD_2	Forced	Repairs to RX Protection Logic Equip 2N41	3/16/2024	3/17/2024	1	deaerator Tank	A potentiometer associated with the power range detector spiked high during the testing, which caused a flux rate trip signal.		None	Replaced a potentiometer.
21	PR_ISLD_2	Forced	Flux Rate trip due to Rod Control Bank C dropping during required surveillance testing	10/29/2024	10/31/2024	3	Control rods dropped into reactor core	The rod control system, which is used to control reactor power and shut down the reactor quickly if rods drop into the core, unexpectedly dropped into the core. This was due to card cage back plane connectors being out of tolerance, increasing potential for spurious system operation.		None	1) Vendor supported onsite troubleshooting of the system. 2) Card pins were reformed. 3) With Unit 1 in a planned refueling outage, a decision as made to do the same activity on the Unit 1 rod control system cards.
22	PR_ISLD_2	Forced	(Same as above) Flux Rate trip due to Rod Control Bank C dropping during required surveillance testing	11/1/2024	11/10/2024	9	Control rods dropped into reactor core	The rod control system, which is used to control reactor power and shut down the reactor quickly if rods drop into the core, unexpectedly dropped rods into the core. This was due to card cage back plane connectors being out of tolerance, increasing potential for spurious system operation.		None	1) Vendor supported onsite troubleshooting of the system. 2) Card pins were reformed. 3) With Unit 1 in a planned refueling outage, a decision as made to do the same activity on the Unit 1 rod control system cards.
23	SHERC3	Forced	Boiler Feed Pump Turbine developed an oil leak which requires the to be removed from service to identify and repair.	1/3/2024	1/5/2024	2	Boiler Feed Pump Turbine	An oil leak developed on 32 BFPT front standard which leaked on to lagging causing a smoldering fire in the lagging. BFPT was removed from service until front standard leak could be repaired.		None	Front standard bolts were tightened and lagging repaired to prevent a fire recurrence.
24	SHERC3	Forced	Derate due to 3 coal mills out of service.	4/15/2024	4/19/2024	4	301, 302 and 308 Coal Mills	301 Coal mill was out of service due to a failed gearbox, 302 coal mill removed due to broken rotating throat assembly, and 308 coal mill removed to repair a coal leak in a transport line.		Derates due to having more than two coal mills out of service preventing the unit from making full load capability. Similar occurrence on 5/1/24..	Repaired the coal leak on 308 mill to restore redundancy. 302 rotating throat was repaired and the mill returned to service. 301 Coal mill turned over to contractor for a major overhaul including gearbox replacement.
25	SHERC3	Forced	Mills 310 mill has a plugged feed tube from the feeder to the mill, 309 mill lost the oil pump, 306 and 301 mills are held for repairs.	5/1/2024	5/2/2024	2	301, 306, 309 and 310 Coal Mills	301 Coal mill was out of service due to a failed gearbox, 306 coal mill removed due to a tensioning rod failure, 309 mill removed due to failed lube oil pump and 310 mill developed a plug in the outlet from the feeder to the coal mill due to wet coal.		Derates due to having more than two coal mills out of service preventing the unit from making full load capability. Similar occurrence on 4/15/24..	Unplugged 310 coal mill feeder with General Plant Helper support and repaired 309 coal mill lube oil pump to restore redundancy.
26	SHERC3	Forced	Unit 3 is in a derated condition due to concerns over increased temperatures on generator breaker 8N27 (C) disconnect.	5/2/2024	5/6/2024	4	Substation Disconnect	With Bus 2 out of service in the substation the only path for generator output on unit 3 was through 8N27 to Bus 1. Substation Construction noted high temperatures on this disconnect so the unit was derated to a level that maintained disconnect temperatures in an acceptable range until a unit outage could be taken to perform maintenance on the disconnect.		None	Outage was taken to allow substation breaker crew to inspect and repair the disconnect.
27	SHERC3	Forced	Failure of 6B bend pulley with 3 coal crusher motor out of service resulted in both paths of coal supply to unit 3 being unavailable.	7/5/2024	7/8/2024	2	Coal Supply	With 4 coal crusher motor being out of service, 6B belt was the sole supply of coal to unit 3. A failure of the 6B bend pulley resulted in no coal supply to the unit resulting in a forced outage until the pulley could be replaced.		None	Replaced 6B bend pulley to restore coal supply to the unit.

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	Unit	Outage Category	Primary Reason for Unplanned Outage	Outage Dates Start	End	Duration (Days)	Equipment that resulted in the forced outage	Description of Equipment Failure	Change in Energy Costs ($s	Failure History During Reporting Period	Steps Taken to Alleviate Reoccurrence
28	SHERC3	Forced	Unable to complete startup due to high vibrations on bearings 5 and 6.	7/8/2024	7/11/2024	3	Turbine Generator	During startup a temperature differential in the Low Pressure A hood resulted in high vibrations on bearings 5 and 6 during startup. Startup was aborted, cause of the temperature differential was repaired and the unit was allowed to cool to remove the temperature differential.		None	Increased monitoring of low pressure turbine hood temperatures to ensure an unacceptable temperature differential does not occur. Adjusted steam seal pressure to ensure the temperature differential does not occur in the future.
29	SHERC3	Forced	Multiple derates due to only having 7 or fewer coal mills available.	8/1/2024	8/4/2024	3	Coal Mills	301 Coal Mill was removed from service for a major overhaul. 303 mill developed a leak in the Primary Air duct door requiring mill to be removed from service to repair. 306 coal mill would not get a start permissive requiring troubleshooting.		Derates due to having more than two coal mills out of service preventing the unit from making full load capability. Similar occurrence on 4/15/24, 5/1/24, and 12/13/24 for Unit 3. Similar Occurrence on 9/19/24, 12/12/24 and 12/18/24 on Unit 1.	Repaired 303 and 306 mills to restore minimum number of mills for full load operation.
30	SHERC3	Forced	Unit 3 derate due to 33 BFP HP stop valve being stuck open and not able to close on BFP trip.	8/14/2024	8/27/2024	13	Boiler Feed Pump Turbine	33 Boiler Feed Pump Turbine High Pressure Stop valve stuck open. This is a safety feature for turbine protection so the BFPT was removed from service until a repair could be performed.		Similar occurrence on 1/3/24 and 8/27/24.	Removed unit from service to repair stop valve. Stop valve replaced and testing completed to restore to full power operation.
31	SHERC3	Forced	due to 33 BFP HP stop valve stuck open, unable to make steam flow demand because of high condenser back pressure and a boiler tube	8/27/2024	8/31/2024	4	Boiler Feed Pump Turbine	33 Boiler Feed Pump Turbine High Pressure Stop valve stuck open. This is a safety feature for turbine protection so the BFPT was removed from service until a repair could be performed.		Similar occurrence on 1/3/24 and 8/14/24.	Removed unit from service to repair stop valve. Stop valve replaced and testing completed to restore to full power operation.
32	SHERC3	Forced	Unable to make steam flow demand because of high condenser back pressure and a boiler tube	9/1/2024	9/2/2024	1	Main Condenser	Z-Ball system for online condenser cleaning became inoperable leading to condenser fouling. Required entry into Circ Water system to repair the Z-Ball system and clean the fouled condenser tubing. Unit derated until it could be taken offline for cleaning.		Similar occurrence on 9/7/24 and 10/1/24.	Derated unit until the unit could be removed from service to clean the main condenser tubes and repair the Z-Ball system for online condenser cleaning.
33	SHERC3	Forced	Unable to make steam flow demand because of high condenser back pressure and a boiler tube	9/7/2024	9/23/2024	16	Main Condenser	Z-Ball system for online condenser cleaning became inoperable leading to condenser fouling. Required entry into Circ Water system to repair the Z-Ball system and clean the fouled condenser tubing. Unit derated until it could be taken offline for cleaning.		Similar occurrence on 9/1/24 and 10/1/24.	Derated unit until the unit could be removed from service to clean the main condenser tubes and repair the Z-Ball system for online condenser cleaning.
34	SHERC3	Forced	Require unit offline to repair tube leak in superheat bundle.	9/23/2024	9/30/2024	8	Boiler Tubing	Tube leak in the superheat section of the boiler.		Similar occurrence on 9/ 9/29/24, 10/1/24, and 12/23/24 on Unit 1.	Unit removed from service and tube leak was repaired.
35	SHERC3	Forced	Unable to make steam flow demand because of high condenser back pressure	10/1/2024	10/11/2024	11	Main Condenser	Z-Ball system for online condenser cleaning became inoperable leading to condenser fouling. Required entry into Circ Water system to repair the Z-Ball system and clean the fouled condenser tubing. Unit taken offline for cleaning.		Similar occurrence on 9/1/24 and 9/7/24.	Removed from service to clean the main condenser tubes and repair the Z-Ball system for online condenser cleaning.
36	SHERC3	Forced	U3 is derated to 750 MW net. There are three coal mills out of service. 310 mill out for a major, 308 mill out for major, 307 mill out for mill motor replacement.	12/13/2024	12/17/2024	4	Coal Mills	308 and 310 Coal Mills removed from service for major overhaul. 307 coal mill had a motor failure which required mill to be removed from service to replace the motor.		Derates due to having more than two coal mills out of service preventing the unit from making full load capability. Similar occurrence on 4/15/24, 5/1/24, and 8/1/24 for Unit 3. Similar Occurrence on 9/19/24, 12/12/24 and 12/18/24 on Unit 1.	Replaced 307 coal mill motor to restore minimum number of mills for full load operation.
37	SHERCO_G1	Forced	Derate due to scrubber module poor performance and need to maintain environmental opacity limits.	1/1/2024	1/12/2024	11	Scrubber Modules	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 1/22/2024, 2/20/2024, 5/1/2024, 6/1/2024, 6/20/2024, 6/28/2024, and 7/17/2024. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.
38	SHERCO_G1	Forced	Unit 1 derated due to maintain average air preheater gas inlet temp 800 degrees and air preheater gas outlet temps less than 350 degrees.	1/13/2024	1/22/2024	9	Boiler Draft	Fouling in the backpass of the unit resulted in the need for a derate to maintain furnace temperatures within their design limits.		Similar occurrence on 2/1/24	Boiler was explosively cleaned to remove slag buildup in the backpass and, following the outage, a contractor was brought in to tune the boiler to improve unit performance.
39	SHERCO_G1	Forced	Need to Derate to maintain environmental regulation limits for opacity, modules in poor shape to remove particulate.	1/22/2024	1/31/2024	10	Scrubber Modules	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 1/1/2024, 2/20/2024, 5/1/2024, 6/1/2024, 6/20/2024, 6/28/2024, and 7/17/2024. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.
40	SHERCO_G1	Forced	Derated to maintain average air preheater gas inlet temp 800 degrees and outlet temps less than 350 degrees.	2/1/2024	2/20/2024	19	Boiler Draft	Fouling in the backpass of the unit resulted in the need for a derate to maintain furnace temperatures within their design limits.		Similar occurrence on 1/13/24	Boiler was explosively cleaned to remove slag buildup in the backpass and, following the outage, a contractor was brought in to tune the boiler to improve unit performance.
41	SHERCO_G1	Forced	9 of 12 modules. 102, 106, and 107 modules OOS for major cleans, maintains environmental margin limits.	2/20/2024	2/24/2024	4	Scrubber Modules	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 1/1/2024, 1/22/2024, 5/1/2024, 6/1/2024, 6/20/2024, 6/28/2024, and 7/17/2024. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.
42	SHERCO_G1	Forced	Derate due to scrubber modules out of service with 8 available. Require 10 modules to maintain full load capability	5/1/2024	5/31/2024	31	Scrubber Modules	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 1/1/2024, 1/22/2024, 2/20/2024, 6/1/2024, 6/20/2024, 6/28/2024, and 7/17/2024. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.
43	SHERCO_G1	Forced	Derate due to scrubber modules out of service with 8 available. Require 10 modules to maintain full load capability	6/1/2024	6/19/2024	18	Scrubber Modules	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 1/1/2024, 1/22/2024, 2/20/2024, 5/1/2024,6/20/2024, 6/28/2024, and 7/17/2024. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.
44	SHERCO_G1	Forced	Derate for module flushing , 108 module out for major, 112 module hole in expansion joint. Unit load reduction will maintain environmental margins.	6/20/2024	6/28/2024	8	Scrubber Modules	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 1/1/2024, 1/22/2024, 2/20/2024, 5/1/2024, 6/1/2024, 6/28/2024, and 7/17/2024. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.
45	SHERCO_G1	Forced	Poor scrubber module performance. Unable to make full load with less than 11 modules in service without exceeding environmental opacity limits.	6/28/2024	6/30/2024	3	Scrubber Modules	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 1/1/2024, 1/22/2024, 2/20/2024, 5/1/2024, 6/1/2024, 6/20/2024, and 7/17/2024. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.
46	SHERCO_G1	Forced	14 ID fan inlet damper had a vane break free and is freewheeling. Derate to remove 14 ID fan.	7/1/2024	7/11/2024	11	14 Induced Draft Fan	One of the damper blades broke loose of the actuator and commenced freewheeling resulting in higher vibrations on the ID fan. Fan removed from service until blade could be reattached.		None	Build scaffolding, removed lagging and repaired the weld on the broken blade to return the ID to service.
47	SHERCO_G1	Forced	Unit went into a swing. HP Heaters bypassed on high level. Extraction Block to 17 HP heater did not close causing channel relief valve to lift. Relief valve must be replaced.	7/11/2024	7/17/2024	5	17 High Pressure Heater	Relief valve lifted due to high pressure in 17 HP heater during the boiler swing and did not reset requiring heater string to be removed from service to replace the valve.		None	Obtained a replacement relief valve, replaced the valve and restored the heater string to service.

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	Unit	Outage Category	Primary Reason for Unplanned Outage	Outage Dates Start	Outage Dates End	Duration (Days)	Equipment that resulted in the forced outage	Description of Equipment Failure	Change in Energy Costs ($s	Failure History During Reporting Period	Steps Taken to Alleviate Reoccurrence
48	SHERCO_G1	Forced	Unit derated due to scrubber module performance. Unable to make full load with less than 11 modules in service without exceeding environmental opacity limits.	7/17/2024	7/24/2024	7	Scrubber Modules	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 1/1/2024, 1/22/2024, 2/20/2024, 5/1/2024, 6/1/2024, 6/20/2024, and 6/28/2024. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.
49	SHERCO_G1	Forced	9656 - Other stack or exhaust emissions testing - fossil	7/24/2024	7/26/2024	2	Boiler	Smartburn on site to conduct environmental permit required MATS tuning. Required a stable load at a reduced level due to boiler swings at the top of the load rang until tuning could be completed.		None	Completed boiler MATS tuning which eliminated the load swings permitting full power operation.
50	SHERCO_G1	Forced	Unit 1 derated to 650 mws net because of two modules out in the same row, high scrubber dp, O2 swings, and high opacity.	8/1/2024	8/7/2024	6	Scrubber Modules	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 1/1/2024, 1/22/2024, 2/20/2024, 5/1/2024, 6/1/2024, 6/20/2024, 6/28/2024, 8/10/2024, 8/28/2024, 9/1/2024, 9/15/2024. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.
51	SHERCO_G1	Forced	Require unit offline to repair failed super heat relief valve.	8/7/2024	8/10/2024	3	High Pressure Relief Valve	During normal operation, a plant transient resulted in one of the boiler relief valves lifting. Unit was derated and throttle pressure reduced to reset the relief valve until the unit could be removed from service for replacement.		Similar occurrence on 10/15/24	Replaced relief valve.
52	SHERCO_G1	Forced	Unit 1 derated to 650 mws net because of two modules out in the same row, high scrubber dp, O2 swings, and high opacity.	8/10/2024	8/24/2024	14	Scrubber Modules	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 1/1/2024, 1/22/2024, 2/20/2024, 5/1/2024, 6/1/2024, 6/20/2024, 6/28/2024, 8/1/2024, 8/28/2024, 9/1/2024, 9/15/2024. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.
53	SHERCO_G1	Forced	Require unit offline due to inability to isolate bottom ash water from leaking vault which is leading to environmental spills.	8/24/2024	8/28/2024	4	Discharge Piping	Discharge piping from unit 1 developed a leak in the underground piping. Required unit offline to isolate water sources to this piping so entry into the trench for piping replacement could be performed.		None	Replaced piping to prevent future failures.
54	SHERCO_G1	Forced	Unit 1 Derated to 600 MWn to maintain environmental margins. 110 module out for major clean, one module out for flushing, then one module eventually out for General clean.	8/28/2024	8/31/2024	4	Scrubber Modules	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 1/1/2024, 1/22/2024, 2/20/2024, 5/1/2024, 6/1/2024, 6/20/2024, 6/28/2024, 8/1/2024, 8/10/2024, 9/1/2024, 9/15/2024. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.
55	SHERCO_G1	Forced	Derate to maintain environmental margins. 110 module out for major clean, one module out for flushing, then one module eventually out for General clean.	9/1/2024	9/4/2024	3	Scrubber Modules	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 1/1/2024, 1/22/2024, 2/20/2024, 5/1/2024, 6/1/2024, 6/20/2024, 6/28/2024, 8/1/2024, 8/10/2024, 8/28/2024, 9/15/2024. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.
56	SHERCO_G1	Forced	With the loss of 12 feeder in the cascades unit is limited to amount of coal mills until repairs are made.	9/4/2024	9/6/2024	3	Coal Feeder	Failure of tail pulley resulted in loss of coal supply to the 3 unit 1 west coal mills. Unit derated until coal supply restored.		None	Replaced tail pulley on 12 feeder to restore coal supply to the west unit 1 coal silos.
57	SHERCO_G1	Forced	Derate necessary to complete scrubber module high voltage cleans. High voltage cleans will require as many as 3 modules out of service at one time.	9/15/2024	9/18/2024	4	Scrubber Modules	More than 2 modules removed from service for major clean and/or repairs. Additional modules out of service for daily flushing and general cleans. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 1/1/2024, 1/22/2024, 2/20/2024, 5/1/2024, 6/1/2024, 6/20/2024, 6/28/2024, 8/1/2024, 8/10/2024, 8/28/2024, 9/1/2024. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module has decreased to approximately once a year from once every 8 months. This has caused modules to be dirtier than in previous years resulting in longer cleaning cycles. This has necessitated taking 2 modules out of service at a time for major cleans requiring derates to perform additional module general cleans on their weekly schedule as well as daily module flushing.
58	SHERCO_G1	Forced	Two Coal Mills OOS: 12 mill interior repairs and 16 mill to clear pyrite chute and inspect mill interior. Further 3 modules OOS Derate necessary to complete scrubber	9/19/2024	9/23/2024	4	Coal Mills	12 coal mill removed from service due to internal damage. 16 mill had metal stick in the pyrite hopper requiring entry to remove.		Derates due to having more than one coal mill out of service preventing the unit from making full load capability. Similar occurrence on 4/15/24, 5/1/24, 8/1/24, and 12/13/24 for Unit 3. Similar Occurrence on 12/12/24 and 12/18/24 on Unit 1.	Entered 16 coal mill to remove stuck metal in pyrite hopper to restore minimum number of mills for full load operation.
59	SHERCO_G1	Forced	Tube Leak has emerged and we need to stay online until Unit 3 is able to come online and we are able to come offline to fix it.	9/29/2024	9/30/2024	2	Boiler Tubing	Tube leak in the water wall section of the boiler.		Similar occurrence on 9/23/24 on Unit 3 and 10/1/24 and 12/23/24 on Unit 1.	Derated unit to allow unit to stay online and minimize tube leak damage until unit could be removed from service to enter the boiler and repair the leak.
60	SHERCO_G1	Forced	Tube Leak has emerged waiting to come off line for repairs	10/1/2024	10/7/2024	6	Boiler Tubing	Tube leak in the superheat section of the boiler.		Similar occurrence on 9/23/24 on Unit 3 and 9/29/24 and 12/23/24 on Unit 1.	Derated unit to allow unit to stay online and minimize tube leak damage until unit could be removed from service to enter the boiler and repair the leak.
61	SHERCO_G1	Forced	Unit 1 derated to 540 mws net until 11 ID fan is repaired.	10/11/2024	10/15/2024	4	11 Induced Draft Fan	11 ID fan outlet damper linkage broke. Derated the unit to isolate the ID fan until scaffolding could be built and repairs made to the damper linkage.		None	Repaired linkage to the outlet damper.
62	SHERCO_G1	Forced	Load limited to 470mws net due to low throttle pressure and CV position.	10/15/2024	10/31/2024	16	High Pressure Relief Valve	During normal operation, boiler relief valve lifted prematurely. Lowered throttle pressure to reset the relief valve until the unit could be removed from service to replace the valve.		Similar occurrence on 8/7/24	Replaced incorrect parts installed from previous repair.
63	SHERCO_G1	Forced	Require unit offline to fix a steam leak from the DA tank, replace a failed Main Steam relief valve that is lifting early and a steam seal leak into the condenser.	11/1/2024	11/22/2024	21	Deaerator Tank	During DA restoration, noted further steam leaking lagging from an unknown location. Required unit offline to investigate and repair as needed.		Similar occurrence on11/1/24 and 12/1/24.	Removed lagging and performed further investigation. No additional leaks were found and DA was returned to service.
64	SHERCO_G1	Forced	Unit 1 Derated to 610MWn due to 13 BCP OOS and unavailable.	11/22/2024	11/27/2024	5	Deaerator Tank	Steam leak noted from downcomer into the deaerator tank. Required unit offline to investigate and repair.		Similar occurrence on 11/25/24 and 12/1/24.	Found welds that required excavation and rewelding. Completed welding and returned DA to service.
65	SHERCO_G1	Forced	During restoration of the DA isolation it was noted that there was a leak in an area of the DA that was not repaired during the previous outage.	11/25/2024	11/30/2024	6	13 Boiler Circulating Water Pump	High vibrations noted on 13 BCP. Derated unit and removed boiler circ pump from service.		None	Replace 13 BCP during April 2025 outage.
66	SHERCO_G1	Forced	There was a leak in an area of the DA that was not repaired during the previous outage. Require unit offline to enter DA and repair.	12/1/2024	12/10/2024	10	Boiler Tubing	Tube leak in reheat section of the boiler.		Similar occurrence on 9/23/24 on Unit 3 and 9/29/24 and 10/1/24.	Derated unit to allow unit to stay online and minimize tube leak damage until unit could be removed from service to enter the boiler and repair the leak.
67	SHERCO_G1	Forced	Unit 1 Derated to 555MWn due to 5 coal mills available. 13 Coal mill OOS and 17 coal mill unable to keep running.	12/12/2024	12/18/2024	6	Deaerator Tank	During DA restoration, noted further steam leaking lagging from an unknown location. Required unit offline to investigate and repair as needed.		Similar occurrence on11/1/24 and 11/25/24.	Removed lagging and performed further investigation. No additional leaks were found and DA was returned to service.
68	SHERCO_G1	Forced	Sherco Unit 1 derated to 400 mws net because of 4 coal mill operation. 13 and 17 coal mill OOS for internal repairs. 12 coal mill OOS for coal leak repairs.	12/18/2024	12/23/2024	5	Coal Mills	13 and 17 Coal Mills removed from service due to internal damage.		Derates due to having more than one coal mill out of service preventing the unit from making full load capability. Similar occurrence on 4/15/24, 5/1/24, 8/1/24, and 12/13/24 for Unit 3. Similar Occurrence on 9/19/24, and 12/18/24 on Unit 1.	Repaired internal damage on 17 coal mill r to restore minimum number of mills for full load operation.
69	SHERCO_G1	Forced	Unit 1 Derated to 555MWn due to tube leak	12/23/2024	12/31/2024	8	Coal Mills	13 and 17 Coal Mills removed from service due to internal damage. 12 coal mill's coal transport line developed a coal leak.		Derates due to having more than one coal mill out of service preventing the unit from making full load capability. Similar occurrence on 4/15/24, 5/1/24, 8/1/24, and 12/13/24 for Unit 3. Similar Occurrence on 9/19/24, and 12/12/24 on Unit 1.	Repaired internal damage on 17 coal mill and fixed 12 coal mill coal leak r to restore minimum number of mills for full load operation.

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	Unit	Outage Category	Primary Reason for Planned Outage	Outage Dates Start	Outage Dates End	Duration (Days)	Description of Actions Taken During Outage	Change in Energy Costs ($s)
1	Blk_Dog_G52	Scheduled	Planned Outage-Summer prep\extension-Issues with U5 Turning Gear Motor	5/5/2024	5/31/2024	27	U5 Borescope inspection, U2 HP Bypass valve, Duct Burner automation piping, 51 LO pump replacement, U2 WHM replacement, U2 TD piping penetration replacement, HP attemperator valve replacement, HRSG cleaning & repairs, condenser cleaning, and BOP repairs.	
2	Blk_Dog_G52	Scheduled	Planned Outage extension-Issues with U5 Turning Gear Motor	6/1/2024	6/5/2024	4	Outage extension due to U5 turning gear issues.	
3	Blk_Dog_G52	Scheduled	Planned outage-winter prep	9/29/2024	9/30/2024	2	Unit 5/2 Winter Prep outage to clean HRSG and condenser and to complete U5 borescope inspection.	
4	Blk_Dog_G52	Scheduled	Planned outage-winter prep	10/1/2024	10/5/2024	5	Unit 5/2 Winter Prep outage to clean HRSG and condenser and to complete U5 borescope inspection.	
5	CC Highbridge1	Scheduled	PO (Planned Outage) Units 7, 8 & 9 (HBC 1&2) Offline for Summer Prep Outage	4/20/2024	4/30/2024	11	Borescope U7/U8 CT's, Clean ST Condenser, BOP repairs	
6	CC Highbridge1	Scheduled	PO (Planned Outage) Units 7, 8 & 9 (HBC 1&2) Offline for Summer Prep Outage	5/1/2024	5/3/2024	3	Borescope U7/U8 CT's, Clean ST Condenser, BOP repairs	
7	CC Highbridge1	Scheduled	05/01/2024 07:55 U1 outage extension to replace an inspection discovered CT combustion transition piece.	5/3/2024	5/10/2024	7	Extended outage to replace cracked transition piece in U7 CT discovered during borescope inspection.	
8	CC Highbridge1	Scheduled	High Bridge Units 7,8 & 9 (HBC 1 & 2) Offline for Fall Overhaul.	9/15/2024	9/30/2024	16	U7 Hot Gas Path (CT Upgraded to M501F4) , Plant Wide Controls Upgrade	
9	CC Highbridge1	Scheduled	Offline for Fall Overhaul.	10/1/2024	10/31/2024	31	U7 Hot Gas Path (CT Upgraded to M501F4) , Plant Wide Controls Upgrade	
10	CC Highbridge1	Scheduled	Offline for Fall Overhaul and Planned outage extension until u7 startup testing.	11/1/2024	11/13/2024	12	U7 Hot Gas Path (CT Upgraded to M501F4) , Plant Wide Controls Upgrade	
11	CC Highbridge2	Scheduled	PO (Planned Outage) Units 7, 8 & 9 (HBC 1&2) Offline for Summer Prep Outage	4/20/2024	4/30/2024	11	Borescope U7/U8 CT's, Clean ST Condenser, BOP repairs	
12	CC Highbridge2	Scheduled	PO (Planned Outage) Units 7, 8 & 9 (HBC 1&2) Offline for Summer Prep Outage	5/1/2024	5/3/2024	2	Borescope U7/U8 CT's, Clean ST Condenser, BOP repairs	
13	CC Highbridge2	Scheduled	High Bridge Units 7,8 & 9 (HBC 1 & 2) Offline for Fall Overhaul.	9/15/2024	9/30/2024	16	Plant Wide Controls Upgrade	
14	CC Highbridge2	Scheduled	Offline for Fall Overhaul.	10/1/2024	10/31/2024	31	Plant Wide Controls Upgrade	
15	CC Highbridge2	Scheduled	Offline for Fall Overhaul andU8 Planned Outage Extension.	11/1/2024	11/15/2024	14	Plant Wide Controls Upgrade	
16	CCRiverside1	Scheduled	Borescope, condenser clean, and summer prep outage	3/31/2024	3/31/2024	1	Borescope U9 CT, Clean ST Condenser, BOP repairs (1st quarter portion of Summer prep outage)	
17	CCRiverside1	Scheduled	Borescope, condenser clean, and summer prep outage	4/1/2024	4/21/2024	21	Borescope U9 CT, Clean ST Condenser, BOP repairs (2nd quarter portion of Summer prep outage)	
18	CCRiverside1	Scheduled	Outage extension due to U7 circ water debris filter repairs	4/21/2024	4/24/2024	3	Completion of debris filter repairs required 3 additional days.	
19	CCRiverside1	Scheduled	Winter Prep Outage and condenser cleaning/Extension/Testing following outage	9/7/2024	9/21/2024	15	Clean ST Condenser, BOP repairs, vendor material issues with fuel gas isolation valve replacement project resulted in one day extension to the outage duration.	
20	CCRiverside2	Scheduled	Borescope, condenser clean, and summer prep outage	3/31/2024	3/31/2024	1	Borescope U10 CT, Clean ST Condenser, BOP repairs (1st quarter portion of Summer prep outage)	
21	CCRiverside2	Scheduled	Borescope, condenser clean, and summer prep outage	4/1/2024	4/21/2024	21	Borescope U10 CT, Clean ST Condenser, BOP repairs (2nd quarter portion of Summer prep outage)	
22	CCRiverside2	Scheduled	Outage extension due to U7 circ water debris filter repair	4/21/2024	4/24/2024	3	Completion of debris filter repairs required 3 additional days.	
23	CCRiverside2	Scheduled	Winter Prep Outage and condenser cleaning/Extension/Testing following outage	9/7/2024	9/21/2024	15	Clean ST Condenser, BOP repairs, vendor material issues with fuel gas isolation valve replacement project resulted in one day extension to the outage duration.	
24	King_G1	Scheduled	PO (Planned Outage)	5/10/2024	5/31/2024	21	MATS Rule required Environmental inspection and electrical protection device testing.	
25	King_G1	Scheduled	Planned Outage Extension - 05 Isophase test results were poor and needs to be cleaned	6/1/2024	6/20/2024	20	Cleaning of isophase (isolated-phase bus (IPB)	
26	Monticello_1	Scheduled	Derate for Turbine Valve Testing	9/12/2024	9/13/2024	2	Required downpower for semi-annual testing of turbine valves.	

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	Unit	Outage Category	Primary Reason for Planned Outage	Outage Dates Start	End	Duration (Days)	Description of Actions Taken During Outage	Change in Energy Costs ($s)
27	Monticello_1	Scheduled	Derate for condenser waterbox cleaning with rod sequence exchange	12/9/2024	12/13/2024	3	Derate for condenser cleaning to remove river-borne debris and control rod sequence exchange for core power management.	
28	PR_ISLD_1	Scheduled	DC Cable Replacement Outage	1/1/2024	1/27/2024	27	Planned cable replacement outage that started 11/14/2023 following a reactor trip after damage to DC control cable on 10/19/2023. Refer to Docket No. E002/AA-22-179 for more information.	
29	PR_ISLD_1	Scheduled	Derate for Circ Water Box Air Injector Plugging	5/15/2024	5/31/2024	16	Derate for condenser cleaning to remove river-borne debris.	
30	PR_ISLD_1	Scheduled	(Same as above) Derate for Circ Water Box Air Injector Plugging	6/1/2024	6/14/2024	13	Derate for condenser cleaning to remove river-borne debris.	
31	PR_ISLD_1	Scheduled	Coastdown to planned refueling outage and due to Circulating Water Pump low seal water pressure	9/1/2024	9/20/2024	19	Coastdown to planned refueling outage; this also protected circulating water pumps due to indicated low seal water pressure.	
32	PR_ISLD_1	Scheduled	1R34 Planned Refuel Outage	9/20/2024	9/30/2024	11	Planned refueling outage activities, reactor vessel baffle former bolt and clevis bolt replacement project, 10-year in-service testing (various pumps and valves)	
33	PR_ISLD_1	Scheduled	(Same as above) 1R34 Planned Refuel Outage	10/1/2024	10/31/2024	31	Planned refueling outage activities, reactor vessel baffle former bolt and clevis bolt replacement project, 10-year in-service testing (various pumps and valves).	
34	PR_ISLD_1	Scheduled	(Same as above) 1R34 Planned Refuel Outage	11/1/2024	11/30/2024	30	Planned refueling outage activities, reactor vessel baffle former bolt and clevis bolt replacement project, 10-year in-service testing (various pumps and valves) Discovery: reactor vessel baffle former bolt and clevis bolt replacement project delays, containment crane weld repair	
35	PR_ISLD_1	Scheduled	(Same as above) 1R34 Planned Refuel Outage	12/1/2024	12/31/2024	31	Outage startup activities Discovery: reactor coolant pump seal replacements, reactor coolant pump seal injection filter replacements	
36	PR_ISLD_2	Scheduled	2R33 Planned Refuel Outage	1/1/2024	1/31/2024	31	Refueling outage, DC cable replacement test activities	
37	PR_ISLD_2	Scheduled	(Same as above) 2R33 Planned Refuel Outage	2/1/2024	2/29/2024	29	DC cable replacement test activities, startup activities Discovery: reactor vessel head o-ring replacement, nuclear intermediate range detector replacement	
38	PR_ISLD_2	Scheduled	(Same as above) 2R33 Planned Refuel Outage	3/1/2024	3/1/2024	1	Startup activities	
39	PR_ISLD_2	Scheduled	Power Ascension Hold 49% to 77%, did not use Condensate Polishing for secondary clean, used natural recirc which took longer than normal to clear chemistry holds and ramp up.	3/9/2024	3/15/2024	6	Power ascension hold for chemistry stabilization (a normal part of start up activities).	
40	PR_ISLD_2	Scheduled	Derate for Condenser Water Box issues, Air Removal System	5/1/2024	5/15/2024	14	Repaired a flanged valve that was preventing ability to increase water box level in the outer pass and therefore, the use of the condenser tube cleaning system which decreases plant efficiency.	
41	SHERC3	Scheduled	Outage for summer prep and place holder for unit 3 chemical clean.	5/11/2024	5/21/2024	10	Summer prep including re-packing several valves that had steam leaks, replacing 31 Boiler Feed Pump recirc control valve, repair seals on 36 and 38 SDA outlet dampers, repairing failed desuper heat spray valve SMS CV 3026. Chem clean was moved to 2026.	
42	SHERC3	Scheduled	U3 Maintenance Outage required for a Boiler water-wall tube leak repair. Unit off AGC.	9/2/2024	9/7/2024	5	Repair boiler tube leak. Replace 33 BFPT stop valve. Repair generator output breaker disconnect.	
43	SHERC3	Scheduled	Require unit offline to tie-in steam supply to LPI from Unit 3.	10/12/2024	10/31/2024	20	Run steam lines from Unit 3 to Liberty Paper Inc. to allow for unit 3 to supply steam to LPI. Clean 3 main condenser tubes. Cleaned circ water basin. Clean Aux Cooling heat exchangers. Re-pack various steam valves that were leaking.	

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	Unit	Outage Category	Primary Reason for Planned Outage	Outage Dates Start	End	Duration (Days)	Description of Actions Taken During Outage	Change in Energy Costs ($s)
44	SHERC3	Scheduled	Require unit offline to tie-in steam supply to LPI from Unit 3.	11/1/2024	11/3/2024	3	Run steam lines from Unit 3 to Liberty Paper Inc. to allow for unit 3 to supply steam to LPI. Clean 3 main condenser tubes. Cleaned circ water basin. Clean Aux Cooling heat exchangers. Re-pack various steam valves that were leaking.	
45	SHERCO_G1	Scheduled	Unit 1 planned spring outage.	2/24/2024	4/22/2024	58	Boiler cleaning and inspection, Burner Tip Replacement, MATS inspections and repairs, breaching blank project to isolate input from unit 2, Circulating Water basin cleaning and piping inspection, main condenser cleaning, critical electrical PMs and inspections, scrubber module major cleaning, Isophase bus inspection and repair, bottom ash hopper cleaning and repair, bottom ash grinder replacements, 12 boiler feed pump rotating assembly replacement, 2 coal mill overhauls, blank install for #3 transfer hopper.	
46	SHERCO_G1	Scheduled	Tube Leak Repair	10/7/2024	10/11/2024	4	Maintenance outage to repair identified superheat and water wall tube leak.	

PROTECTED DATA ENDS]

Northern States Power Company
Unit Outage Information
UNPLANNED OUTAGES

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Unit	Type of Plant	Outage Category	Date	Duration (Days)	Actual ($) [PROTECTED DATA BEGINS Total Outage MWh	Actual ($) Average Replacement Cost ($)	Actual ($) Unit Incremental Cost ($)	Actual ($) Change in Energy Cost Due to Outages ($)
Black Dog Total				**0**		**0**		
High Bridge 1x1 Total				**0**		**0**		
High Bridge 2x1 Total				**0**		**0**		
CCRiverside1	CC	Forced	1/4/2024 - 1/8/2024	4		602,352		
CCRiverside1	CC	Forced	4/24/2024 - 4/27/2024	3		389,368		
CCRiverside1	CC	Forced	10/30/2024 - 10/31/2024	2		300,404		
Riverside 1x1 Total				**9**		**1,292,124**		
CCRiverside2	CC	Forced	4/24/2024 - 4/29/2024	5		555,823		
CCRiverside2	CC	Forced	5/12/2024 - 5/14/2024	3		336,505		
CCRiverside2	CC	Forced	10/30/2024 - 10/31/2024	2		300,449		
CCRiverside2	CC	Forced	11/19/2024 - 11/20/2024	1		16,982		
CCRiverside2	CC	Forced	11/20/2024 - 11/22/2024	1		209,281		
Riverside 2x1 Total				**12**		**1,419,039**		
King_G1	Steam	Forced	7/10/2024 - 7/12/2024	2		32,734		
King_G1	Steam	Forced	7/16/2024 - 7/20/2024	4		1,057,561		
King_G1	Steam	Forced	7/23/2024 - 7/31/2024	8		3,240,690		
King_G1	Steam	Forced	8/1/2024 - 8/10/2024	10		2,861,662		
King_G1	Steam	Forced	12/11/2024 - 12/15/2024	4		313,085		
Allen S King Total				**27**		**7,505,733**		
SHERCO_G1	Steam	Forced	1/1/2024 - 1/12/2024	11		1,058,250		
SHERCO_G1	Steam	Forced	1/13/2024 - 1/22/2024	9		1,852,941		
SHERCO_G1	Steam	Forced	1/22/2024 # 1/31/2024	10		1,103,645		
SHERCO_G1	Steam	Forced	2/1/2024 - 2/20/2024	19		289277		
SHERCO_G1	Steam	Forced	2/20/2024 - 2/24/2024	4		133,215		
SHERCO_G1	Steam	Forced	5/1/2024 - 5/31/2024	31		1,886,687		
SHERCO_G1	Steam	Forced	6/1/2024 - 6/19/2024	18		294,621		
SHERCO_G1	Steam	Forced	6/20/2024 - 6/28/2024	8		253,374		
SHERCO_G1	Steam	Forced	6/28/2024 - 6/30/2024	3		116,864		
SHERCO_G1	Steam	Forced	7/1/2024 - 7/11/2024	11		865,863		
SHERCO_G1	Steam	Forced	7/11/2024 - 7/17/2024	5		385,378		
SHERCO_G1	Steam	Forced	7/17/2024 - 7/24/2024	7		58,095		
SHERCO_G1	Steam	Forced	7/24/2024 - 7/26/2024	2		35,947		
SHERCO_G1	Steam	Forced	8/1/2024 - 8/7/2024	6		414,633		
SHERCO_G1	Steam	Forced	8/10/2024 - 8/24/2024	14		324,932		
SHERCO_G1	Steam	Forced	8/28/2024 - 8/31/2024	4		402,499		
SHERCO_G1	Steam	Forced	8/7/2024 - 8/10/2024	3		589,815		
SHERCO_G1	Steam	Forced	8/24/2024 - 8/28/2024	4		2,722,170		
SHERCO_G1	Steam	Forced	9/1/2024 - 9/4/2024	3		40,214		
SHERCO_G1	Steam	Forced	9/4/2024 - 9/6/2024	3		314,704		
SHERCO_G1	Steam	Forced	9/15/2024 - 9/18/2024	4		247,511		
SHERCO_G1	Steam	Forced	9/19/2024 - 9/23/2024	4		293,611		
SHERCO_G1	Steam	Forced	9/29/2024 - 9/30/2024	2		528,718		
SHERCO_G1	Steam	Forced	10/1/2024 - 10/7/2024	6		1,099,738		
SHERCO_G1	Steam	Forced	10/11/2024 - 10/15/2024	4		1,962,668		
SHERCO_G1	Steam	Forced	10/15/2024 - 10/31/2024	16		693,083		
SHERCO_G1	Steam	Forced	11/22/2024 - 11/27/2024	5		2,015,033		
SHERCO_G1	Steam	Forced	11/25/2024 - 11/30/2024	6		1,740,277		
SHERCO_G1	Steam	Forced	11/1/2024 - 11/22/2024	21		6,797,181		
SHERCO_G1	Steam	Forced	12/12/2024 - 12/18/2024	6		759,380		
SHERCO_G1	Steam	Forced	12/18/2024 - 12/23/2024	5		958,041		
SHERCO_G1	Steam	Forced	12/23/2024 - 12/31/2024	8		636,122		
SHERCO_G1	Steam	Forced	12/1/2024 - 12/10/2024	10		4,712,521		
Sherburne 1 Total				**273**		**35,587,008**		

Unit	As Forecasted ($) Total Outage MWh	As Forecasted ($) Average Replacement Cost ($)	As Forecasted ($) Unit Incremental Cost ($)	As Forecasted ($) Change in Energy Cost Due to Outages ($)	Actual ($/MWh) Average Replacement Cost $/MWh	Actual ($/MWh) Unit Incremental Cost $/MWh	Actual ($/MWh) Change in Energy Cost Due to Outages ($)	As Forecasted ($/MWh) Average Replacement Cost $/MWh	As Forecasted ($/MWh) Unit Incremental Cost $/MWh	As Forecasted ($/MWh) Change in Energy Cost Due to Outages ($)
Black Dog Total		3,661,440			0.00			39.01		
High Bridge 1x1 Total		1,145,218			0.00			33.50		
High Bridge 2x1 Total		1,233,395			0.00			40.86		
Riverside 1x1 Total		5,182,513			36.01			35.84		
Riverside 2x1 Total		4,489,504			28.80			34.75		
Allen S King Total		10,860,374			31.76			48.51		
Sherburne 1 Total		25,528,341			32.44			41.24		

Northern States Power Company
Unit Outage Information
UNPLANNED OUTAGES

Protected Data is Shaded

[PROTECTED DATA BEGINS

Unit	Type of Plant	Outage Category	Date	Duration (Days)	Actual ($) Total Outage MWh	Actual ($) Average Replacement Cost ($)	Actual ($) Unit Incremental Cost ($)	Actual ($) Change in Energy Cost Due to Outages ($)	As Forecasted ($) Total Outage MWh	As Forecasted ($) Average Replacement Cost ($)	As Forecasted ($) Unit Incremental Cost ($)	As Forecasted ($) Change in Energy Cost Due to Outages ($)	Actual ($/MWh) Average Replacement Cost $/MWh	Actual ($/MWh) Unit Incremental Cost $/MWh	Actual ($/MWh) Change in Energy Cost Due to Outages ($)	As Forecasted ($/MWh) Average Replacement Cost $/MWh	As Forecasted ($/MWh) Unit Incremental Cost $/MWh	As Forecasted ($/MWh) Change in Energy Cost Due to Outages ($)
SHERC3	Steam	Forced	1/3/2024 - 1/5/2024	2		169,120												
SHERC3	Steam	Forced	4/15/2024 - 4/19/2024	4		68,501												
SHERC3	Steam	Forced	5/1/2024 - 5/2/2024	2		193,962												
SHERC3	Steam	Forced	5/2/2024 - 5/6/2024	4		361,664												
SHERC3	Steam	Forced	7/5/2024 - 7/8/2024	2		561,253												
SHERC3	Steam	Forced	7/8/2024 - 7/11/2024	3		1,368,431												
SHERC3	Steam	Forced	8/1/2024 - 8/4/2024	3		377,246												
SHERC3	Steam	Forced	8/14/2024 - 8/27/2024	13		977,133												
SHERC3	Steam	Forced	8/27/2024 - 8/31/2024	4		510,637												
SHERC3	Steam	Forced	9/1/2024 - 9/2/2024	1		47,068												
SHERC3	Steam	Forced	9/7/2024 - 9/23/2024	16		2,056,835												
SHERC3	Steam	Forced	9/23/2024 - 9/30/2024	8		2,918,455												
SHERC3	Steam	Forced	10/1/2024 - 10/11/2024	11		1,057,665												
SHERC3	Steam	Forced	12/13/2024 - 12/17/2024	4		379,932												
Sherburne 3 Total				**78**		**11,047,901**				11,427,396			32.96			42.59		
Monticello_1	Nuclear	Forced	2/28/2024 - 2/29/2024	2		610,221												
Monticello_1	Nuclear	Forced	3/1/2024 - 3/3/2024	2		561,885												
Monticello_1	Nuclear	Forced	3/27/2024 - 3/31/2024	5		1,427,349												
Monticello Total				**9**		**2,599,455**				3,227,978			18.50			28.55		
PR_ISLD_1	Nuclear	Forced	2/9/2024 - 2/12/2024	4		959,967												
PR_ISLD_1	Nuclear	Forced	6/14/2024 - 6/19/2024	5		870,305												
Prairie Island 1 Total				**9**		**1,830,271**				2,216,722			19.73			30.99		
PR_ISLD_2	Nuclear	Forced	3/16/2024 - 3/17/2024	1		21,472												
PR_ISLD_2	Nuclear	Forced	3/3/2024 - 3/8/2024	5		1,411,816												
PR_ISLD_2	Nuclear	Forced	10/29/2024 - 10/31/2024	3		906,830												
PR_ISLD_2	Nuclear	Forced	11/1/2024 - 11/10/2024	9		3,017,034												
Prairie Island 2 Total				**17**		**5,357,152**				-			23.87			-		
Total				**434**	**2,211,581**	**66,638,684**	**44,093,069**	**22,545,615**	**1,727,837**	**68,972,881**	**44,602,501**	**24,370,378**	**30.13**	**19.94**	**10.19**	39.92	25.81	14.10

PROTECTED DATA ENDS]

Northern States Power Company
Unit Outage Information
PLANNED OUTAGES

Protected Data is Shaded

							Actual ($)				As Forecasted ($)				Actual ($/MWh)			As Forecasted ($/MWh)		
							[PROTECTED DATA BEGINS													
Unit	Type of Plant	Outage Category	Date			Duration (Days)	Total Outage MWh	Average Replacement Cost ($)	Unit Incremental Cost ($)	Change in Energy Cost Due to Outages ($)	Total Outage MWh	Average Replacement Cost ($)	Unit Incremental Cost ($)	Change in Energy Cost Due to Outages ($)	Average Replacement Cost $/MWh	Unit Incremental Cost $/MWh	Change in Energy Cost Due to Outages ($)	Average Replacement Cost $/MWh	Unit Incremental Cost $/MWh	Change in Energy Cost Due to Outages ($)
Blk_Dog_G52	Steam	Scheduled	5/5/2024	-	5/31/2024	27		2,950,534												
Blk_Dog_G52	Steam	Scheduled	6/1/2024	-	6/5/2024	4		439,956												
Blk_Dog_G52	Steam	Scheduled	9/29/2024	-	9/30/2024	2		236,303												
Blk_Dog_G52	Steam	Scheduled	10/1/2024	-	10/5/2024	5		605,006												
Black Dog 25 Total						**38**		**4,231,798**				1,916,477			25.21			29.64		
CC Highbridge1	CC	Scheduled	04/20/2024	-	04/30/2024	11		1,025,389												
CC Highbridge1	CC	Scheduled	05/01/2024	-	05/03/2024	3		506,610												
CC Highbridge1	CC	Scheduled	05/03/2024	-	05/10/2024	7		886,759												
CC Highbridge1	CC	Scheduled	09/15/2024	-	09/30/2024	16		3,021,669												
CC Highbridge1	CC	Scheduled	10/01/2024	-	10/31/2024	31		4,600,967												
CC Highbridge1	CC	Scheduled	11/01/2024	-	11/13/2024	12		1,582,507												
Highbridge 1x1 Total						**80**		**11,623,901**				8,628,611			27.87			32.28		
CC Highbridge2	CC	Scheduled	4/20/2024	-	4/30/2024	11		1,025,079												
CC Highbridge2	CC	Scheduled	5/1/2024	-	5/3/2024	2		501,150												
CC Highbridge2	CC	Scheduled	9/15/2024	-	9/30/2024	16		3,019,851												
CC Highbridge2	CC	Scheduled	10/1/2024	-	10/31/2024	31		4,600,956												
CC Highbridge2	CC	Scheduled	11/1/2024	-	11/15/2024	14		1,846,121												
Highbridge 2x1 Total						**75**		**10,993,156**				8,603,222			28.39			32.29		
CCRiverside1	CC	Scheduled	03/31/2024	-	03/31/2024	1		158,358												
CCRiverside1	CC	Scheduled	04/21/2024	-	04/24/2024	3		516,896												
CCRiverside1	CC	Scheduled	04/01/2024	-	04/21/2024	21		2,189,021												
CCRiverside1	CC	Scheduled	09/07/2024	-	09/21/2024	15		2,317,564												
Riverside 1x1 Total						**39**		**5,181,838**				1,751,721			27.45			30.71		
CCRiverside2	CC	Scheduled	3/31/2024	-	3/31/2024	1		158,395												
CCRiverside2	CC	Scheduled	4/21/2024	-	4/24/2024	3		503,910												
CCRiverside2	CC	Scheduled	04/01/2024	-	04/21/2024	21		2,185,828												
CCRiverside2	CC	Scheduled	09/07/2024	-	09/21/2024	15		2,313,118												
Riverside 2x1 Total						**39**		**5,161,251**				1,722,923			27.60			30.88		
King_G1	Steam	Scheduled	5/10/2024	-	5/31/2024	21		5,869,254												
King_G1	Steam	Scheduled	6/1/2024	-	6/20/2024	20		4,466,630												
Allen S King Total						**41**		**10,335,884**							24.09			-		
SHERCO_G1	Steam	Scheduled	2/24/2024	-	2/29/2024	6		1,420,051												
SHERCO_G1	Steam	Scheduled	3/1/2024	-	3/31/2024	31		7,204,093												
SHERCO_G1	Steam	Scheduled	4/1/2024	-	4/22/2024	21		5,722,678												
SHERCO_G1	Steam	Scheduled	10/7/2024	-	10/11/2024	4		1,962,668												
Sherburne 1 Total						**63**		**16,309,490**				12,573,408			23.72			-		
SHERC3	Steam	Scheduled	5/11/2024	-	5/21/2024	10		3,022,701												
SHERC3	Steam	Scheduled	9/2/2024	-	9/7/2024	5		1,020,117												
SHERC3	Steam	Scheduled	10/12/2024	-	10/31/2024	20		4,863,016												
SHERC3	Steam	Scheduled	11/1/2024	-	11/3/2024	3		734,558												
Sherburne 3 Total						**38**		**9,640,392**				584,308			26.81			29.74		
Monticello_1	Nuclear	Scheduled	9/12/2024	-	9/13/2024	2		16,308												
Monticello_1	Nuclear	Scheduled	12/9/2024	-	12/13/2024	3		611,944												
Monticello Total						**5**		**628,252**							45.00			-		

Northern States Power Company
Unit Outage Information
PLANNED OUTAGES

Protected Data is Shaded

[PROTECTED DATA BEGINS

Unit	Type of Plant	Outage Category	Date	Duration (Days)	Actual ($): Total Outage MWh	Actual ($): Average Replacement Cost ($)	Actual ($): Unit Incremental Cost ($)	Actual ($): Change in Energy Cost Due to Outages ($)	As Forecasted ($): Total Outage MWh	As Forecasted ($): Average Replacement Cost ($)	As Forecasted ($): Unit Incremental Cost ($)	As Forecasted ($): Change in Energy Cost Due to Outages ($)	Actual ($/MWh): Average Replacement Cost $/MWh	Actual ($/MWh): Unit Incremental Cost $/MWh	Actual ($/MWh): Change in Energy Cost Due to Outages ($)	As Forecasted ($/MWh): Average Replacement Cost $/MWh	As Forecasted ($/MWh): Unit Incremental Cost $/MWh	As Forecasted ($/MWh): Change in Energy Cost Due to Outages ($)
PR_ISLD_1	Nuclear	Scheduled	1/1/2024 - 1/27/2024	27		17,751,676												
PR_ISLD_1	Nuclear	Scheduled	5/15/2024 - 5/31/2024	16		127,333												
PR_ISLD_1	Nuclear	Scheduled	6/1/2024 - 6/14/2024	13		101,724												
PR_ISLD_1	Nuclear	Scheduled	9/1/2024 - 9/20/2024	19		300,938												
PR_ISLD_1	Nuclear	Scheduled	9/20/2024 - 9/30/2024	11		3,842,361												
PR_ISLD_1	Nuclear	Scheduled	10/1/2024 - 10/31/2024	31		9,247,762												
PR_ISLD_1	Nuclear	Scheduled	11/1/2024 - 11/30/2024	30		9,602,820												
PR_ISLD_1	Nuclear	Scheduled	12/1/2024 - 12/31/2024	31		13,626,643												
Prairie Island 1 Total				**179**		**54,601,256**				22,988,926			31.09			-		
PR_ISLD_2	Nuclear	Scheduled	01/01/2024 - 01/31/2024	31		18,079,803												
PR_ISLD_2	Nuclear	Scheduled	02/01/2024 - 02/29/2024	29		8,319,422												
PR_ISLD_2	Nuclear	Scheduled	03/01/2024 - 03/01/2024	1		175,543												
PR_ISLD_2	Nuclear	Scheduled	03/09/2024 - 03/15/2024	6		609,833												
PR_ISLD_2	Nuclear	Scheduled	05/01/2024 - 05/15/2024	14		1,247,454												
Prairie Island 2 Total				**81**		**28,432,056**							31.51			-		
Total				**677**	**5,497,009**	**157,139,275**	**81,471,553**	**75,667,722**	**1,907,216**	**58,769,596**	**33,993,431**	**24,776,165**	**28.59**	**14.82**	**13.77**	**30.81**	**17.82**	**12.99**

PROTECTED DATA ENDS]

Northern States Power Company
Unit Outage Information
UNPLANNED OUTAGES

Protected Data is Shaded

			[PROTECTED DATA BEGINS				As Forecasted ($)				Actual ($/MWh)			As Forecasted ($/MWh)		
Year	Type of Plant	Outage Category	Total Outage MWh	Average Replacement Cost ($)	Unit Incremental Cost ($)	Change in Energy Cost Due to Outages ($)	Total Outage MWh	Average Replacement Cost ($)	Unit Incremental Cost ($)	Change in Energy Cost Due to Outages ($)	Average Replacement Cost $/MWh	Unit Incremental Cost $/MWh	Change in Energy Cost Due to Outages ($)	Average Replacement Cost $/MWh	Unit Incremental Cost $/MWh	Change in Energy Cost Due to Outages ($)
2021	Steam	Forced		-				2,469,988						25.89		
2022	Steam	Forced		540,106				770,625			60.63			32.37		
2023	Steam	Forced		3,154,675				4,297,022			32.00			56.44		
2024	Steam	Forced		3,154,675				3,661,440			0.00			39.01		
Black Dog 25 Total				**6,849,456**				11,199,075			33.24			38.72		
2021	CC	Forced		297,523				377,235			26.38			26.68		
2022	CC	Forced		102,916				65,722			63.92			28.96		
2023	CC	Forced		489,567				2,630,971			43.44			52.56		
2024	CC	Forced		0				1,145,218			0.00			33.50		
Highbridge 1x1 Total				**890,005**				4,219,145			36.84			41.92		
2021	CC	Forced		104,373				292,386			26.16			24.16		
2022	CC	Forced		650,878				176,358			83.65			32.16		
2023	CC	Forced		1,005,088				6,611,055			32.18			48.94		
2024	CC	Forced		0				1,233,395			0			40.86		
Highbridge 2x1 Total				**1,760,339**				8,313,194			40.93			45.46		
2021	CC	Forced		753,915				699,703			36.41			21.60		
2022	CC	Forced		-				813,849			-			29.79		
2023	CC	Forced		698,384				7,186,476			26.70			48.29		
2024	CC	Forced		1,452,299				5,182,513			36.01			35.84		
Riverside 1x1 Total				**2,904,598**				13,882,541			30.99			39.32		
2021	CC	Forced		728,746				754,774			35.78			24.34		
2022	CC	Forced		-				646,840			-			27.36		
2023	CC	Forced		1,005,088				6,611,055			32.18			48.94		
2024	CC	Forced		1,419,039				4,489,504			28.80			34.75		
Riverside 2x1 Total				**3,152,874**				12,502,173			31.26			39.20		
2021	Steam	Forced		-				2,022,062			-			32.10		
2022	Steam	Forced		12,944,671				2,386,625			51.42			41.39		
2023	Steam	Forced		18,869,974				11,896,714			32.58			67.24		
2024	Steam	Forced		7,505,733				10,860,374			31.76			48.51		
Allen S King Total				**39,320,378**				27,165,775			36.84			52.09		
2021	Steam	Forced		5,265,303				6,092,857			39.78			28.56		
2022	Steam	Forced		22,343,504				9,954,204			48.15			29.29		
2023	Steam	Forced		23,816,700				32,877,223			38.07			51.43		
2024	Steam	Forced		35,587,008				25,528,341			32.44			41.24		
Sherburne 1 Total				**87,012,516**				74,452,625			37.52			41.10		
2021	Steam	Forced		4,607,308				1,974,161			39.87			27.38		
2022	Steam	Forced		26,013,995				2,646,622			48.44			30.49		
2023	Steam	Forced		19,294,386				17,710,109			37.49			60.78		
2024	Steam	Forced		11,047,901				11,427,396			32.96			42.59		
Sherburne 3 Total				**60,963,590**				33,758,288			40.58			46.98		
2021	Nuclear	Forced		-				1,906,934			-			21.17		
2022	Nuclear	Forced		1,938,888				434,076			37.53			20.29		
2023	Nuclear	Forced		6,500,281				3,097,556			28.16			43.67		
2024	Nuclear	Forced		2,599,455				3,227,978			32.96			42.59		
Monticello Total				**11,038,624**				8,666,544			26.09			29.33		
2021	Nuclear	Forced		-				3,409,537			-			18.97		
2022	Nuclear	Forced		-				873,301						20.69		
2023	Nuclear	Forced		9,781,870				3,517,909			29.54			44.49		
2024	Nuclear	Forced		1,830,271				2,216,722			19.73			30.99		
Prairie Island 1 Total				**11,612,141**				10,017,468			27.40			26.89		
2021	Nuclear	Forced		-				4,358,735			-			19.30		
2022	Nuclear	Forced		-				2,707,285						23.83		
2023	Nuclear	Forced		5,788,340				168,066			28.40			51.22		
2024	Nuclear	Forced		5,357,152				-			23.87			-		
Prairie Island 2 Total				**11,145,491**				7,234,086			26.02			21.11		

PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Unit Outage Information
PLANNED OUTAGES

Docket No. E002/AA-23-153
True-Up Report
Part C, Attachment 5d

Protected Data is Shaded

							As Forecasted ($)				Actual ($/MWh)			As Forecasted ($/MWh)		
			[PROTECTED DATA BEGINS			Change in				Change in		Unit	Change in		Unit	Change in
			Total	Average	Unit	Energy	Total	Average	Unit	Energy	Average	Incremental	Energy	Average	Incremental	Energy
	Type of	Outage	Outage	Replacement	Incremental	Cost Due to	Outage	Replacement	Incremental	Cost Due to	Replacement	Cost	Cost Due to	Replacement	Cost	Cost Due to
Year	Plant	Category	MWh	Cost ($)	Cost ($)	Outages ($)	MWh	Cost ($)	Cost ($)	Outages ($)	Cost $/MWh	$/MWh	Outages ($)	Cost $/MWh	$/MWh	Outages ($)
2021	Steam	Scheduled		2,177,000				1,141,521			43.09			24.41		
2022	Steam	Scheduled		7,241,303				5,232,523			61.74			27.61		
2023	Steam	Scheduled		2,242,111				3,305,304			40.24			44.46		
2024	Steam	Scheduled		4,231,798				1,916,477			25.21			29.64		
Black Dog 25 Total				**15,892,211**				11,595,825			40.60			30.90		
2021	CC	Scheduled		6,233,490				1,306,811			37.07			22.85		
2022	CC	Scheduled		1,135,209				4,197,367			50.50			27.20		
2023	CC	Scheduled		5,381,818				1,612,226			30.76			47.52		
2024	CC	Scheduled		11,623,901				8,628,611			27.87			32.28		
Highbridge 1x1 Total				**24,374,419**				15,745,016			31.14			30.71		
2021	CC	Scheduled		5,826,831				1,275,777			37.11			22.98		
2022	CC	Scheduled		1,135,362				1,147,506			50.51			27.12		
2023	CC	Scheduled		5,067,858				1,702,904			34.21			45.03		
2024	CC	Scheduled		10,993,156				8,603,222			28.39			32.29		
Highbridge 2x1 Total				**23,023,207**				12,729,410			32.21			31.66		
2021	CC	Scheduled		12,645,801				5,592,239			34.58			22.13		
2022	CC	Scheduled		1,080,317				1,559,665			62.45			27.65		
2023	CC	Scheduled		4,214,237				2,257,911			33.26			43.12		
2024	CC	Scheduled		5,181,838				1,751,721			27.45			30.71		
Riverside 1x1 Total				**23,122,193**				11,161,535			33.10			26.67		
2021	CC	Scheduled		12,812,041				5,326,894			33.73			21.75		
2022	CC	Scheduled		1,080,365				1,466,041			62.46			26.35		
2023	CC	Scheduled		4,061,032				2,254,429			35.05			43.06		
2024	CC	Scheduled		5,161,251				1,722,923			27.60			30.88		
Riverside 2x1 Total				**23,114,689**				10,770,287			33.02			26.35		
2021	Steam	Scheduled		10,573,201				1,512,904			51.49			28.60		
2022	Steam	Scheduled		33,301,406				-			48.60			-		
2023	Steam	Scheduled		5,033,482				-			28.81			-		
2024	Steam	Scheduled		10,335,884				-			24.09			-		
Allen S King Total				**59,243,974**				1,512,904			39.64			28.60		
2021	Steam	Scheduled		19,177,225				5,754,466			25.03			25.22		
2022	Steam	Scheduled		8,853,433				3,202,521			42.00			28.70		
2023	Steam	Scheduled		23,816,700				-			38.07			-		
2024	Steam	Scheduled		16,309,490				12,573,408			23.72			-		
Sherburne 1 Total				**68,156,848**				21,530,395			29.76			31.78		
2021	Steam	Scheduled		1,498,571				-			31.53					
2022	Steam	Scheduled		3,701,087				608,934			39.29			30.49		
2023	Steam	Scheduled		22,758,723				15,923,680			27.74			35.82		
2024	Steam	Scheduled		9,640,392				584,308			26.81			29.74		
Sherburne 3 Total				**37,598,773**				17,116,923			28.45			35.35		
2021	Nuclear	Scheduled		12,164,108				6,818,602			24.23			17.81		
2022	Nuclear	Scheduled		1,546,228				624,972			44.67			20.29		
2023	Nuclear	Scheduled		22,758,723				15,923,680			27.74			35.82		
2024	Nuclear	Scheduled		628,252				-			45.00			-		
Monticello Total				**37,097,311**				23,367,254			27.06			27.22		
2021	Nuclear	Scheduled		-				-			-			-		
2022	Nuclear	Scheduled		12,669,371				5,877,907			33.23			19.42		
2023	Nuclear	Scheduled		5,863,347				-			26.56			-		
2024	Nuclear	Scheduled		54,601,256				22,988,926			31.09			-		
Prairie Island 1 Total				**73,133,975**				28,866,833			31.01			25.29		
2021	Nuclear	Scheduled		20,386,819				5,687,649			49.15			17.81		
2022	Nuclear	Scheduled		38,252				418,594			39.85			23.83		
2023	Nuclear	Scheduled		30,484,568				15,942,370			26.57			40.58		
2024	Nuclear	Scheduled		28,432,056				-			31.51			-		
Prairie Island 2 Total				**79,341,695**				22,048,613			32.18			30.21		

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Northern States Power Company
Expenses Pertaining to Maintenance of Generation Plants

	2024 Test Year	2023 Actuals	2024 Actuals**
Energy Allocation Ratios	**86.7239%**	**86.6425%**	**86.4763%**
Demand Allocation Ratios	**87.1003%**	**87.1503%**	**86.9638%**

			NSP Minnesota Company Totals			Minnesota Jurisdictional Totals *		
FERC Account Description		Allocation Method	2024 Test Year	2023 Actuals	2024 Actuals	2024 Test Year	2023 Actuals	2024 Actuals**
510	Stm Maint Super&Eng	Energy	$ 1,648,128	$ 1,459,264	$ 1,437,329	$ 1,429,321	$ 1,264,342	$ 1,242,949
511	Stm Maint of Structures	Demand	$ 3,193,902	$ 4,931,914	$ 5,132,920	$ 2,781,898	$ 4,298,178	$ 4,463,783
512	Stm Maint of Boiler Plt	Energy	$ 21,443,023	$ 19,448,709	$ 16,892,810	$ 18,596,226	$ 16,850,848	$ 14,608,277
513	Stm Maint of Elec Plant	Energy	$ 4,709,713	$ 6,770,622	$ 5,822,855	$ 4,084,447	$ 5,866,236	$ 5,035,390
514	Stm Maint of Misc Stm Plt	Demand	$ 5,236,403	$ 6,472,630	$ 6,340,754	$ 4,560,923	$ 5,640,916	$ 5,514,161
528	Nuc Maint Super & Eng	Energy	$ 6,897,322	$ 7,891,172	$ 6,485,604	$ 5,981,627	$ 6,837,109	$ 5,608,511
529	Nuc Maint of Structures	Demand	$ -	$ -	$ -	$ -	$ -	$ -
530	Nuc Mtc of React Plt Equip	Energy	$ 34,633,841	$ 26,005,094	$ 22,674,197	$ 30,035,817	$ 22,531,463	$ 19,607,807
531	Nuc Maint of Elect Plant	Energy	$ 12,645,059	$ 13,295,965	$ 14,232,679	$ 10,966,289	$ 11,519,956	$ 12,307,894
532	Nuc Mtc of Misc Nuc Plant	Demand	$ 27,332,951	$ 33,726,695	$ 39,747,996	$ 23,807,082	$ 29,392,916	$ 34,566,374
541	Hydro Mtc Super& Eng	Energy	$ 177,038	$ 78,063	$ 53	$ 153,534	$ 67,636	$ 46
542	Hyd Maint of Structures	Demand	$ 416,273	$ 16,314	$ 18,191	$ 361,008	$ 14,218	$ 15,820
543	Hydro Mtc Resv, Dams	Demand	$ -	$ 362,900	$ 171,879	$ -	$ 316,268	$ 149,473
544	Hyd Maint of Elec Plant	Energy	$ -	$ 158,594	$ 39,913	$ -	$ 137,410	$ 34,515
545	Hyd Mt Misc Hyd Plnt Mjr	Demand	$ 160,577	$ 5,728	$ 136	$ 139,863	$ 4,992	$ 118
551	Oth Maint Super & Eng	Demand	$ 2,049,059	$ 1,368,203	$ 1,473,105	$ 1,784,736	$ 1,192,393	$ 1,281,068
552	Oth Maint of Structures	Demand	$ 4,903,789	$ 7,662,256	$ 7,697,271	$ 4,271,215	$ 6,677,679	$ 6,693,841
553	Oth Mtc of Gen & Ele Plant	Demand	$ 12,894,988	$ 9,714,205	$ 13,941,038	$ 11,231,573	$ 8,465,958	$ 12,123,658
554	Oth Mtc Misc Gen Plt Mjr	Demand	$ 18,397,459	$ 11,047,714	$ 14,395,528	$ 16,024,242	$ 9,628,116	$ 12,518,900
Production Maintenance Expense Totals			**$ 156,739,525**	**$ 150,416,042**	**$ 156,504,260**	**$ 136,209,801**	**$ 130,706,636**	**$ 135,772,586**

*Minnesota jurisdictional totals do not reflect Interchange Agreement billings to NSP-Wisconsin.
**Preliminary Minnesota Demand and Energy Allocation Ratios

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CC Calpine II	5/31/2039	20	Mankato Energy Center II LLC	345	Gas													
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DPC Flambeau	1/31/2037	Life of Project	Dairyland Flambeau	2	Hydro													
Deuel Harvest Wind Energy LLC	9/30/2036	15	Deuel Harvest Wind Energy LLC	300	Wind													
Eau Galle	7/31/2026	35	Eau Galle Renewable Energy Co. Inc.	0.300	Hydro													
Hastings	6/30/2033	45	City of Hastings Hydro	0.450	Hydro													
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HERC	12/30/2024	28	Hennepin Energy Resource Recovery (HERC)	33.7	Digester													
Keller	12/31/2022	MTM	Keller Paving & Landscaping, Inc.	0.19	Solar													
Koda	5/31/2022	10	KODA Energy, LLC	12	Biomass													
Manitoba Hydro	4/30/2025	10	Manitoba Hydro Electric Board	Summer: 375, Winter: 325 (Summer = May thru October)	Hydro													
MidAmerican Energy Company	2/28/2024	0.25	MidAmerican Energy Company	Winter - December, 2023 to February, 2024	Unknown													
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Solar Best Power International PV	5/26/2030	20	St. John's Solar	0.5	Solar													
Solar Best Power International PV II	10/11/2030	15	School Sisters of Notre Dame Solar Park	0.718	Solar													
Solar Dragonfly	9/10/2033	15	Dragonfly Solar, LLC	0.8	Solar													
Solar Marshall	6/8/2042	25.5	Marshall Solar, LLC	62.25	Solar													
Solar North Star	12/20/2041	25.67	North Star Solar PV	100	Solar													
Solar Slayton	1/3/2033	10	Slayton Solar, LLC	1.66	Solar													
St Cloud	10/31/2021	33	The City of St. Cloud	Summer: 8.1, Winter: 6.6 (Summer = May thru October)	Hydro													
StPaul CoGen	3/24/2023	20	St. Paul Cogeneration	25	Biomass													
Western Technical College Angelo Dam	3/31/2024	10	Western Technical College	0.205	Hydro													
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Wind CBED Big Blue	12/14/2032	20	Big Blue Wind Farm, LLC	36	Wind													
Wind CBED Community Wind North	5/27/2031	20	North Wind Turbines LLC North Community Turbines LLC	30	Wind													
Wind CBED Community Wind South	12/25/2032	20	Zephyr Wind, LLC	30	Wind													
Wind CBED Danielson	3/10/2031	20	Danielson Wind Farms, LLC	19.8	Wind													
Wind CBED Ewington	5/27/2028	20	Ewington Energy Systems, LLC	19.95	Wind													
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Wind CBED Jeffers	10/9/2028	20	Jeffers Wind 20 LLC	50	Wind													
Wind CBED Ridgewind	1/12/2031	20	Ridgewind Power Partners LLC	25.3	Wind													
Wind CBED Roseville	8/8/2030	20	Grant County Wind	20	Wind													
Wind CBED Uilk	1/14/2030	20	Uilk Wind Farm, LLC	4.5	Wind													
Wind CBED Valley View	11/29/2031	20	Valley View Transmission, LLC	10	Wind													
Wind CBED Winona	10/26/2031	20	Winona County Wind, LLC	1.5	Wind													
Wind CBED Woodstock	6/23/2030	20	Woodstock Municipal Wind, LLC	0.75	Wind													
Wind Crown Ridge	1/9/2045	25	Crowned Ridge Wind, LLC	200	Wind													
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Wind Dakota Range III	4/30/2033	20	DAKOTA RANGE III, LLC	153.6	Wind													
Wind Eastridge	4/30/2026	20	Bendwind, LLC DeGreeff DP, LLC DeGreeffpa LLC Groen Wind LLC Hillcrest Wind LLC LarswindLLC Sierra Wind LLC TAIR Windfarm LLC	10	Wind													
Wind Fenton	11/12/2032	25	Fenton Power Partners I, LLC	205.5	Wind													
Wind FPL	12/2/2026	20	FPL Energy Mower County, LLC	98.9	Wind													
Wind Garwin McNeilus	Various	20-25	Bangladesh Children's Support LLC, Brandon Wind LLC, BT Windfarm LLC, Burmese Children's Support, LLC, GarMar Foundation I, LLC/ REAP I, Gar Mar Wind I, LLC, GM Windfarm LLC, Henslin Creek LLC, Indian Children's Support, LLC, McNeilus Windfarm LLC, Salvadoran Children's Support , SG (JCKD) Windfarm LLC, Southeast Asian Children's Support, LLC, Triton Wind LLC, Wasioja Wind LLC, Wilhelm Wind LLC	27.5	Wind													
Wind Geronimo Odell	7/28/2036	20	Odell Wind, LLC	200	Wind													
Wind Lakota	4/30/2034	30	Northern Alternative Energy Lakota Ridge LLC	11.25	Wind													
Wind Minn Dakota	12/30/2022	15	MinnDakota Wind LLC	150	Wind													
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Wind North Shaokatan	10/31/2033	30	Autumn Hills LLC, Jack River LLC,Jessica Mills LLC, Julia Hills LLC, Sun River LLC, Tsar Nicholas, LLC	13.53	Wind													
Wind Phase 2	12/13/2028	30	Lake Benton Power Partners LLC (LBI)	105.75	Wind													
Wind Phase 4	12/14/2023	20	Chanarambie Power Partners, LLC	85.5	Wind													
Wind Prairie Rose	12/10/2032	20	Prairie Rose Wind, LLC	200	Wind													
Wind Ruthton	1/22/2031	30	Ruthton Ridge LLC, Florence Hills LLC,Hadley Ridge LLC,Hope Creek LLC, Soliloquy Ridge LLC, Spartan Hills LLC,Twin Lake Hills LL, Winter's Spawn LLC	15.84	Wind													
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Wind Source Garwin McNeilus	4/30/2025	20	Ashland Windfarm LLC, Elsinore Wind LLC, Gar Mar Foundation II / REAP II, Grant Windfarm LLC, Zumbro Windfarm	9.25	Wind													
Wind Source JJN	12/16/2029	25	JJN Windfarm, LLC	1.5	Wind													
Wind Source MinWind	2/1/2025	20	Minwind III -IX, LLC	11.55	Wind													
Wind Source West Ridge	12/27/2028	25	Westridge Windfarm LLC, Tofteland Windfarm LLC, TG Windfarm LLC, CG Windfarm LLC, , Fey Windfarm LLC,	9.5	Wind													
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Wind Tholen	8/27/2025	20	Tholen Transmission Projects	13.2	Wind													
Wind University of Minnesota	10/26/2031		UMORE Park, LLC	2.5	Wind													
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Wind Viking	12/17/2018	15	Buffalo Ridge Wind Farm LLC, Moulton Heights Wind Power Project LLC, Muncie Power Partners LLC, North Ridge Wind Farm LLC, Vandy South Project, Viking Wind Farm LLC, Vindy Power Partners LLC, Wilson-West Windfarm LLC	12	Wind													
Wind Westridge	Various 2028	25	K-Brink Wind Farm, LLC Bisson Windfarm LLC, Boeve Windfarm LLC, Windcurrents Windfarm, LLC	7.6	Wind													
Wind Woodstock	4/30/2034	30	Woodstock Wind Farm, LLC	10.2	Wind													
Louise Solar Project, LLC	6/30/2040	18.5	Louise Solar Project, LLC	50	Solar													
Poet, LLC	Various	MTM	Poet, LLC	0.375	Solar													
Fillmore County Solar Project, LLC	6/30/2040	18.5	Fillmore County Solar Project, LLC	30	Solar													

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Wind Various	Various	30	Agassiz Beach LLC, Metro Wind LLC, Shanes Wind Farm LLC, Carlton College LLC,Kas Brothers Wind LLC, Ed Olsen Wind LLC, Rock Ridge Windfarm LLC, Southridge Windfarm LLC, St.Olaf College, Windvest Windfarm LLC	16.34	Wind															
Wind Velva	1/18/2026	20	Velva Windfarm, LLC	11.88	Wind															
Wind Viking	12/17/2018	15	Buffalo Ridge Wind Farm LLC, Moulton Heights Wind Power Project LLC, Muncie Power Partners LLC, North Ridge Wind Farm LLC, Vandy South Project, Viking Wind Farm LLC, Vindy Power Partners LLC, Wilson-West Windfarm LLC	12	Wind															
Wind Westridge	Various 2028	25	K-Brink Wind Farm, LLC Bisson Windfarm LLC, Boeve Windfarm LLC, Windcurrents Windfarm, LLC	7.6	Wind															
Wind Woodstock	4/30/2034	30	Woodstock Wind Farm, LLC	10.2	Wind															
Louise Solar Project, LLC	6/30/2040	18.5	Louise Solar Project, LLC	50	Solar															
Poet, LLC	Various	MTM	Poet, LLC	0.375	Solar															
Fillmore County Solar Project, LLC	6/30/2040	18.5	Fillmore County Solar Project, LLC	30	Solar															

PROTECTED DATA ENDS]

Community Solar Gardens

In its September 17, 2014 ORDER APPROVING SOLAR-GARDEN PLAN WITH MODIFICATIONS in Docket No. E002/M-13-867 (the Community Solar Gardens (CSG) docket), the Commission directed the Company to "include information about its bill credits, as reported in its Annual Compliance Report in this docket, in the Company's annual FCA Annual Automatic Adjustment (AAA) Report, reflecting the same time period covered by the AAA report."[1]

At the end of 2024, there were 535 active Community Solar Gardens in-service and 32 of these came on-line during the 2024 reporting period. The location, start date, and number of subscriptions for these gardens are detailed in Part C, Attachment 9. Since bill credits do not begin until the first day of the month after the CSG receives permission to operate, there were a total of 523 gardens receiving bill credits during this reporting period. A total of $222,663,221 in CSG bill credits were included in this year's FCA. The corresponding subscribed and unsubscribed energy bill credits were $221,619,146 and $1,044,076, respectively. The CSG expenses included in the FCA are shown in Part C, Attachment 10. We note that total CSG expenses included in FCA recovery during the reporting period may vary from other CSG reporting due to the timing between production and recording ledger expenses.

To comply with the fuel clause treatment approved in Docket No. E002/M-13-867, the bill credits and unsubscribed energy are recorded as fuel purchases in FERC Account 555. To allocate the costs to jurisdiction, the Company first divides the costs into market and above market categories. To determine market costs, the Company reviews the solar garden production by hour and the corresponding LMP price at that hour. These costs are allocated to jurisdiction based on sales. Costs above market are directly assigned to the Minnesota fuel clause.

The following table based on FCA data from Part C, Attachment 10 shows the breakdown of the total Minnesota Community Solar Garden market and above market expenses in the 2024 reporting period:

[1] As outlined in our January 9, 2024 Compliance filing in Docket No. E002/CI-23-335, we have included CSG projects participating in the Department of Commerce's Low- and Moderate-Income Accessible Program.

	System	**MN Amount[2]**	**Estimated MN Retail Allocator**
Market	$42,626,854	$30,569,425	0.7171
Above Market	$180,036,368	$180,036,368	1.000000
Total	$222,663,221	$210,605,793	

Our Community Solar Garden program continues to grow, and we anticipate further growth over the coming years. The Company's most recent solar garden annual compliance report was submitted on April 1, 2024 in Docket No. E002/M-13-867, and the next report is due on April 1, 2025.

[2] $26,200 in solar gardens developer late fees were credited to the FCA. This credit has resulted in a net solar garden cost recovery of $180,010,168 during the reporting period.

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
1	Le Sueur	9/9/2015	0.036	5
2	Lincoln	4/25/2016	0.204	14
3	Ramsey	5/12/2016	0.125	8
4	Hennepin	8/22/2016	0.036	18
5	Chisago	12/14/2016	5	46
6	Dakota	12/14/2016	5	85
7	Chisago	12/15/2016	4	44
8	Carver	12/15/2016	5	583
9	Scott	12/19/2016	3	213
10	Dakota	12/20/2016	5	34
11	Stearns	12/21/2016	5	60
12	Dakota	12/22/2016	5	33
13	Stearns	1/4/2017	3	24
14	Stearns	1/5/2017	3	262
15	Goodhue	1/12/2017	4.86	45
16	Dakota	1/13/2017	5	33
17	Chisago	1/13/2017	3.888	33
18	Dakota	2/13/2017	5	206
19	Goodhue	2/13/2017	4	285
20	Carver	2/28/2017	4.86	36
21	Washington	3/10/2017	0.036	7
22	Wabasha	3/13/2017	3	161
23	Blue Earth	5/31/2017	3	19
24	Redwood	5/31/2017	3	54
25	Winona	5/31/2017	0.25	30
26	Rice	6/30/2017	5	255
27	Dodge	7/18/2017	5	438
28	Washington	7/18/2017	5	207
29	Olmsted	7/19/2017	5	401
30	Kandiyohi	8/14/2017	2	12
31	Pipestone	8/18/2017	2	50
32	Chisago	8/22/2017	3	23
33	Stearns	8/24/2017	2	28
34	Chippewa	8/29/2017	2	17
35	Dakota	8/31/2017	5	49
36	Pope	9/13/2017	5	51
37	Stearns	9/13/2017	2.188	28
38	Stearns	9/13/2017	4.86	50
39	Lincoln	9/14/2017	0.2	18
40	Sherburne	9/22/2017	5	179

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
41	Dodge	9/27/2017	4	38
42	Benton	9/29/2017	2	27
43	McLeod	10/25/2017	3	44
44	Chippewa	10/25/2017	3	57
45	Hennepin	10/25/2017	5	31
46	McLeod	10/26/2017	5	128
47	Pipestone	10/30/2017	5	65
48	Stearns	10/30/2017	3	39
49	Benton	10/30/2017	5	42
50	Wright	11/3/2017	5	1196
51	Stearns	11/9/2017	5	50
52	Wright	11/13/2017	5	1134
53	Stearns	11/16/2017	4	166
54	Nicollet	11/20/2017	5	37
55	Blue Earth	11/20/2017	5	57
56	Scott	11/30/2017	4.69	45
57	Scott	11/30/2017	0.7	7
58	Dakota	11/30/2017	2.7	133
59	Rice	11/30/2017	5	183
60	Stearns	12/13/2017	5	50
61	Chisago	12/13/2017	5	35
62	Carver	12/15/2017	5	64
63	Chisago	12/18/2017	5	30
64	Dodge	12/18/2017	5	84
65	Scott	12/20/2017	2.991	27
66	Carver	12/21/2017	4.361	50
67	Renville	12/28/2017	3	69
68	Washington	1/10/2018	5	85
69	Carver	1/16/2018	3	22
70	Le Sueur	1/18/2018	3	20
71	Dakota	1/23/2018	4.95	50
72	Wabasha	1/29/2018	4	27
73	Pipestone	1/31/2018	4.7	94
74	Sherburne	2/12/2018	3.25	324
75	Rice	2/14/2018	0.998	146
76	Le Sueur	2/23/2018	3	44
77	Carver	2/26/2018	1.996	287
78	Waseca	2/26/2018	5	73
79	Rice	2/28/2018	5	35
80	Le Sueur	2/28/2018	5	57

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
81	Washington	2/28/2018	4	590
82	Faribault	3/2/2018	1.84	22
83	Rice	3/2/2018	3	24
84	Steele	3/5/2018	3.4	221
85	Carver	3/6/2018	3	21
86	Chisago	3/13/2018	5	30
87	Carver	3/14/2018	0.998	143
88	Sherburne	3/14/2018	5	46
89	Pope	3/15/2018	5	398
90	Chippewa	3/25/2018	4	46
91	Benton	3/25/2018	2	18
92	Scott	3/28/2018	4.95	75
93	Goodhue	4/12/2018	0.8	127
94	Washington	4/13/2018	3	25
95	Pope	4/19/2018	3	268
96	Washington	4/20/2018	5	35
97	Goodhue	4/26/2018	0.998	121
98	Chisago	4/30/2018	3	21
99	Stearns	4/30/2018	5	61
100	Sherburne	4/30/2018	4	46
101	Goodhue	5/11/2018	1	27
102	Renville	5/16/2018	1	24
103	Renville	5/17/2018	1	21
104	Goodhue	5/22/2018	1	10
105	Blue Earth	5/30/2018	1	10
106	Steele	6/5/2018	1	7
107	Hennepin	6/6/2018	0.18	29
108	Lyon	6/15/2018	3	48
109	Rice	6/20/2018	1	18
110	Le Sueur	6/29/2018	3	24
111	Sherburne	6/29/2018	5	40
112	Watonwan	7/2/2018	0.25	23
113	Sherburne	7/13/2018	5	55
114	Washington	7/16/2018	2.5	18
115	Steele	7/18/2018	1	7
116	Goodhue	7/19/2018	5	42
117	Dakota	7/27/2018	5	45
118	Goodhue	7/30/2018	2	20
119	Chisago	8/1/2018	1	26
120	DOUGLAS	8/2/2018	5	267

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
121	Le Sueur	8/6/2018	5	393
122	Blue Earth	8/7/2018	3.54	475
123	Chisago	8/9/2018	5	39
124	Wright	8/14/2018	0.972	6
125	Benton	8/14/2018	4.95	35
126	Carver	8/16/2018	4	387
127	Wright	8/27/2018	5	394
128	Chisago	8/30/2018	1	11
129	Washington	9/4/2018	5	1379
130	Washington	9/7/2018	0.75	104
131	Goodhue	9/14/2018	1	12
132	Dakota	9/17/2018	0.75	10
133	Goodhue	9/19/2018	1	24
134	Waseca	9/27/2018	1	6
135	Chisago	9/28/2018	1	49
136	Chisago	9/28/2018	1	8
137	Hennepin	9/28/2018	0.32	25
138	Blue Earth	10/16/2018	5	43
139	Wright	10/17/2018	4	33
140	McLeod	10/25/2018	1	6
141	Waseca	10/25/2018	1	6
142	Washington	10/29/2018	4.875	50
143	Benton	10/30/2018	1	11
144	Waseca	11/1/2018	1	11
145	Chippewa	11/14/2018	1	136
146	Kandiyohi	11/14/2018	1	25
147	Pope	11/16/2018	1	18
148	Sherburne	11/16/2018	1	6
149	Chisago	11/26/2018	1	12
150	Chisago	11/27/2018	1	16
151	Wright	11/28/2018	5	40
152	Scott	11/28/2018	0.823	9
153	Hennepin	11/28/2018	0.527	76
154	Scott	11/28/2018	1	9
155	Chisago	11/28/2018	1	10
156	Chisago	11/28/2018	1	13
157	Chisago	11/29/2018	1	14
158	Sherburne	12/3/2018	5	60
159	Chisago	12/7/2018	1	8
160	Sherburne	12/10/2018	4.8	50

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
161	Chisago	12/11/2018	0.5	21
162	Stearns	12/17/2018	1	65
163	Benton	12/17/2018	1	10
164	Benton	12/17/2018	1	8
165	Chippewa	12/18/2018	1	14
166	Le Sueur	12/19/2018	1	12
167	Murray	12/20/2018	1	8
168	Murray	12/20/2018	1	8
169	Yellow Medicine	12/21/2018	5	142
170	Ramsey	1/8/2019	0.54	6
171	Dodge	1/9/2019	1	12
172	Hennepin	1/11/2019	5	693
173	Meeker	1/23/2019	0.76	9
174	Stearns	1/28/2019	0.324	10
175	Nicollet	1/31/2019	1	8
176	Waseca	2/13/2019	1	12
177	Chisago	2/27/2019	2	20
178	Stearns	3/4/2019	0.72	10
179	Stearns	3/4/2019	1	13
180	Blue Earth	3/5/2019	0.24	13
181	McLeod	3/12/2019	3	90
182	Washington	3/22/2019	1	392
183	Stearns	3/25/2019	1	11
184	Wabasha	3/26/2019	0.85	120
185	Pope	3/26/2019	1	18
186	Sherburne	3/28/2019	5	99
187	Pope	3/28/2019	1	17
188	Renville	3/29/2019	1	15
189	Goodhue	4/11/2019	5	485
190	Wright	4/15/2019	5	1015
191	Stearns	4/16/2019	1	13
192	Chisago	4/22/2019	3	229
193	Washington	4/22/2019	1	203
194	Rice	4/30/2019	1	7
195	Carver	5/1/2019	1	7
196	Lyon	5/3/2019	1	10
197	Benton	5/13/2019	5	257
198	Dodge	5/15/2019	1	96
199	Dodge	5/15/2019	0.4	73
200	Kandiyohi	5/21/2019	1	10

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
201	Chisago	5/21/2019	1	9
202	Wright	5/31/2019	5	161
203	Stearns	6/3/2019	5	50
204	Dakota	6/7/2019	5	40
205	Dakota	6/7/2019	5	35
206	Sibley	6/14/2019	3.25	70
207	Stearns	6/18/2019	3	45
208	Freeborn	6/18/2019	0.25	34
209	Chisago	7/3/2019	1	14
210	Carver	7/22/2019	1	9
211	Scott	7/24/2019	0.598	57
212	Carver	7/25/2019	1	9
213	Sherburne	7/26/2019	3	33
214	Hennepin	7/30/2019	0.18	21
215	Sherburne	7/31/2019	0.996	152
216	Dakota	8/6/2019	1	361
217	Rice	8/8/2019	1	48
218	Scott	8/13/2019	1	8
219	Chisago	8/16/2019	0.998	185
220	Stearns	8/16/2019	1	146
221	Stearns	8/16/2019	1	141
222	Wabasha	8/20/2019	1	149
223	Wabasha	8/20/2019	1	135
224	Winona	8/21/2019	5	194
225	Winona	8/22/2019	1	120
226	Wabasha	8/22/2019	1	115
227	Winona	8/22/2019	1	93
228	Chippewa	8/26/2019	1	22
229	Carver	8/29/2019	1	7
230	McLeod	8/30/2019	1	12
231	Chisago	9/3/2019	1	5
232	Waseca	9/6/2019	1	11
233	Olmsted	9/9/2019	1	7
234	Pope	9/11/2019	1	11
235	Pope	9/11/2019	1	9
236	Hennepin	9/18/2019	0.96	185
237	Rice	9/18/2019	1	13
238	Blue Earth	9/24/2019	0.62	36
239	Goodhue	9/27/2019	4.4	56
240	Blue Earth	9/27/2019	0.62	28

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
241	Rice	10/9/2019	1	15
242	Stearns	10/23/2019	1	25
243	Stearns	10/25/2019	4.75	76
244	Sherburne	10/29/2019	1	15
245	Scott	10/30/2019	0.4	10
246	Waseca	11/18/2019	0.996	144
247	Sherburne	11/26/2019	1	15
248	Stearns	12/3/2019	1	14
249	Meeker	12/11/2019	1	42
250	Dakota	12/11/2019	1	16
251	DOUGLAS	12/11/2019	1	26
252	Meeker	12/13/2019	1	166
253	Rice	12/13/2019	1	9
254	Pope	12/16/2019	1	13
255	Stearns	12/16/2019	1	10
256	Nicollet	12/18/2019	1	153
257	Blue Earth	12/18/2019	1	147
258	McLeod	12/18/2019	1	127
259	Chisago	12/19/2019	1	14
260	Stearns	12/23/2019	1	16
261	Sherburne	12/23/2019	1	14
262	Sherburne	12/26/2019	1	10
263	Stearns	12/27/2019	1	174
264	DOUGLAS	12/27/2019	1	148
265	McLeod	12/27/2019	1	10
266	Renville	12/30/2019	1	13
267	Sherburne	12/30/2019	0.94	8
268	Goodhue	12/31/2019	0.59	8
269	Winona	1/3/2020	1	156
270	Winona	1/3/2020	1	162
271	Stearns	1/13/2020	1	16
272	Rice	1/14/2020	1	10
273	Dakota	1/15/2020	1	8
274	Meeker	1/17/2020	1	8
275	Winona	2/12/2020	1	22
276	Goodhue	2/13/2020	1	27
277	Pope	2/17/2020	1	13
278	Hennepin	2/17/2020	0.29	7
279	Rice	2/20/2020	1	10
280	Goodhue	2/26/2020	1	20

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
281	Pope	2/26/2020	1	14
282	Waseca	2/27/2020	1	9
283	Goodhue	2/28/2020	1	199
284	Goodhue	2/28/2020	1	166
285	Sherburne	2/28/2020	1	21
286	Waseca	3/4/2020	1	10
287	Washington	3/9/2020	3	18
288	Goodhue	3/9/2020	1	170
289	Rice	3/20/2020	1	10
290	Sibley	3/26/2020	1	14
291	Dakota	3/26/2020	1	10
292	Sibley	4/3/2020	1	19
293	Olmsted	4/3/2020	1	9
294	Dodge	4/7/2020	1	13
295	DOUGLAS	4/9/2020	1	15
296	Olmsted	4/13/2020	1	11
297	Olmsted	4/16/2020	1	10
298	Rice	4/24/2020	0.96	114
299	Scott	4/27/2020	3	755
300	Rice	4/27/2020	1	16
301	Goodhue	4/30/2020	1	28
302	Chisago	5/19/2020	1	11
303	Benton	5/20/2020	1	10
304	Stearns	5/21/2020	1	6
305	Dodge	5/21/2020	1	11
306	Carver	5/28/2020	1	49
307	Pope	5/30/2020	1	27
308	Dakota	6/2/2020	1	233
309	Dakota	6/4/2020	1	234
310	Waseca	6/16/2020	1	9
311	Rice	6/17/2020	2	39
312	Winona	6/24/2020	1	17
313	Winona	6/24/2020	1	38
314	Benton	7/10/2020	1	18
315	Rice	7/13/2020	5	89
316	Rice	7/20/2020	4	101
317	McLeod	7/20/2020	4	36
318	Nicollet	7/30/2020	1	10
319	Goodhue	7/30/2020	1	17
320	Stearns	7/31/2020	1	15

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
321	Wright	7/31/2020	1	25
322	Le Sueur	7/31/2020	1	8
323	Sherburne	7/31/2020	1	27
324	Goodhue	8/18/2020	1	11
325	Sherburne	9/1/2020	1	11
326	Redwood	9/14/2020	0.86	32
327	Chisago	9/14/2020	1	10
328	Waseca	9/15/2020	1	14
329	Chippewa	9/16/2020	1	22
330	Redwood	9/16/2020	1	36
331	Waseca	9/21/2020	1	12
332	Steele	9/22/2020	1	9
333	Nicollet	9/22/2020	1	8
334	Redwood	9/28/2020	1	31
335	Washington	9/28/2020	1	19
336	Freeborn	9/29/2020	1	22
337	Wright	10/1/2020	1	8
338	Dodge	10/6/2020	1	14
339	Dakota	10/6/2020	1	7
340	Clay	10/8/2020	1	39
341	Clay	10/8/2020	1	36
342	Clay	10/8/2020	1	37
343	Clay	10/8/2020	1	30
344	Nicollet	10/8/2020	1	25
345	Benton	10/14/2020	1	9
346	Rice	10/15/2020	0.7	8
347	Kandiyohi	10/19/2020	1	14
348	Kandiyohi	10/19/2020	1	11
349	Washington	10/20/2020	1	79
350	Clay	10/21/2020	1	31
351	Goodhue	10/26/2020	1	9
352	Waseca	10/27/2020	1	10
353	Renville	10/29/2020	1	15
354	Freeborn	10/30/2020	1	53
355	Chippewa	10/30/2020	1	23
356	Benton	11/3/2020	1	94
357	Dakota	11/4/2020	1	11
358	Goodhue	11/5/2020	1	20
359	Olmsted	11/9/2020	1	12
360	Dodge	11/9/2020	1	18

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
361	Sherburne	11/10/2020	1	11
362	Dodge	11/16/2020	1	8
363	Goodhue	11/19/2020	1	9
364	Rice	11/19/2020	1	11
365	Dodge	11/23/2020	1	13
366	Winona	11/30/2020	1	22
367	Stearns	12/1/2020	1	12
368	Renville	12/4/2020	1	13
369	McLeod	12/4/2020	1	9
370	Lyon	12/7/2020	1	53
371	Chisago	12/9/2020	1	7
372	Stearns	12/9/2020	1	39
373	Carver	12/10/2020	1	82
374	Chisago	12/11/2020	1	9
375	Pope	12/14/2020	1	10
376	Pope	12/14/2020	1	8
377	Stearns	12/16/2020	1	8
378	Nicollet	12/17/2020	1	9
379	Rice	12/21/2020	1	75
380	Pope	12/21/2020	1	26
381	Pope	12/28/2020	1	51
382	McLeod	12/30/2020	1	77
383	Dodge	1/4/2021	1	19
384	Dodge	1/4/2021	1	35
385	Waseca	1/6/2021	1	17
386	Le Sueur	1/28/2021	1	14
387	Kandiyohi	2/2/2021	1	9
388	Blue Earth	3/2/2021	1	11
389	Stearns	3/22/2021	0.86	27
390	Rice	3/23/2021	0.83	11
391	Rice	3/25/2021	1	10
392	Redwood	3/31/2021	1	7
393	Redwood	3/31/2021	0.86	12
394	Waseca	4/7/2021	1	14
395	Benton	4/21/2021	1	9
396	Benton	4/22/2021	1	7
397	Sherburne	6/2/2021	1	224
398	Washington	6/8/2021	1	191
399	Steele	6/16/2021	1	10
400	Rice	7/9/2021	1	191

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
401	Wright	7/13/2021	4	255
402	Dodge	7/13/2021	0.78	25
403	Pope	7/20/2021	1	85
404	Renville	7/20/2021	1	125
405	Chisago	7/21/2021	1	9
406	Renville	7/21/2021	1	165
407	McLeod	7/21/2021	1	125
408	Chisago	8/3/2021	1	9
409	Chisago	8/3/2021	1	10
410	Pipestone	8/5/2021	1	41
411	Goodhue	8/13/2021	1	7
412	Benton	8/19/2021	0.7	113
413	Pope	9/1/2021	1	89
414	Le Sueur	9/2/2021	1	13
415	Pope	9/23/2021	1	10
416	Goodhue	9/28/2021	1	185
417	Le Sueur	9/29/2021	1	12
418	McLeod	10/12/2021	1	116
419	Le Sueur	10/22/2021	1	17
420	Blue Earth	11/30/2021	1	13
421	Renville	11/30/2021	1	73
422	Goodhue	11/30/2021	1	45
423	Chisago	12/8/2021	1	9
424	Chisago	12/8/2021	1	10
425	Chisago	12/16/2021	1	7
426	Wright	12/22/2021	1	55
427	Nicollet	2/16/2022	1	131
428	Waseca	3/10/2022	1	163
429	Waseca	4/20/2022	1	8
430	Yellow Medicine	4/28/2022	1	15
431	Renville	5/12/2022	1	71
432	Wabasha	5/31/2022	1	181
433	Blue Earth	6/1/2022	1	8
434	Winona	6/9/2022	1	139
435	Blue Earth	6/9/2022	1	55
436	Benton	6/10/2022	1	133
437	McLeod	8/5/2022	0.427	24
438	Dodge	8/11/2022	1	167
439	Redwood	8/24/2022	1	83
440	Dodge	8/26/2022	0.48	8

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
441	Chisago	8/31/2022	1	191
442	Lyon	9/8/2022	1	78
443	Dodge	9/9/2022	1	179
444	McLeod	9/28/2022	1	64
445	Renville	10/13/2022	1	29
446	Hennepin	11/10/2022	0.125	41
447	Renville	11/29/2022	1	212
448	Lyon	12/5/2022	1	172
449	Chippewa	12/6/2022	1	183
450	Murray	12/8/2022	1	155
451	DOUGLAS	12/9/2022	0.453	29
452	Ramsey	12/9/2022	0.2504	7
453	Le Sueur	12/9/2022	1	8
454	Sherburne	12/12/2022	1	206
455	Chippewa	12/13/2022	1	104
456	Sibley	12/14/2022	1	192
457	Renville	12/16/2022	1	57
458	Blue Earth	12/19/2022	1	226
459	Renville	12/19/2022	1	47
460	Wabasha	12/20/2022	1	129
461	Renville	12/20/2022	1	48
462	Goodhue	12/22/2022	1	71
463	Winona	12/28/2022	1	39
464	Renville	1/10/2023	1	71
465	Sibley	1/12/2023	1	121
466	Olmsted	2/21/2023	1	135
467	Chisago	3/28/2023	1	10
468	Chisago	5/1/2023	1	22
469	Wright	5/30/2023	1	145
470	Waseca	6/9/2023	1	10
471	Stearns	6/13/2023	1	17
472	Yellow Medicine	6/15/2023	1	50
473	Steele	6/19/2023	1	25
474	McLeod	6/19/2023	1	12
475	Renville	6/20/2023	1	45
476	Carver	6/21/2023	1	33
477	Nicollet	6/26/2023	1	60
478	Sibley	6/26/2023	0.96	236
479	Meeker	6/28/2023	1	195
480	Sherburne	7/19/2023	1	54

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
481	Blue Earth	9/6/2023	1	73
482	Lyon	9/13/2023	1	189
483	Blue Earth	9/14/2023	1	101
484	Pope	9/15/2023	1	111
485	Stearns	9/27/2023	1	33
486	Wabasha	10/25/2023	1	59
487	Wabasha	10/25/2023	0.999	8
488	Winona	10/25/2023	0.999	7
489	McLeod	10/30/2023	0.999	26
490	Goodhue	11/6/2023	0.999	10
491	Renville	11/15/2023	0.88	14
492	Chippewa	11/21/2023	0.8889	165
493	Stearns	11/22/2023	1	52
494	Chisago	11/30/2023	1	36
495	Chippewa	12/4/2023	0.999	112
496	Chisago	12/18/2023	0.8	25
497	Blue Earth	12/18/2023	0.999	93
498	Blue Earth	12/19/2023	0.6216	67
499	Rice	12/20/2023	0.999	29
500	Sherburne	12/20/2023	0.999	195
501	Renville	12/21/2023	0.999	50
502	Washington	12/21/2023	1	161
503	Renville	12/27/2023	0.999	126
504	Chisago	1/3/2024	1	35
505	Ramsey	1/8/2024	0.3	10
506	Meeker	1/26/2024	1	127
507	Carver	1/31/2024	0.999	46
508	Clay	4/24/2024	0.999	119
509	Scott	5/29/2024	1	340
510	McLeod	6/5/2024	1	230
511	Chippewa	6/26/2024	0.99	221
512	Benton	6/27/2024	1	213
513	Blue Earth	7/16/2024	1	209
514	Stearns	7/17/2024	1	178
515	Hennepin	7/23/2024	0.78	139
516	Washington	7/29/2024	1	127
517	Hennepin	8/8/2024	0.3125	38
518	Sherburne	8/30/2024	1	328
519	Renville	8/30/2024	1	132
520	Chippewa	8/30/2024	1	88

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2024)
521	Murray	9/4/2024	1	77
522	Goodhue	9/5/2024	1	333
523	Renville	9/10/2024	1	242
524	Stearns	11/5/2024	0.999	9
525	Murray	12/2/2024	1	0
526	Kandiyohi	12/3/2024	1	0
527	Redwood	12/13/2024	1	0
528	Stearns	12/16/2024	1	0
529	Lyon	12/17/2024	1	0
530	Waseca	12/18/2024	0.999	0
531	Sherburne	12/20/2024	0.999	0
532	Stearns	12/23/2024	0.999	0
533	Stearns	12/31/2024	0.975	0
534	Dodge	12/31/2024	0.975	0
535	Chippewa	12/31/2024	0.77	0

* Data represents subscriptions through November. Projects completed in December had yet to receive bill credits are therefore are not yet counted here.

2024 Minnesota Jurisdictional Solar Gardens Program Cost Recovery Through Fuel Clause Rider

		January 2024	February 2024	March 2024	April 2024	May 2024	June 2024	July 2024	August 2024	September 2024	October 2024	November 2024	December 2024	Total 2024
	System Portion of Bill Credits & Unsubscribed Energy Payments													
	Without Solar Gardens Developer Late Fees													
	Market Amount Allocated to All Jurisdictions													
[1]	Solar Gardens Subscribed Energy	$1,460,539	$2,735,671	$4,368,308	$3,080,423	$4,351,740	$6,259,436	$5,682,654	$6,803,779	$5,358,349	$3,857,316	$2,084,847	($4,461,543)	$41,581,517
[2]	Solar Gardens Unsubscribed Energy <40 KW	$0	$0	$0	$0	$0	$0	$0	$0	$79	$874	$35	$273	$1,261
[3]	Solar Gardens Unsubscribed Energy > 40 KW	$66,575	$69,619	$12,660	$71,825	$151,556	$45,239	$111,334	$84,532	$190,873	$81,274	$74,421	$84,168	$1,044,076
[4]	Total Costs (System) [1]+[2]+[3]	$1,527,114	$2,805,290	$4,380,968	$3,152,248	$4,503,296	$6,304,675	$5,793,989	$6,888,310	$5,549,300	$3,939,463	$2,159,303	($4,377,102)	$42,626,854
	Above Market Amount Recoverable in Minnesota Jurisdiction													
[5]	Minnesota Direct Assigned Above Market Amount	$5,483,977	$12,356,288	$17,010,032	$16,353,751	$21,343,124	$16,998,685	$18,516,058	$19,437,935	$19,408,814	$15,106,710	$7,002,827	$11,018,166	$180,036,368
[6]	**Total Bill Credits & Unsubscribed Energy Payments** [4]+[5]	**$7,011,091**	**$15,161,578**	**$21,391,000**	**$19,505,999**	**$25,846,421**	**$23,303,360**	**$24,310,047**	**$26,326,245**	**$24,958,114**	**$19,046,174**	**$9,162,130**	**$6,641,064**	**$222,663,221**
	Detailed Derivation of Solar Gardens Cost Recovery from Minnesota Retail Customers													
	Above Market Bill Credits Allocated to Minnesota Fuel Clause Recovery													
[7]	Solar Gardens Cost Recovery for MN FCA [5]	**$5,483,977**	**$12,356,288**	**$17,010,032**	**$16,353,751**	**$21,343,124**	**$16,998,685**	**$18,516,058**	**$19,437,935**	**$19,408,814**	**$15,106,710**	**$7,002,827**	**$11,018,166**	**$180,036,368**
	MWh Sales Weighting													
[8]	Minnesota Jurisdiction Retail MWh Subject to FCA	2,302,649	2,050,938	2,115,432	1,918,578	2,101,864	2,289,974	2,644,317	2,524,656	2,302,392	2,151,950	2,077,479	2,293,850	26,774,079
[9]	NSPM System MWh Sales Exclude Windsource & Renewable*Connect	2,697,375	2,387,393	2,472,396	2,234,037	2,421,552	2,645,500	3,067,938	2,934,216	2,659,236	2,490,288	2,423,478	2,687,878	31,121,287
[10]	Allocation Weighting [8]/[9]	85.3663%	85.9070%	85.5620%	85.8794%	86.7982%	86.5611%	86.1920%	86.0419%	86.5810%	86.4137%	85.7230%	85.3406%	86.0314%
	Market Bill Credits and Payments Allocated to MN Fuel Clause Recovery													
[11]	Market Amount Allocated to All Jurisdictions [4]	$1,527,114	$2,805,290	$4,380,968	$3,152,248	$4,503,296	$6,304,675	$5,793,989	$6,888,310	$5,549,300	$3,939,463	$2,159,303	($4,377,102)	$42,626,854
[12a]	Interchange Allocator	82.2460%	82.3736%	82.3396%	82.3371%	83.2951%	83.2856%	83.6828%	83.4372%	83.3524%	82.5552%	82.1727%	82.0479%	
[12b]	Allocation Weighting [10]	85.3663%	85.9070%	85.5620%	85.8794%	86.7982%	86.5611%	86.1920%	86.0419%	86.5810%	86.4137%	85.7230%	85.3406%	
[13]	Market Amount Allocated to Minnesota Jurisdiction [11]*[12]	**$1,072,192**	**$1,985,154**	**$3,086,454**	**$2,228,975**	**$3,255,823**	**$4,545,223**	**$4,179,083**	**$4,945,186**	**$4,004,781**	**$2,810,373**	**$1,521,033**	**($3,064,854)**	**$30,569,425**
	Total Solar Gardens Costs Recovery Included in MN Fuel Cost Charge													
[14]	Market and Above Market Allocated Amount [17]+[13]	**$6,556,169**	**$14,341,442**	**$20,096,487**	**$18,582,726**	**$24,598,948**	**$21,543,908**	**$22,695,141**	**$24,383,121**	**$23,413,595**	**$17,917,084**	**$8,523,860**	**$7,953,312**	**$210,605,793**
[15]	**Solar Gardens Developer Late Fees (Credit Back to MN Customer**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**($10,400)**	**($15,800)**	**($26,200)**
[16]	**Net Solar Gardens Costs Recovery Included in MN Fuel Cost Cha**	**$6,556,169**	**$14,341,442**	**$20,096,487**	**$18,582,726**	**$24,598,948**	**$21,543,908**	**$22,695,141**	**$24,383,121**	**$23,413,595**	**$17,917,084**	**$8,513,460**	**$7,937,512**	**$210,579,593**
	Market Bill Credits and Payments Allocated to Other Jurisdictions													
[17]	Cost Allocated to Other Jurisdictions (Market Portion Based on LMP) [4	$454,922	$820,136	$1,294,513	$923,272	$1,247,473	$1,759,452	$1,614,905	$1,943,124	$1,544,519	$1,129,090	$638,269	($1,312,248)	$12,057,429
	Direct Assigned Minnesota Cost Removed from System Cost													
[18]	Minnesota Direct Assigned Above Market Amount [5]	$5,483,977	$12,356,288	$17,010,032	$16,353,751	$21,343,124	$16,998,685	$18,516,058	$19,437,935	$19,408,814	$15,106,710	$7,002,827	$11,018,166	$180,036,368
[19]	Solar Gardens Developer Late Fees (Credit Back to MN Customers) [15]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($10,400)	($15,800)	($26,200)
[20]	Direct Assigned Minnesota Cost Removed from System Cost [18]+[19]	**$5,483,977**	**$12,356,288**	**$17,010,032**	**$16,353,751**	**$21,343,124**	**$16,998,685**	**$18,516,058**	**$19,437,935**	**$19,408,814**	**$15,106,710**	**$6,992,427**	**$11,002,366**	**$180,010,168**

FUEL PROCUREMENT POLICIES

A. Coal

Xcel Energy's coal procurement policy provides that coal and transportation services will be purchased at the lowest reasonable cost within the constraints of environmental regulations, supply reliability, operational compatibility, and consistency with Xcel Energy's inventory needs. The Company obtains its coal through a combination of long- and short-term contracts, including spot coal markets. A listing of current coal supply and transportation contracts and cost changes is shown on Part D, Attachments 3, 4, and 6.

Formal analysis of coal supply requirements for future years is performed on a regular basis. This multi-year analysis generally leads to solicitations for offers to supply unfulfilled requirements and/or bids to purchase coal. The solicitation process typically leads to purchases to fill the targeted percentages of near-term requirements based on a layered approach that varies from station to station. For example, purchases for the King Station are targeted at **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] When the transaction terms are attractive, Xcel Energy may fill different proportions of its future requirements. Xcel Energy continually reviews the current year's coal consumption to determine changes in coal requirements caused by such variables as weather, transportation availability, outage schedule revisions, capacity factors, and alternative electric sources. If there is an imbalance during an operational year between purchased coal supplies and station requirements, the additional fuel supply need is then corrected through such means as purchases based on spot coal market and transportation conditions at that time. Xcel Energy also monitors future years' needs on a continual basis.

The coal procurement strategy addresses the risk of supply interruption and exposure to market price fluctuations. Supply interruption can result from mine and/or transportation failures. Supply diversification is used to minimize the risk of mine failures and enhance market competition. Multiple suppliers are pre-qualified for each plant. Also, new contracts for coal supply generally do not include a specific destination, which allows coal to be moved to the generating facility where it is most needed. Supply interruptions resulting from transportation failures have been minimized through plant-specific inventory targets. When transportation performance degrades, the Company initiates close contact with our rail providers at all management levels to improve and restore service levels. Where necessary, other communication channels may be explored to exert all possible pressure to improve transportation service. **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

Fuel transportation service contracts are executed for various multiyear terms depending on market conditions, anticipated future market conditions, and plant delivery requirements. Proposed rates are vetted internally and externally through consultants and are compared to peers in the market to ensure price competitiveness. The final agreements for transportation of fuels may include minimum tonnage requirements.

B. Nuclear

The spot market price for uranium started 2025 at $73.00 per pound, which is a decrease of $18.00 as compared to the beginning of 2024. During the early part of the first quarter of 2025, the spot market price has ranged from $67.30 per pound to a high of $75.00 per pound in January. This market volatility is mainly due to geopolitical pressures, transportation challenges, disruption of supply from Niger, and the disruption of supply from Russia.

Overall spot market volume declined in 2024. Spot market volumes were volatile from month to month. The largest increase was in May. The months of August, September, and November experienced increased volumes. Term contracting trended lower in 2024. Term contracting volumes declined about 39.7 percent in 2024. Continued strength in reported long-term market prices, which have risen to $79.00 per pound in December of 2024 from $68.00 per pound in December of 2023, has resulted in several uranium mine operators restarting existing mines. While forecasted levels of uranium production have increased, continued growth in forecasted global demand has also increased. The world's forecasted uncovered requirements of 93.8 million pounds in 2030 rises to 227.4 million pounds by 2040 as new nuclear plants are completed and existing nuclear plants in Japan are being restarted. Throughout 2025 and continuing into 2026, uranium security and supply issues remain of concern given the impact of supply chain and transportation challenges due to geopolitical pressures, political instability in Niger, and Russia's on-going war in the Ukraine. Differences between supply and demand is projected to be covered by end user inventories in 2025. Spot market volume estimated at 45 million pounds of U3O8 for 2024 is below the 57 million pounds of U3O8 reported for 2023. Spot market volumes in 2025 are predicted to range from 41 to 81 million pounds of U3O8. Spot market prices for 2025 through 2026 are projected to increase at an average annual rate of about 1.0 percent from 2024. Spot market prices for 2026 through 2027 are projected to decrease at an average annual rate of about 0.8 percent from 2025. The current market analysis forecasts global supply and inventories meeting demand until 2028, with a small supply deficit projected in 2029 (5 million pounds). The current market analysis forecasts a global supply deficit relative to projected demand of between 5 million to 27 million pounds in the years 2029 through 2033. The total supply deficit relative to projected demand from 2029 through 2040 is 713 million pounds, which is 4 percent higher than 687 million in the same period last year,. These estimates will be contingent on the expansion of existing uranium production and new production capacity.

C. Natural Gas

The potential of additional Western sanctions against Russia, implementation of U.S. tariffs on Canadian and Chinese imports, and political instability in Niger in conjunction with existing U.S. legislation banning importation of enriched uranium from Russia, and an existing Russian reciprocal export ban, continue to provide uncertainty with regard to price impacts or supply interruptions. Numerous U.S. utilities have contracted for supply of enriched uranium from Russia beyond 2024. If there are additional sanctions that impact the supply of enriched uranium from Russia to customers in the U.S. or EU, either directly or indirectly through sanctions on the banking infrastructure, the price of uranium could continue to be significantly impacted. A list of current nuclear fuel components of service contracts is shown on Part D, Attachment 2.

In contracting for natural gas, a combination of baseload purchases, daily spot purchases, and storage are utilized to meet the portfolio requirements. The basic premise is that base load purchases are used to approximately meet the minimum daily portfolio requirements, and the incremental burns above the minimum requirements are met using a combination of daily spot purchases and storage.

D. Woody Biomass

Xcel Energy establishes woody biomass supply contracts with a diverse group of suppliers. Sources of woody biomass include waste products from lumber mills and wood products industries, chipped bark and limbs from municipal tree trimming operations, chipped slash from logging operations, chipped pallets and demolition debris diverted from landfills, as well as shredded creosote-treated railroad ties. All wood fuel is chipped to sizing specifications and delivered by truck to the plants. There are currently between 25 and 30 suppliers that provide wood fuel to two plants. Our practice has been to establish long-term relationships with a select group of local suppliers. The criteria for selection of suppliers are: 1) dependable supply, 2) consistent quality, and 3) reasonable pricing. By ensuring that these suppliers sustain viable small businesses, we in turn can be reasonably confident that we will receive consistent supplies of wood fuel to our plants. Contracts are typically executed with terms from 1 to 5 years. See Part D, Attachment 5 for a listing of the contracts, and Part D, Attachment 6 for a listing of year-over-year cost changes. We have been able to maintain biomass pricing for our power plants below pulpwood industry prices to avoid potential competition for woody biomass with the pulp and paper industry.

E. Refuse-Derived Fuel (RDF)

Xcel Energy has established five contracts for the supply of refuse-derived fuel (RDF) for three power plants (Red Wing and Wilmarth in Minnesota, and French Island in Wisconsin). See Part D, Attachment 5 for a listing of the contracts, and Part D, Attachment 6 for a listing of year-over-year cost changes. Four of the contracts provide for the delivery of processed RDF to two of the plants. Xcel Energy also has a service agreement with La Crosse County, Wisconsin, which provides for the processing of municipal solid waste (MSW) into RDF and combustion of the RDF at the French Island facility in La Crosse. Almost all of the county's MSW is processed and disposed at the Xcel Energy facility, with the exception of materials recovered for recycling, and non-combustible or non-recoverable materials and ash byproducts which are disposed in the County's landfill.

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PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Nuclear Fuel Components of Services for the Period of January through December 2024

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
	[PROTECTED DATA BEGINS			
1				
2				
3				
4				
5				
6				
				PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Nuclear Fuel Components of Services for the Period of January through December 2024

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
7				
8				
9				
10				
11				
12				
13				
				PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Nuclear Fuel Components of Services for the Period of January through December 2024

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
14				
15				
16				
17				
18				
19				
20				
21				
				PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Operations - State of Minnesota
Summary of Actions Taken to Minimize Cost

Coal Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity or Volume (million tons/year)	Contract Expiration Date
[PROTECTED DATA BEGINS				
1				
2				
4				
5				
6				
7				
8				
9				
10				
				PROTECTED DATA ENDS]

Transportation & Related Services Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
1				
2				
3				
4				
				PROTECTED DATA ENDS]

Wood and RDF Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
				PROTECTED DATA ENDS]

Wood and RDF Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
				PROTECTED DATA ENDS]

Wood and RDF Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
				PROTECTED DATA ENDS]

Cost Changes – January 1, 2024 to January 1, 2025

	Contract	Percent Change
[PROTECTED DATA BEGINS		
		PROTECTED DATA ENDS]

Cost Changes – January 1, 2024 to January 1, 2025

	Contract*	Percent Change
[PROTECTED DATA BEGINS		
		PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS		
		PROTECTED DATA ENDS]

*The majority of wood contracts are renewed with similar terms on an annual basis. The cost change represented is the related contract price on January 1, 2024 compared to the contract price on January 1, 2025.

DISPATCHING POLICIES AND PROCEDURES

The goal for Xcel Energy's dispatching policies and procedures is to provide our native load customers with low-priced reliable electric energy services. This goal is achieved primarily by closely monitoring our load and managing our generation system and purchased energy resources to provide the most economic loading of our own generation units in conjunction with leveraging the competitive wholesale energy and fuel markets. We discuss the Company's policies about self-commitment and self-scheduling of plants in our March 1 annual report filed in Docket No. E999/CI-19-704.

Xcel Energy devotes significant resources to managing our participation in MISO's wholesale energy market, which began operation on April 1, 2005 and increased functions on January 6, 2009. The MISO market altered the method by which we optimize our resources on behalf of our ratepayers, since all resources and load must be scheduled and cleared through MISO's Day Ahead and Real Time markets. However, this change has not altered our overarching goal of reliably providing our customers with the lowest possible energy cost. The Company continues to purchase energy in the the MISO Day Ahead and Real Time markets whenever the market price of purchased energy is below our avoided cost of production. Additionally, we continue to work with MISO to coordinate our efforts to obtain maximum value of our generation and purchased resources for customers.

The Company uses MISO Ancillary Services Market to co-optimize energy and ancillary services markets, resulting in a net benefit to ratepayers.

Another component of the Company's dispatching policy is forecasting how much renewable energy will be on the system at a given time. Xcel Energy uses a wind and solar forecast developed by DNV to estimate production from NSP system wind and solar facilities. Reductions in forecast error translate directly into a long-term decrease in fuel and purchased power costs because improved forecasts for renewable energy reduces the need for excessive commitment of thermal resources.

In summary, Xcel Energy's dispatching policies and procedures, while focused on reliable service, are influenced by a goal of lowest cost in an uncertain environment. Based on the best available information and analytical tools, Xcel Energy attempts to optimally offer our generation units to both minimize energy costs and mitigate the risks of higher than expected costs. These efforts include dispatching practices aimed at controlling wind curtailment costs. Given the potential uncertainties regarding load, generation plant availability, transmission limitations, and wholesale market prices, this requires continual analysis and rapid response to changing conditions, both on an expected (day ahead) and real-time basis.

FUEL SUPPLY

a. Nuclear Fuel

1. Nuclear fuel costs are economically competitive. The average total fuel cost at Prairie Island and Monticello was approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** mills/kWh in 2024.

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

3. Two contracts were executed in 2024. **[PROTECTED DATA BEGINS**

   PROTECTED DATA ENDS]

b. Fossil Fuel

1. Public documents released by the U.S. Energy Information Agency report average coal costs for utility consumption delivered in the U.S. was $2.51/MMBtu during 2023. (https://www.eia.gov/electricity/annual/html/epa_07_01.html)
   During this same period, Northern States Power Company – Minnesota's average delivered coal cost was **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. NSP's average delivered coal cost for 2022 was **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

2. NSP has re-emphasized its program to review or modify, as appropriate, coal procurement strategy **[PROTECTED DATA BEGINS**

   PROTECTED DATA

ENDS]

3. NSP maintained contract supplies, satisfied generation coal requirements, and produced fuel expense reductions.

4. Xcel Energy Services, Inc. negotiates terms with existing major coal suppliers on behalf of NSP **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

c. MISO Energy Charges

The Company actively checks, investigates, and disputes (when appropriate) calculations and the charges billed by MISO in the Day 2 energy market. From January through December 2024, the Company submitted two disputes for operating days in 2024.

NSP MISO Dispute Status

Disputed $ Amount			Dispute Status			
YEAR	Op Month	Operating Date	**GRANTED**	**DENIED**	**OPEN**	**TOTAL**
2024	2024-06	6/19/2024	$0.00	$11,646.26	$0.00	$11,646.26
2024	2024-06	6/19/2024	$0.00	$11,646.21	$0.00	$11,646.21
TOTAL			$0.00	$23,292.47	$0.00	$23,292.47

The total dollar amount disputed in the 2024 reporting period was $23,292.47, which is less than the 2023 reporting period of $5,011,350.13. There were two disputes, and both were denied. All other discrepancies not requiring a formal dispute are identified during our daily checkout process and generally resolved through the normal settlement process.

ENERGY CONSERVATION AND OPTMIZATION PROGRAM

Xcel Energy's Energy Conservation and Optimization Program (ECO) is designed to help our customers use energy wisely. The Company has developed more than 40 commercial and residential programs with the intent of providing customers the opportunity to lower their energy consumption and overall energy bills. As part of this portfolio, the Company has several electric load management programs available to customers including rate discounts for reducing electric loads on days with peak demand for electricity or rebates for participation in control events utilizing a smart thermostat.

Minn. Stat. §§ 216B.2401 and 216B.241 require certain Minnesota utilities, including Xcel Energy's electric utility, to invest in cost-effective conservation improvements through ECO. ECO programs are subject to regulation by the Minnesota Department of Commerce (Department). Currently, the Company offers a wide variety of programs to assist customers in implementing energy efficiency, load management, and efficient fuel switching measures, ranging from rebates for high efficiency equipment to home energy squad visits. By conserving energy (i.e. using less of it) and varying loads (i.e. interrupting a constant demand to lessen the peak kilowatt impact), customers will experience an overall reduction in their utility bills. Both methods mitigate the Company's power producing and purchasing needs. Moreover, both are considered in the Company's integrated resource planning process.

The Company is required to file with the Department every three years an ECO Triennial Plan detailing our goals, budgets and cost-effectiveness analyses for the next planning cycle. A detailed description and analysis of the Company's electric conservation policy and programs may be found in the Company's current 2024-2026 ECO Triennial Plan,[1] which was filed on June 29, 2023 and approved on December 1, 2023.[2]

On April 1 of each year, the Company is required to file with the Department an annual Status Report, which details the cost-effectiveness and spending for the prior year's program. The Deputy Commissioner issued approval of the Company's 2023 Status Report on July 8, 2024.[3]

[1] Minn.Stat. §216B.241 was adjusted in 2021 to enact changes to the Conservation Improvement Plan to modernize its scope to include additional load management technologies and beneficial electrification. This change is under the Energy Conservation and Optimization Act or ECO.
[2] Docket No. E,G002/CIP-23-92
[3] Docket No. E,G002/CIP-20-473

OTHER ACTIONS TO MINIMIZE COSTS

The Company continues to actively represent the interests of its Minnesota electric customers before national regulatory agencies to minimize the cost of wholesale electric supplies and third party transmission services to be recovered from Minnesota retail electric customers. The Company does this as an individual intervenor, through intervenor groups such as the MISO Transmission Owners (TOs), and through its membership in the Edison Electric Institute (EEI), which actively represents its members in major policy proceedings such as Federal Energy Regulatory Commission (FERC) rulemakings.

1. PARTICIPATION IN THE MISO TRANSMISSION OWNERS COMMITTEE

Northern States Power Company Minnesota (NSPM) and Northern States Power Company Wisconsin (NSPW) are transmission-owning members of MISO. NSPM and NSPW (jointly, the NSP Companies)[1] participate in the MISO Transmission Owning Committee (TOC). Not all MISO transmission-owning companies participate in the TOC.

The MISO TOC members jointly intervene in numerous FERC and other proceedings. The MISO TOC members own a substantial portion of the transmission facilities subject to MISO functional control, representing approximately two-thirds of all load in the MISO footprint. Other Minnesota entities that are MISO TOC members include Great River Energy, Minnesota Power, Otter Tail Power Company, Southern Minnesota Municipal Power Agency, ITC Midwest, LLC, Minnesota Municipal Power Agency, and Central Minnesota Municipal Power Agency. NSPM is also a participant on the Transmission Owners Tariff Working Group, which makes recommendations to the TOC on certain rate and revenue distribution changes pursuant to the MISO Transmission Owners Agreement (TOA). Xcel Energy representatives also participate in all other MISO committees, such as the Market Sub-Committee, Planning Advisory Committee, Reliability Sub-Committee and Regional Criteria and Benefits Working Group. These committees are critical to ensuring the development of transmission system additions that achieve maximum efficiency benefits.

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[1] The Company and NSPW are jointly referred to as the "NSP Companies," and their integrated electric generation and transmission system is referred to as the "NSP System."

OTHER ACTIONS TO MINIMIZE COSTS

2. SIGNIFICANT MISO DEVELOPMENTS/ACTIONS

The Company has been active in a number of proceedings before the FERC. To the extent the Department or the Commission or another stakeholder desires information related to specific proceedings, the Company will provide the additional information upon request.

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

December 23, 2024

Lindsey Simpson
Deloitte & Touche LLP
50 South Sixth Street, Suite 2800
Minneapolis, MN 55402

RE: 2024 ANNUAL AUTOMATIC ADJUSTMENT (AAA) CHARGES REPORT – ELECTRIC OPERATION
DOCKET NO. E002/AA-23-153

Dear Ms. Simpson:

The purpose of this letter is to notify Deloitte & Touche LLP, external auditor for Northern States Power Company, doing business as Xcel Energy, of certain requirements established by the Minnesota Public Utilities Commission for the upcoming Annual Automatic Adjustment (AAA) of Charges Report – Electric Operations and True-Up Report. The Company's 2024 Electric AAA and True-Up Report will be filed with the Commission and Minnesota Department of Commerce – Division of Energy Resources by March 1, 2025. This report covers the 2024 calendar year period per the Commission's December 19, 2017 and June 12, 2019 Orders in Docket No. E999/CI-03-802, which changed the process for how fuel clause factors are set and reported in Minnesota.

Scope of the Electric AAA Report

The Company's Electric AAA and True-Up Report, among other things, will provide detailed results of the Company's fuel clause for the reporting period January – December 2024. The Company implemented monthly fuel rates January 1, 2024, as approved per the Commission's November 9, 2023 Order in Docket No. E002/AA-23-153. Monthly rates were later adjusted pursuant to the Company's September 30, 2024 filing in Docket No. E002/AA-23-153. Those rates took effect on November 1, 2024. Appendix A to this letter shows the implemented 2024 monthly factors. The Department will prepare comprehensive analyses of the AAA and True-Up Reports filed by all regulated electric utilities, and the Commission will conduct a hearing to review and act on the Reports and the Department's recommendations.

AAA Report Independent Audit Requirements

The rules governing the automatic adjustment clauses for Minnesota electric utilities and AAA Reports are set forth in Minn. Rule 7825.2600 *et seq*. Minn. Rule 7825.2820 requires an annual independent auditor's report evaluating the utility's accounting for automatic adjustments for the reporting year. Pursuant to the Commission's December 19, 2017 and June 12, 2019 Orders in Docket No. E999/CI-03-802, Xcel Energy's Fuel Clause Adjustment (FCA) in 2024 is based on an annual forecast of system energy costs and sales as approved by the Commission that reflects the following:

1. The fuel costs are unbundled from the energy charges (or base rates). The Base Cost of Energy embedded in the energy charges is listed separately with the monthly adjustments as "Fuel Cost Charge" line item on bill; and
2. Instead of a single factor, the monthly fuel cost factors are differentiated by six customer class categories.

Per the Commission's November 5, 2019 Order in Docket No. E999/CI-03-802, the Company no longer recovers energy-related costs via its base cost of energy.

The Fuel Clause Rider as defined in the Company's Minnesota Electric Rate Book - MPUC No. 2, Sheet Nos. 5-91, 5-91.1, 5-91.2 and 5-91.3 also include variances authorized by the MPUC. We note the dockets in which these variances were approved in Appendix B.

For the twelve months ending December 31, 2024, computations of the monthly fuel clause adjustment factors also reflected the MISO Day 2 and ASM charges recovery, wind contracts curtailment payments, renewable energy purchase agreements, Windsource and Renewable*Connect exemption, and end-of-life nuclear fuel accrual. Please see Appendix B for a list of dockets in which these additional items were approved.

The 2024 Electric AAA and True-Up Report also covers the refunds in the FCA true-up pursuant to the ongoing Asset Based Margin Sharing Program as defined in the Company's Minnesota Electric Rate Book—MPUC No. 2, Sheet No. 5-91.2.[1]

AAA Report Additional Independent Audit Requirements

In compliance with the Commission's March 20, 2002 Order in Docket No. E002/M-01-1953, the Company is required to submit a written request that its external auditors specifically examine the wholesale electric transactions that use gas financial

[1] Pursuant to the Commission Order in the Company's 2010 rate case (Docket No. E002/GR-10-971) dated May 14, 2012, the Non-Asset Based Margins can no longer be credited through the FCA.

instruments to hedge the price risk associated with those transactions. In preparing the auditor report to be submitted with the Company's 2024 Electric AAA and True-Up Report to be filed by March 1, 2025, the Company's external auditors should include a statement certifying the following:

- The accounting separation of retail and wholesale financial instruments is implemented appropriately; and
- An audit has been performed to ensure no wholesale electric financial instrument gains or losses are recorded in Account 555 or in Account 804.

The Commission's July 21, 2017 Order in Docket No. E999/AA-15-611 requires that the independent auditor report includes the following:

- comparison of the documentation in support of payments and invoices received from energy suppliers;
- comparison of the base costs of power approved by the Commission to the bases used by the utility;
- recalculation of the billing adjustment charge (credit) per kWh charged to customers for purchased power for the entire applicable period by customer class;
- comparison of the accounting records for the revenues billed to customers for energy delivered for the relevant period to the total sales of electric energy;
- on a test basis, an examination of individual billings in each customer class by recalculating the automatic adjustment of charges and credits and tracing to individual customers' subsidiary records to ensure that the calculated credit or charge was correctly recorded;
- an examination of any corrections to FCA charges or other billing errors;
- a reconciliation of total revenue and cost of power in the utility's general ledger; and
- a recalculation of any true-up, and tracing of the related revenue and expense amounts to the utility's accounting records.

Audit Completion Date

We are requesting the completion of this audit by no later than February 28, 2025. We will gladly work with you to establish a revised schedule if necessary. The Deloitte & Touche independent audit report should be provided to Lisa Peterson, Director, Regulatory Pricing & Analysis, 414 Nicollet Mall – 401 7th Floor, Minneapolis, Minnesota 55401.

Thank you for your attention to this matter. Please do not hesitate to call me at

612-330-5570 with any questions. We will schedule a follow-up meeting to ensure that all the audit requirements are understood.

Sincerely,

/s/

REBECCA D. EILERS
MANAGER, REGULATORY AFFAIRS

cc: Lisa Peterson
Hui Chen

Xcel Energy

Northern States Power Company

Minnesota Retail Electric Fuel Cost Charges ($/KWh)

UPDATED 11/1/2024

FUEL COST CHARGE ($/kWh)	Residential	C&I Non-Demand	C&I Demand Non-TOD	C&I Demand TOD On-Peak	C&I Demand TOD Off-Peak	Outdoor Lighting	C&I Demand General Time of Use Service Pilot Program On-Peak	C&I Demand General Time of Use Service Pilot Program Base	C&I Demand General Time of Use Service Pilot Program Off-Peak
2024 Forecast									
FAF Ratio *	1.0192	1.0183	1.0030	1.2746	0.8001	0.7659	1.3230	1.0665	0.5239
January									
Forecast	$0.03308	$0.03305	$0.03256	$0.04135	$0.02599	$0.02488	$0.04292	$0.03461	$0.01705
2023 Proposed Reduction	($0.00220)	($0.00220)	($0.00217)	($0.00275)	($0.00173)	($0.00165)	($0.00286)	($0.00230)	($0.00113)
Total	$0.03088	$0.03085	$0.03039	$0.03860	$0.02426	$0.02323	$0.04006	$0.03231	$0.01592
February									
Forecast	$0.03624	$0.03621	$0.03567	$0.04531	$0.02846	$0.02725	$0.04703	$0.03792	$0.01865
2023 Proposed Reduction	($0.00247)	($0.00247)	($0.00244)	($0.00310)	($0.00194)	($0.00186)	($0.00322)	($0.00259)	($0.00127)
Total	$0.03377	$0.03374	$0.03323	$0.04221	$0.02652	$0.02539	$0.04381	$0.03533	$0.01738
March									
Forecast	$0.03892	$0.03889	$0.03830	$0.04867	$0.03056	$0.02926	$0.05052	$0.04073	$0.02002
2023 Proposed Reduction	($0.00233)	($0.00233)	($0.00229)	($0.00292)	($0.00183)	($0.00176)	($0.00303)	($0.00244)	($0.00120)
Total	$0.03659	$0.03656	$0.03601	$0.04575	$0.02873	$0.02750	$0.04749	$0.03829	$0.01882
April									
Forecast	$0.04222	$0.04219	$0.04155	$0.05279	$0.03316	$0.03174	$0.05480	$0.04418	$0.02173
2023 Proposed Reduction	($0.00267)	($0.00267)	($0.00262)	($0.00334)	($0.00210)	($0.00200)	($0.00347)	($0.00279)	($0.00137)
2023 True-Up Refund	($0.00392)	($0.00392)	($0.00386)	($0.00491)	($0.00308)	($0.00295)	($0.00509)	($0.00411)	($0.00202)
Total	$0.03563	$0.03560	$0.03507	$0.04454	$0.02798	$0.02679	$0.04624	$0.03728	$0.01834
May									
Forecast	$0.04485	$0.04481	$0.04414	$0.05608	$0.03523	$0.03372	$0.05820	$0.04693	$0.02309
2023 Proposed Reduction	($0.00247)	($0.00247)	($0.00244)	($0.00310)	($0.00195)	($0.00186)	($0.00321)	($0.00259)	($0.00127)
2023 True-Up Refund	($0.00362)	($0.00361)	($0.00356)	($0.00452)	($0.00284)	($0.00272)	($0.00470)	($0.00379)	($0.00186)
Total	$0.03876	$0.03873	$0.03814	$0.04846	$0.03044	$0.02914	$0.05029	$0.04055	$0.01996
June									
Forecast	$0.04185	$0.04181	$0.04118	$0.05232	$0.03286	$0.03146	$0.05431	$0.04379	$0.02153
2023 Proposed Reduction	($0.00216)	($0.00216)	($0.00212)	($0.00270)	($0.00170)	($0.00163)	($0.00281)	($0.00226)	($0.00111)
2023 True-Up Refund	($0.00316)	($0.00316)	($0.00311)	($0.00395)	($0.00248)	($0.00237)	($0.00410)	($0.00331)	($0.00162)
Total	$0.03653	$0.03649	$0.03595	$0.04567	$0.02868	$0.02746	$0.04740	$0.03822	$0.01880
July									
Forecast	$0.04244	$0.04240	$0.04177	$0.05309	$0.03330	$0.03188	$0.05511	$0.04441	$0.02178
2023 Proposed Reduction	($0.00185)	($0.00185)	($0.00183)	($0.00232)	($0.00145)	($0.00140)	($0.00241)	($0.00194)	($0.00095)
2023 True-Up Refund	($0.00272)	($0.00272)	($0.00268)	($0.00340)	($0.00214)	($0.00204)	($0.00353)	($0.00285)	($0.00140)
Total	$0.03787	$0.03783	$0.03726	$0.04737	$0.02971	$0.02844	$0.04917	$0.03962	$0.01943
August									
Forecast	$0.04143	$0.04139	$0.04077	$0.05182	$0.03252	$0.03113	$0.05379	$0.04336	$0.02128
2023 Proposed Reduction	($0.00194)	($0.00193)	($0.00190)	($0.00242)	($0.00152)	($0.00146)	($0.00251)	($0.00203)	($0.00099)
2023 True-Up Refund	($0.00284)	($0.00284)	($0.00280)	($0.00356)	($0.00223)	($0.00214)	($0.00369)	($0.00298)	($0.00146)
Total	$0.03665	$0.03662	$0.03607	$0.04584	$0.02877	$0.02753	$0.04759	$0.03835	$0.01883
September									
Forecast	$0.03947	$0.03944	$0.03885	$0.04937	$0.03099	$0.02966	$0.05124	$0.04131	$0.02029
2023 True-Up Refund	($0.00570)	($0.00569)	($0.00561)	($0.00713)	($0.00447)	($0.00428)	($0.00740)	($0.00596)	($0.00293)
Total	$0.03377	$0.03375	$0.03324	$0.04224	$0.02652	$0.02538	$0.04384	$0.03535	$0.01736
October									
Forecast	$0.03813	$0.03809	$0.03752	$0.04768	$0.02993	$0.02865	$0.04949	$0.03990	$0.01960
2023 True-Up Refund	($0.00605)	($0.00605)	($0.00596)	($0.00757)	($0.00475)	($0.00455)	($0.00786)	($0.00634)	($0.00311)
Total	$0.03208	$0.03204	$0.03156	$0.04011	$0.02518	$0.02410	$0.04163	$0.03356	$0.01649
November									
Forecast	$0.03455	$0.03452	$0.03400	$0.04320	$0.02713	$0.02597	$0.04484	$0.03615	$0.01777
2023 True-Up Refund	($0.00612)	($0.00611)	($0.00602)	($0.00765)	($0.00480)	($0.00460)	($0.00794)	($0.00640)	($0.00314)
2024 Mid-Year Adjustment	($0.00745)	($0.00744)	($0.00733)	($0.00931)	($0.00585)	($0.00560)	($0.00967)	($0.00779)	($0.00383)
Total	$0.02098	$0.02097	$0.02065	$0.02624	$0.01648	$0.01577	$0.02723	$0.02196	$0.01080
December									
Forecast	$0.03225	$0.03222	$0.03173	$0.04032	$0.02532	$0.02424	$0.04185	$0.03374	$0.01660
2023 True-Up Refund	($0.00559)	($0.00558)	($0.00550)	($0.00698)	($0.00438)	($0.00420)	($0.00725)	($0.00584)	($0.00287)
2024 Mid-Year Adjustment	($0.00681)	($0.00680)	($0.00670)	($0.00851)	($0.00535)	($0.00512)	($0.00883)	($0.00712)	($0.00351)
Total	$0.01985	$0.01984	$0.01953	$0.02483	$0.01559	$0.01492	$0.02577	$0.02078	$0.01022
Average	**$0.03278**	**$0.03275**	**$0.03226**	**$0.04099**	**$0.02574**	**$0.02464**	**$0.04254**	**$0.03430**	**$0.01686**

* FAF Ratio effective January 1, 2024.

2023	Residential	C&I Non-Demand	C&I Demand Non-TOD	C&I Demand TOD On-Peak	C&I Demand TOD Off-Peak	Outdoor Lighting	C&I Demand General Time of Use Service Pilot Program On-Peak	C&I Demand General Time of Use Service Pilot Program Base	C&I Demand General Time of Use Service Pilot Program Off-Peak
January*	$0.03316	$0.03358	$0.03254	$0.04066	$0.02663	$0.02601			
February*	$0.03615	$0.03661	$0.03546	$0.04435	$0.02901	$0.02833	$0.04482	$0.03803	$0.01982
March*	$0.04273	$0.04327	$0.04193	$0.05243	$0.03429	$0.03349	$0.05298	$0.04497	$0.02343
April*	$0.04761	$0.04822	$0.04671	$0.05839	$0.03823	$0.03734	$0.05901	$0.05010	$0.02616
May*	$0.04881	$0.04942	$0.04788	$0.05986	$0.03919	$0.03827	$0.06048	$0.05135	$0.02681
June*	$0.05107	$0.05172	$0.05011	$0.06266	$0.04100	$0.04004	$0.06331	$0.05374	$0.02803
July *#	$0.04190	$0.04243	$0.04111	$0.05141	$0.03362	$0.03284	$0.05194	$0.04408	$0.02297
August *#	$0.04168	$0.04220	$0.04089	$0.05114	$0.03343	$0.03266	$0.05168	$0.04385	$0.02283
September **#	$0.03562	$0.03607	$0.03494	$0.04369	$0.02859	$0.02792	$0.04415	$0.03747	$0.01954
October	$0.03881	$0.03930	$0.03808	$0.04761	$0.03115	$0.03043	$0.04811	$0.04084	$0.02129
November *	$0.03335	$0.03377	$0.03271	$0.04091	$0.02676	$0.02614	$0.04134	$0.03509	$0.01829
December	$0.03303	$0.03345	$0.03241	$0.04051	$0.02652	$0.02591	$0.04093	$0.03475	$0.01815
Average	$0.04033	$0.04084	$0.03956	$0.04947	$0.03237	$0.03162	$0.05080	$0.04312	$0.02248

*Included 2021 True-Up Recovery ** Included 2022 True-Up Recovery #Reflected $10M Reduction

Average for TOU tariff based on Feb 2023 - Dec 2023.

Appendix B

New Orders issued or new activities are underlined

The Fuel Clause Rider as defined in the Company's Minnesota Electric Rate Book - MPUC No. 2, Sheet Nos. 5-91, 5-91.1, 5-91.2 and 5-91.3 also include variances authorized by the MPUC. These variances were approved in the following dockets.

- Wind, Biomass and Others – E002/M-95-244, E002/M-96-934, E,G002/M-97-985, E002/M-17-530, E002/M-17-531, E002/M-17-532, E002/M-17-551, and E002/M-17-694
- Fuel Clause Reform – E999/CI-03-802, Orders dated December 19, 2017, June 12, 2019, and November 5, 2019
- 2023 Fuel Forecast and Factors – E002/AA-22-179, Order dated December 5, 2022, Rate Adjustment filing dated May 21, 2023, Rate Adjustment filing dated November 21, 2023, <u>True-Up Report filed March 1, 2023, Compliance filed April 1, 2024, Order dated November 15, 2024, and Compliance dated November 26, 2024</u>
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- WM Renewable Energy, LLC, E002/M-10-161, Order dated April 30, 2010
- Big Blue, LLC, Amendment approved in E002/M-13-1002, Order dated February 27, 2014.
- Hilltop, E002/M-08-47, Notice of Approval dated February 15, 2008
- Valley View, E002/M-08-1235, Order dated March 9, 2009
- Ridgewind, E002/M-08-1428, Notice of Approval dated January 2, 2009
- Moraine II, Amendment approved in E002/M-19-58, Order dated March 25, 2019
- Ewington Energy Systems LLC, E002/M-06-1472, Notice of Approval dated November 30, 2006
- Uilk Wind Farm, LLC, E002/M-08-1502, Notice of Approval dated February 6, 2009
- Prairie Rose Wind, LLC, E002/M-11-713, Order dated December 28, 2011
- Diamond K Dairy, E002/M-10-486, Order dated August 26, 2010
- School Sisters, E002/M-15-619, Order dated September 14, 2015
- Aurora Solar, E002/M-15-330, Order dated August 2, 2015
- Marshall and NorthStar Solar, E002/M-14-162, Order dated March 24, 2015
- Slayton Solar, E002/M-11-490, Order dated September 14, 2011
- Dragonfly Solar, E002/M-17-561, Order dated October 12, 2017
- University of Minnesota South East Plant, E002/M-20-39, Order dated April 10, 2020
- Crowned Ridge and Clean Energy #1 – E002/M-16-777, Order dated September 1, 2017
- Dakota Range III – E002/M-18-765, Order dated July 19, 2019
- St. Paul Cogeneration – E002/M-21-590, Order dated January 24, 2022

- WindSource Exemption – E002/M-01-1479, E002/M-09-1177, Order dated June 21, 2010

- End-Of-Life Nuclear Fuel Accrual – E002/M-05-1648
- Community Solar Gardens Program – E002/M-13-867, Order dated May 30, 2024
- Renewable*Connect Government Program – E002/M-15-985
- Renewable*Connect – Docket No. E002/M-19-33
- Renewable*Connect – Docket Nos. E002/M-19-33 and E002/M-21-222, Order dated May 18, 2023
- Solar Energy Standard Exemption – E002/M-17-425, Order dated October 12, 2017
- Acquisition of Community Wind North and Jeffers Wind Facilities – E002/PA-18-777, Order dated December 3, 2019
- Becker Land Sale – E002/PA-23-110, Order dated April 12, 2023
- Red Wing Land Sale – E002/PA-23-118, Order dated May 2, 2023
- General Time of Use Service Pilot Program – Docket No. E002/M-20-86, Order dated February 1, 2023
- Legislative Changes to Community Solar Gardens – Docket No. E002/CI-23-335, Order dated December 28, 2023
- 2023-2024 Natural Gas Annual Automatic Adjustment of Charges and True-Up – Docket Nos. G002/AA-24-138 and G002/AA-304, Report filed September 3, 2024

Northern States Power Company, a Minnesota corporation

Schedule of Fuel Adjustment Clause Factors of Northern States Power Company, a Minnesota corporation, for the period from January 1, 2024 to December 31, 2024, and Independent Accountant’s Report on Applying Agreed-Upon Procedures

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INDEPENDENT ACCOUNTANT'S REPORT

To the Board of Directors of
Northern States Power Company, a Minnesota corporation

We have performed the procedures enumerated below, on Northern States Power Company, a Minnesota corporation's (the "Company") Schedule of Fuel Adjustment Clause Factors filed with the Minnesota Public Utilities Commission (the "Commission"), covering the period from January 1, 2024 to December 31, 2024, in accordance with the Commission Rules 7825.2700 to 7825.2820 governing automatic adjustment of energy charges, and with the Fuel Clause Riders and Dockets as defined on Sheet Nos. 5-91, 5-91.1, 5-91.2, and 5-91.3 of the Company's tariff (the "subject matter"). The Company is responsible for the subject matter.

The Company has agreed to and acknowledged that the procedures performed are appropriate to meet the intended purpose of assisting the Company and the Commission (each and collectively, the "specified parties") in evaluating the subject matter from January 1, 2024 to December 31, 2024.

We make no representation regarding the appropriateness of the procedures either for the purpose for which our report has been requested or for any other purpose. Accordingly, this report may not be suitable for either the purpose of which this report has been requested or for any other purpose. The procedures performed may not address all the items of interest to a user of this report and may not meet the needs of all users of this report and, as such, users are responsible for determining whether the procedures performed are appropriate for their purposes. The procedures performed are specified in Commission Rules 7825.2700 to 7825.2820 governing automatic adjustment of energy charges.

Our procedures and findings are as follows:

a. We compared the documentation in support of payments and invoices received from energy suppliers for the period from January 1, 2024 to December 31, 2024 for 24 selections related to energy costs made during our procedures and found them to be in agreement.

b. We compared the base costs of power, approved by the Commission, to the base costs of power used by the Company for the period from January 1, 2024 to December 31, 2024 and found them to be in agreement.

c. We recalculated the billing adjustment charge (credit) per kWh charged to customers for purchased power for the period from January 1, 2024 to December 31, 2024, by customer class, and noted no exceptions between our recalculation and the Company's reported adjustment.

d. We compared the accounting records for the revenues billed to customers for energy delivered to the total sales of electric energy for the period from January 1, 2024 to December 31, 2024 and found them to be in agreement.

e. We randomly selected 24 individual billings across each of the customer class categories for the period from January 1, 2024 to December 31, 2024 and recalculated the automatic adjustment of charges and credits and traced to individual customer's subsidiary records to ensure that the calculated credit or charge was correctly recorded, noting no exceptions.

f. We did not identify any corrections to Fuel Adjustment Clause charges or other billing errors for the period from January 1, 2024 to December 31, 2024.

g. We reconciled total revenue and the cost of power for the period from January 1, 2024 to December 31, 2024 to the Company's general ledger and found them to be in agreement, when considering applicable reconciling items, with the Fuel Adjustment Clause Factors calculation underlying detail.

h. We have recalculated the true-up calculation and have traced the related revenue and expense amounts for the period from January 1, 2024 to December 31, 2024 to the company's accounting records and found them to be in agreement with the amounts used in the true-up calculation.

i. We selected a sample of 12 accounting records and through inspection we identified no exceptions with the accounting separation of retail and wholesale financial instruments.

j. We inspected vendor invoices and traced gains and losses to the accounting records for one selection to determine if any wholesale electric financial instrument gains or losses were recorded in accordance with the Federal Energy Regulatory Commission Uniform System of Accounts ("account" or "accounts") account 555 or account 804 and we didn't identify any such gains or losses as mentioned above in these accounts.

We were engaged by the Company to perform this agreed-upon procedures engagement and conducted our engagement in accordance with attestation standards established by the American Institute of Certified Public Accountants. We were not engaged to and did not conduct an examination or review engagement, the objective of which would be the expression of an opinion or conclusion, respectively, on the subject matter. Accordingly, we do not express such an opinion or conclusion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you.

We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements related to our agreed-upon procedures engagement.

This report is intended solely for the information and use of the Company and the Commission and is not intended to be, and should not be used by anyone other than the specified parties.

Deloitte & Touche LLP

February 28, 2025

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION

STATE OF MINNESOTA RETAIL ELECTRIC CUSTOMERS

SCHEDULE OF FUEL ADJUSTMENT CLAUSE FACTORS

FOR THE PERIOD FROM JANUARY 1, 2024 TO DECEMBER 31, 2024 (DOLLAR PER KWH)

	Residential	C&I Non-Demand	C&I Demand			Outdoor Lighting	General Time of Use Service Pilot Program		
			Non-TOD	TOD					
				On-Peak	Off-Peak		On-Peak	Base	Off-Peak
January 1, 2024	$ 0.03088	$ 0.03085	$ 0.03039	$ 0.03860	$ 0.02426	$ 0.02323	$ 0.04006	$ 0.03231	$ 0.01592
February 1, 2024	$ 0.03377	$ 0.03374	$ 0.03323	$ 0.04221	$ 0.02652	$ 0.02539	$ 0.04381	$ 0.03533	$ 0.01738
March 1, 2024	$ 0.03659	$ 0.03656	$ 0.03601	$ 0.04575	$ 0.02873	$ 0.02750	$ 0.04749	$ 0.03829	$ 0.01882
April 1, 2024	$ 0.03563	$ 0.03560	$ 0.03507	$ 0.04454	$ 0.02798	$ 0.02679	$ 0.04624	$ 0.03728	$ 0.01834
May 1, 2024	$ 0.03876	$ 0.03873	$ 0.03814	$ 0.04846	$ 0.03044	$ 0.02914	$ 0.05029	$ 0.04055	$ 0.01996
June 1, 2024	$ 0.03653	$ 0.03649	$ 0.03595	$ 0.04567	$ 0.02868	$ 0.02746	$ 0.04740	$ 0.03822	$ 0.01880
July 1, 2024	$ 0.03787	$ 0.03783	$ 0.03726	$ 0.04737	$ 0.02971	$ 0.02844	$ 0.04917	$ 0.03962	$ 0.01943
August 1, 2024	$ 0.03665	$ 0.03662	$ 0.03607	$ 0.04584	$ 0.02877	$ 0.02753	$ 0.04759	$ 0.03835	$ 0.01883
September 1, 2024	$ 0.03377	$ 0.03375	$ 0.03324	$ 0.04224	$ 0.02652	$ 0.02538	$ 0.04384	$ 0.03535	$ 0.01736
October 1, 2024	$ 0.03208	$ 0.03204	$ 0.03156	$ 0.04011	$ 0.02518	$ 0.02410	$ 0.04163	$ 0.03356	$ 0.01649
November 1, 2024	$ 0.02098	$ 0.02097	$ 0.02065	$ 0.02624	$ 0.01648	$ 0.01577	$ 0.02723	$ 0.02196	$ 0.01080
December 1, 2024	$ 0.01985	$ 0.01984	$ 0.01953	$ 0.02483	$ 0.01559	$ 0.01492	$ 0.02577	$ 0.02078	$ 0.01022

TRUE-UP FACTORS FOR THE PERIOD FROM JANUARY 1, 2024 TO DECEMBER 31, 2024 (DOLLAR PER KWH)

Annual true-up filing
(true-up factors proposed for April 2025 – March 2026)

	Residential	C&I Non-Demand	C&I Demand			Outdoor Lighting	General Time of Use Service Pilot Program		
			Non-TOD	TOD					
				On-Peak	Off-Peak		On-Peak	Base	Off-Peak
April 2025	$ (0.00227)	$ (0.00227)	$ (0.00224)	$ (0.00284)	$ (0.00178)	$ (0.00171)	$ (0.00295)	$ (0.00238)	$ (0.00117)
May 2025	$ (0.00203)	$ (0.00203)	$ (0.00200)	$ (0.00254)	$ (0.00159)	$ (0.00152)	$ (0.00263)	$ (0.00212)	$ (0.00104)
June 2025	$ (0.00177)	$ (0.00177)	$ (0.00175)	$ (0.00222)	$ (0.00139)	$ (0.00133)	$ (0.00230)	$ (0.00186)	$ (0.00091)
July 2025	$ (0.00150)	$ (0.00150)	$ (0.00147)	$ (0.00187)	$ (0.00118)	$ (0.00113)	$ (0.00194)	$ (0.00157)	$ (0.00077)
August 2025	$ (0.00158)	$ (0.00158)	$ (0.00155)	$ (0.00198)	$ (0.00124)	$ (0.00119)	$ (0.00205)	$ (0.00165)	$ (0.00081)
September 2025	$ (0.00193)	$ (0.00192)	$ (0.00190)	$ (0.00241)	$ (0.00151)	$ (0.00145)	$ (0.00250)	$ (0.00202)	$ (0.00099)
October 2025	$ (0.00200)	$ (0.00200)	$ (0.00197)	$ (0.00250)	$ (0.00157)	$ (0.00150)	$ (0.00259)	$ (0.00209)	$ (0.00103)
November 2025	$ (0.00206)	$ (0.00206)	$ (0.00203)	$ (0.00257)	$ (0.00162)	$ (0.00155)	$ (0.00267)	$ (0.00215)	$ (0.00106)
December 2025	$ (0.00182)	$ (0.00182)	$ (0.00180)	$ (0.00228)	$ (0.00143)	$ (0.00137)	$ (0.00237)	$ (0.00191)	$ (0.00094)
January 2026	$ (0.00174)	$ (0.00174)	$ (0.00172)	$ (0.00218)	$ (0.00137)	$ (0.00131)	$ (0.00226)	$ (0.00182)	$ (0.00090)
February 2026	$ (0.00201)	$ (0.00201)	$ (0.00198)	$ (0.00251)	$ (0.00158)	$ (0.00151)	$ (0.00261)	$ (0.00210)	$ (0.00103)
March 2026	$ (0.00183)	$ (0.00183)	$ (0.00181)	$ (0.00229)	$ (0.00144)	$ (0.00138)	$ (0.00238)	$ (0.00192)	$ (0.00094)

This Schedule of Fuel Adjustment Clause Factors is based on the requirements of the Minnesota Public Utilities Commission (the "Commission") Rules 7825.2700 to 7825.2820 governing automatic adjustment of energy charges, and with the Fuel Clause Riders and Dockets as defined on Sheet Nos. 5-91, 5-91.1, 5.-91.3 of the electric rates filed by the Company with the Commission, including Commission Revisions.

Miscellaneous Purchased Power Reporting

1. Renewable Energy Purchase Agreement (REPA) with KODA Energy, LLC (Docket No. E002/M-08-1098)

The Company is required to report in this annual report whether Xcel Energy has obtained any revenue from any source as a result of this REPA and to itemize any such revenues by source and amount. As of the 2024 reporting period, the Company has not received any new revenue as described in this Order. The Company will continue to monitor and report any such revenue in future true-up reports.

2. HERC PPA (Docket No. E002/M-17-532)

In a February 1, 2018 letter filed in Docket No. E002/M-17-532, the Company committed to provide the Commission with additional supporting information about the interim costs associated with the HERC PPA.

By way of background, the NSP-HERC PPA dated August 1, 1986, as amended, provides that HERC may offer the output of the plant to NSP for an additional seven years (January 1, 2018 through December 31, 2024) at its fair market value to NSP at the time it is offered. The Commission's December 28, 2017 Order in Docket No. E002/M-17-532 did not approve certain prices negotiated by the parties. Pursuant to the PPA, in May 2018 HERC notified NSP that it desired to arbitrate the pricing for the seven-year extension term (Extension Term).

Pending resolution of permanent pricing for the Extension Term, the parties entered into an interim agreement (Interim Agreement) in which NSP purchased HERC's energy during 2018 at the day-ahead MISO Locational Marginal Price (LMP) at the NSP.ALDRIHERC node as adjusted for any applicable MISO market charges and real time settlement differences (LMP Pricing). NSP and HERC entered into an amendment to the Interim Agreement on October 20, 2020, which extended the Interim Agreement through December 31, 2021. LMP pricing was used throughout the 2021 calendar year AAA reporting period.

On April 1, 2021 a decision was rendered in the arbitration case in favor of NSP that the fair market value of HERC's energy during the Extension Term is LMP Pricing. NSP and HERC subsequently entered into an Extension Amendment to the HERC PPA dated November 22, 2021 agreeing that LMP Pricing applies to energy sold by

HERC to NSP during the Extension Term and that no retroactive adjustment to the LMP Pricing of energy previously sold to NSP during the Extension Term is required.

Part C, Attachment 7 shows the production and invoiced amounts under the HERC Extension Amendment for the 2024 calendar year. The total cost paid during reporting period was $5.4 million, which is an average cost of $26.83/MWh.

3. Offsetting Revenues or Compensation Resulting from Contracts, Investments Paid for by Ratepayers

The Commission's April 6, 2012 ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS in Docket Nos. E999/AA-09-961 and E999/AA-10-884, the 2009 and 2010 AAA report dockets, requires the Company to report in future AAA filings any offsetting revenues or compensation recovered as a result of contracts, investments, or expenditures paid for by their ratepayers.

As of the 2024 reporting period, all applicable offsetting revenues and/or compensation resulting from fuel and purchased energy related contracts, investments, and expenditures paid for by ratepayers are credited back to ratepayers through the fuel clause. There were no credits during the 2024 reporting period.

Renewable*Connect Neutrality Charge
(Docket No. E002/M-15-985)

The Commission's February 27, 2017 Order in Docket No. E002/M-15-985, approving the Company's Renewable*Connect program, requires the Company to "provide in its Annual Automatic Adjustment reports a separate section discussing the pilot programs' impact on non-participants and the effectiveness of the neutrality charge to address any cost shift between participants and nonparticipants." This analysis only includes the pilot program.

To test the effectiveness of the Company's neutrality charge, the Company reviewed the actual system impact of the resources across the identified categories. Line losses, which accounted for approximately 60 percent of neutrality expenses in 2024, were the most significant impact across the cost categories as illustrated in Table 1 below. Curtailments on program solar resources totaled approximately $258,000, and $37,305 were allocated to the program. Wind curtailments associated with the program's wind resource increased in 2024. Wind curtailments totaled approximately $2.5 million, and $301,649 were allocated to the program.

Wind integration cost rates provided in the Company's Dakota Range filing in Docket No. E002/M-17-694 were also used to estimate the cost of the integration of the program's wind resource. The analysis results in an estimate of approximately $178,000 in wind integration costs for the 2024 reporting period.

To understand the potential impact of the Renewable*Connect Program on non-participant energy cost, the Company performed an analysis that compared the marginal cost of energy: in this case, on- and off-peak LMP pricing to the PPA cost of solar and wind resources allocated to Renewable*Connect consistent with the analysis the Company performed for the prior annual compliance filing. Since Odell Wind and North Star Solar were originally procured for the Fuel Clause paying customers, moving this higher cost energy from the Fuel Clause to Renewable*Connect has a positive impact on non-participants.

Overall, neutrality payments fell short of participant cost by approximately $379,000 in 2024. However, over the life of the program, when factoring the economic benefit of moving the higher priced Odell Wind and North Star Solar from the Fuel Clause to Renewable*Connect, the net result is that non-participants have received roughly a $4.4 million benefit due to the Renewable*Connect program.

Table 1
Non-Participants Impact Renewable*Connect Pilot

(in $000s)	**Total**	**2024**	**2023**	**2022**	**2021**	**2020**	**2019**	**2018**	**2017**
Line Losses	$4,117	$498	$606	$712	$677	$641	$532	$359	$92
Solar Curtailments	$200	$37	$0	$43	$29	$66	$17	$4	$3
Wind Curtailments	$944	$302	$143	$148	$302	$35	$11	$4	$0
Economic/Balancing	$1,570	$178	$232	$240	$228	$230	$227	$185	$50
Total	$6,831	$1,015	$980	$1,143	$1,236	$973	$787	$552	$145
Neutrality Payments	$5,935	$636	$844	$900	$876	$891	$884	$717	$187
Non-Participant Cost/(Benefit)	$8,96	$379	$136	$243	$360	$82	($97)	($165)	($42)
Net Economic Cost/(Benefit)	($5,331)	($1,228)	($1,225)	$2,168	$566	($2,889)	($1,792)	($688)	($244)
Total Cost/(Benefit)	($4,436)	($850)	($1,088)	$2,411	$926	($2,807)	($1,889)	($853)	($286)

Unusual Items Over $500,000
(Docket Nos. E999/AA-09-961, E999/AA-10-884 and E999/AA-18-373)

The Commission's April 6, 2012 ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS in Docket Nos. E999/AA-09-961 and E999/AA-10-884 (the 2008-2009 and 2009-2010 AAA report dockets) requires the Company to provide footnotes in future monthly FCA filings and future AAA filings to explain unusual adjustments of $500,000 and higher on a going forward basis. In addition, the Commission's November 13, 2019 Order in Docket No. E999/AA-18-373 (the 2017-2018 AAA report docket) requires the Company to identify and include error reports in future AAA filings and annual FCA true-up filings under the new FCA reform process. Table 1 below describes any such unusual items or errors on a system-wide basis during the 2024 reporting period.

Table 1
Unusual Items Over $500,000

Item Pertaining To	Period Affected	Descriptions	Amount (negative indicates cost decrease)	FCA Impact
MUFG Rail Car Lease Return	Mar-24 Jun-24	The lease for 216 coal rail cars expired on 2/29/2024. The net payment due upon termination was $2.6M. Over the term of the lease, NSPM accrued $3.3M as the expected termination payment. Accordingly, a credit of $0.5M and $0.2M was recorded to reduce coal expense in March 2024 and June 2024, respectively, in true-up of the final lease amounts.	($0.7M)	Yes
Fillmore	Jun-24	Fillmore is a new Solar PPA that was added to the Renewable Connect Flex program. Fillmore Solar was initially coded as standard solar and thus costs were initially included in the FCA. Past production was reclassified to Renewable*Connect in June. A total of $1.5M previously recorded in the FCA has been removed.	($1.5M)	Yes

Item Pertaining To	Period Affected	Descriptions	Amount (negative indicates cost decrease)	FCA Impact
Carleton College	Jul-24	A refund was received from Carleton College for the time-value of amounts received for unauthorized sales between April 16, 2006, the date the certification requirement for Qualifying Facilities went into effect, and September 26, 2011, the date Carleton College filed a Form 556 Self-Certification of Qualifying Facility Status for the 1.65 Mak wind turbine (FERC Docket QF11-511-000). The refund of $674,949.84 reduced purchased power expense in the month received.	($0.7M)	Yes
Black Dog and High Bridge Adjustment	Sep-24	As part of the NSPM gas lost and unaccounted review, a metering issue was identified that under-reported the gas consumption at Black Dog and High Bridge generating plants. As the generating plants and LDC share a TBS, the meter error resulted in a misallocation of gas costs between LDC and Generation. See Docket No. G999/AA-24-138 for more information.	$14M	Yes

The Commission's July 21, 2017 Order in Docket No. E999/AA-15-611 requires electric utilities to identify all dockets in which the Commission has granted rule variances to a utility's Fuel Clause Adjustment (such as those authorizing true-up provisions, those allowing costs of purchased power adjustments to flow through the FCA, and those allowing MISO costs and revenues to be included in the FCA). The variances and dockets pertaining to the 2024 Fuel Forecast True-Up reporting period are listed below. Any new Order issued or new activities since our last True-Up Report was filed have been underlined.

- Wind, Biomass and Others – E002/M-95-244, E002/M-96-934, E,G002/M-97-985, E002/M-17-530, E002/M-17-531, E002/M-17-532, E002/M-17-551, and E002/M-17-694
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    - Best Power, LLC, Amendment approved in E002/M-14-490, Order dated September 8, 2014
    - WM Renewable Energy, LLC, E002/M-10-161, Order dated April 30, 2010
    - Big Blue, LLC, Amendment approved in E002/M-13-1002, Order dated February 27, 2014.
    - Hilltop, E002/M-08-47, Notice of Approval dated February 15, 2008
    - Valley View, E002/M-08-1235, Order dated March 9, 2009
    - Ridgewind, E002/M-08-1428, Notice of Approval dated January 2, 2009
    - Moraine II, Amendment approved in E002/M-19-58, Order dated March 25, 2019
    - Ewington Energy Systems LLC, E002/M-06-1472, Notice of Approval dated November 30, 2006
    - Uilk Wind Farm, LLC, E002/M-08-1502, Notice of Approval dated February 6, 2009
    - Prairie Rose Wind, LLC, E002/M-11-713, Order dated December 28, 2011
    - Diamond K Dairy, E002/M-10-486, Order dated August 26, 2010
    - School Sisters, E002/M-15-619, Order dated September 14, 2015
    - Aurora Solar, E002/M-15-330, Order dated August 2, 2015
    - Marshall and NorthStar Solar, E002/M-14-162, Order dated March 24, 2015
    - Slayton Solar, E002/M-11-490, Order dated September 14, 2011
    - Dragonfly Solar, E002/M-17-561, Order dated October 12, 2017

  - o University of Minnesota South East Plant, E002/M-20-39, Order dated April 10, 2020
  - o Crowned Ridge and Clean Energy #1 – E002/M-16-777, Order dated September 1, 2017
  - o Dakota Range III – E002/M-18-765, Order dated July 19, 2019
  - o St. Paul Cogeneration – E002/M-21-590, Order dated January 24, 2022
- WindSource Exemption – E002/M-01-1479, E002/M-09-1177, Order dated June 21, 2010
- End-Of-Life Nuclear Fuel Accrual – E002/M-05-1648
- Community Solar Gardens Program – E002/M-13-867, Order dated May 30, 2024
- Renewable*Connect Government Program – E002/M-15-985
- Renewable*Connect – Docket No. E002/M-19-33
- Renewable*Connect – Docket Nos. E002/M-19-33 and E002/M-21-222, Order dated May 18, 2023
- Solar Energy Standard Exemption – E002/M-17-425, Order dated October 12, 2017
- Acquisition of Community Wind North and Jeffers Wind Facilities – E002/PA-18-777, Order dated December 3, 2019
- Becker Land Sale – E002/PA-23-110, Order dated April 12, 2023
- Red Wing Land Sale – E002/PA-23-118, Order dated May 2, 2023
- General Time of Use Service Pilot Program – Docket No. E002/M-20-86, Order dated February 1, 2023
- Legislative Changes to Community Solar Gardens – Docket No. E002/CI-23-335, Order dated December 28, 2023
- 2023-2024 Natural Gas Annual Automatic Adjustment of Charges and True-Up – Docket Nos. G002/AA-24-138 and G002/AA-304, Report filed September 3, 2024

Docket or Rule	Order Date	Rule or Order Point	Description	May 1, 2023 Annual Forecast of Rates	March 3, 2025 Annual True-Up Filing	Xcel Energy Disposition
Rule 7825.2800	NA	All public utilities shall file annually on September 1 of each year the procurement policies for selecting sources of fuel and energy purchased, dispatching policies, if applicable, and a summary of actions taken to minimize cost including conservation actions for gas utilities.	Policies and Actions: Fuel Procurement	Part D, Attachment 1	Part D, Attachment 1	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
			Nuclear Fuel Component of Service	Part D, Attachment 2	Part D, Attachment 2	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
			Coal Contracts	Part D, Attachment 3	Part D, Attachment 3	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
			Transportation & Related Services Contracts	Part D, Attachment 4	Part D, Attachment 4	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
			Wood and RDF Contracts	Part D, Attachment 5	Part D, Attachment 5	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
			Cost Changes	Part D, Attachment 6	Part D, Attachment 6	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
			Policies and Actions: Dispatching Policies and Procedures	Part D, Attachment 7	Part D, Attachment 7	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
			Policies and Actions: Fuel Supply	Part D, Attachment 8	Part D, Attachment 8	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
			Policies and Actions: Conservation and Load Management Policy	Part D, Attachment 9	Part D, Attachment 9	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
			Policies and Actions: Other Actions to Minimize Costs	Part D, Attachment 10	Part D, Attachment 10	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
Rule 7825.2810; E,G999/AA-04-1279	December 7, 2005	A. the commission-approved base cost of fuel or gas as defined by part 7825.2400, subpart 4 or 4a;	Annual Report of Automatic Adjustment Charges: Base Cost of Fuel	Part A, Attachment 1 and discussed in Petition	Report Narrative	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
Rule 7825.2810; E,G999/AA-04-1279		B. billing adjustment amounts, such as Kwh, Mcf, Ccf, or Btu, charged customers for each type of energy cost, such as nuclear, coal, purchased power, purchased gas by major component, peak shaving gas, or manufactured gas;	Annual Report of Automatic Adjustment Charges: Billing Adjustment Amounts Charged to Customers for Each Type of Energy Cost	Discussed in Petition	Part A	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
Rule 7825.2810; E,G999/AA-04-1279		D. the total cost of fuel or gas delivered to customers including, for gas utilities, the cost of supply-related services;	Annual Report of Automatic Adjustment Charges: Total Cost of Fuel Delivered to Customers	Discussed in Petition	Part A	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
Rule 7825.2810; E,G999/AA-04-1279		E. the revenues collected from customers for energy delivered;	Annual Report of Automatic Adjustment Charges: Revenue Collected from Customers for Energy Delivered	Discussed in Petition	Part A	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
Rule 7825.2810; E,G999/AA-04-1279		F. billing adjustments, supplier refunds, and any refunds credited to customers.	Annual Report of Automatic Adjustment Charges: Monthly Fuel Clause Adjustment	Part A, Attachment 1 and discussed in Petition	Part A, Attachment 4	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
Rule 7825.2820 Rule variance approved in E999/CI-03-802	NA	By September 1 of each year, all gas and electric utilities shall submit to the commission an independent auditor's report evaluating accounting for automatic adjustments for the prior year commencing July 1 and ending June 30 or any other year if requested by the utility and approved by the commission. The commission shall approve the request unless it finds that to do so would seriously affect the administration of the automatic adjustment reporting program.	Memo Engaging Auditor	NA	Part E, Attachment 1	Include with Annual True-Up filing aligned with calendar year reporting period.
			Independent Auditor's Report	NA	Part E, Attachment 2	Include with Annual True-Up filing
Rule 7825.2830 Rule variance approved in E999/CI-03-802	NA	By September 1 of each year, electric utilities shall submit to the commission a five-year projection of fuel costs by energy source by month for the first two years and on an annual basis thereafter.	5-Year Fuel Cost Forecast – Per Unit Summary	Part A, Attachment 1 Part E, Attachment 1	NA	Include with Annual Forecast of Rates filing
			5-Year Fuel Cost Forecast – Cost Summary	Part A, Attachment 2 Part E, Attachment 2	NA	Include with Annual Forecast of Rates filing
			5-Year Fuel Cost Forecast – Energy Summary	Part A, Attachment 3 Part E, Attachment 3	NA	Include with Annual Forecast of Rates filing
			Fossil Fuel Costs	Part B, Attachment 2	NA	Include with Annual Forecast of Rates filing
			Coal Burn Expenses	Part B, Attachment 3	NA	Include with Annual Forecast of Rates filing
			Nuclear Fuel Expenses	Part B, Attachment 4	NA	Include with Annual Forecast of Rates filing
			Peak Demand and Energy Requirements	Part A, Attachment 4 Part E, Attachment 4	NA	Include with Annual Forecast of Rates filing
			Estimated Load Management Impact	Part E, Attachment 5	NA	Include with Annual Forecast of Rates filing
Rule 7825.2840	NA	By September 1 of each year, all gas and electric utilities shall provide notice of the availability of the reports defined in parts 7825.2800 to 7825.2830 to all intervenors in the previous two general rate cases.	Notice of Reports Availability	Addendum to Petition	Part F, Attachment 7	Align with decisions for rules 7825.2800 through 7825.2831
E002/M-01-1953 and E,G/999-AA-02-950	March 20, 2002	Approved the Company's proposed method to separate, for accounting purposes, the costs and effects of financial instruments purchased to meet the needs of retail electric or natural gas ratepayers from the financial instruments purchased to mitigate price risk in the Company's non-jurisdictional wholesale electric sales activity.	Natural Gas Financial Instruments	NA	Report Narrative Part E, Attachments 1 and 2	Include with the Annual True-Up Filing.
E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/CN-01-1958, E002/M-04-864, E002/M-05-1850, E002/M-05-1934 and E002/M-06-85	July 17, 2002; October 4, 2004; December 27, 2022	Summarize curtailment events in its annual automatic adjustment (AAA) report; require Xcel to identify in its monthly fuel adjustment report the date, length, cost to ratepayers, and reason for each Voluntary Curtailment, all such events should be summarized in the Company's annual automatic adjustment (AAA) report.	Wind Curtailment Summary	NA	Part C, Attachment 2	Include with the Annual True-Up Filing by Curtailment Code (as in the past.) Combine with FCA Report Attachment 5A where curtailment is shown for each PPA.
E,G999/AA-04-1279	April 4, 2006	Track curtailments and curtailment payments that result from a lack of transmission capacity and report annually with Xcel's AAA information.	Wind Curtailment Report Narrative	Discussed in Petition Part G, Workpaper 10	Part C, Attachment 1	Eliminate, or reformat to provide information that more clearly ties to the Annual Forecast when there are forecasted potential increases in curtailment.
E002/M-08-1098	January 29, 2009	Xcel shall report in its annual automatic adjustment reports whether Xcel obtains any revenue from any source as result of the REPA and to itemize any such revenues by source and amount.	KODA PPA	NA	Part F, Attachment 1	Provide as needed to support Annual Forecast of Rates filing and Annual True-Up filing.
E002/M-13-867	September 17, 2014	Commission directed the Company to "include information about its bill credits, as reported in its Annual Compliance Report in this docket, in the Company's annual FCA Annual Automatic Adjustment (AAA) Report, reflecting the same time period covered by the AAA report.	Community Solar Gardens	Discussed in Petition Part B, Attachment 12 Part G, Workpapers 8 & 9	Part C, Attachments 8, 9, 10 Report Narrative	Include with Annual Forecast of Rates filing and Annual True-Up filing. Schedules may be reformatted to best suit the purpose of supporting the Forecast.

Docket or Rule	Order Date	Rule or Order Point	Description	May 1, 2023 Annual Forecast of Rates	March 3, 2025 Annual True-Up Filing	Xcel Energy Disposition
E999/AA-15-611	July 21, 2017	All electric utilities shall identify all dockets in which the Commission has granted rule variances to a utility's FCA (such as those authorizing true-up provisions, those allowing costs of purchased power adjustments to flow through the FCA, and those allowing MISO costs and revenues to be included in the FCA).	FCA Rule Variance Dockets	Discussed in Petition Part C, Attachment 2	Part F, Attachment 4	Provide as needed to support Annual Forecast of Rates filing and Annual True-Up filing.
E002/M-17-532	February 1, 2018	Letter whereby Xcel committed to provide the Commission with additional supporting information about the interim costs associated with the HERC PPA.	HERC	NA	Part F, Attachment 1	
E002/M-04-1970 E,G999/AA-06-1208 E002/GR-05-1428	December 20, 2006	Each utility shall file as part of its electric AAA report certain additional information regarding its plans with respect to acquiring fuel and purchased energy.	Summary of key factors affecting costs in the forecast, and plan for acquiring fuel and purchased energy.	Discussed in Petition	NA	Include with Annual Forecast of Rates filing.
E002/M-04-1970 E,G999/AA-06-1208	February 6, 2008	All electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, shall provide information requested by the Department in docket E,G-999/AA-07-1130 according to the spreadsheet attached to the 2007 Report pertaining to MISO Day 2 charges, one for every month in the AAA period and as a summary of MISO Day 2 charges for the entire AAA period, for a total of 13 pages in each utility's AAA filing.	Monthly MISO Day 2 charges and allocation	Discussed in Petition Part B, Attachment 8 Part F, Workpaper 5	Part B	Include with Annual Forecast of Rates filing and Annual True-Up filing, but we recommend reducing the number of formats and only including those that best meet the Consumer Advocate reviewers' needs.
E002/00-257, *et al.* E999/AA-11-792	May 9, 2002 August 16, 2013	Report, as part of its Annual Automatic Adjustment of Charges report (AAA) tiled under Minnesota Rules part 7825 2800, the following : a) The Schedule 10 administrative charges paid to the MISO under the MISO tariff, and b) Any amount of MISO administrative charge deterred by the MISO for later recovery.	Schedule 10 Administrative Charge Paid to MISO	NA	Part B, Attachment 1	
E002/M-08-528	August 23, 2010	The three utilities shall include costs and revenues from their participation in the MISO ancillary services market in future automatic adjustment reports filed under Minn. Rules, parts 7825.2390 et seq., including the annual filing required thereunder.	Annual and Daily Ancillary Services market charges and summary	NA	Part B	Include with the Annual True-Up Filing.
E,G999/AA-06-1208	February 6, 2008	All electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, shall include in future annual automatic adjustment filings the actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the utility's most recent rate case.	Generation facilities maintenance expenses	NA	Part C, Attachment 6	Include with the Annual True-Up Filing.
E999/AA-08-995	March 15, 2010	All electric utilities required to file annual automatic adjustment reports shall work with their contractors to identify and develop reasonable contingency plans to mitigate against the risk of delays or lack of performance when contractors perform poorly and increase costs during plant outages.	Contractor and supplier performance	NA	Part C, Attachment 3	Provide as needed to support Annual True-Up filing, or indicate there were no issues in the reporting period.
E999/AA-09-961 E999/AA-10-884	April 6, 2012	Xcel shall report in future AAA filings any offsetting revenues or compensation recovered by the utilities as a result of contracts, investments, or expenditures paid for by their ratepayers. If any offsetting revenues and/or compensation are not credited back to a utility's ratepayers through the fuel clause, the 6 IOUs shall clearly identify such revenues or compensation by source and amount and fully justify their action in the relevant AAA filings.	Offsetting Revenues and/or compensation Received by IOUs	NA	Part F, Attachment 1	Include with the Annual True-Up Filing.
E999/AA-08-995 E999/AA-10-884	April 6, 2012	The Commission requests Xcel to comment on sharing lessons learned regarding the handling of forced outages. The Commission also requests the companies to discuss amongst themselves whether and what kind of information sharing would be beneficial. The companies shall provide in supplemental filings to their fiscal-year 2011 AAA reports, in Docket No. E-999/AA-11-792, and in future AAA reports, a simple annual identification of forced outages and a short discussion of how such outages could have been avoided or alleviated.	Handling of forced outages	NA	Part C, Attachments 3, 4, 5	Include with the Annual True-Up filing.
E999/AA-09-961 E999/AA-10-884	April 6, 2012	Xcel shall provide footnotes in future monthly FCA filings and future AAA filings to explain unusual adjustments of $500,000 and higher on a going forward basis.	Unusual Adjustments over $500,000	NA	Part F, Attachment 3	Include with the Annual True-Up Filing.
E999/AA-18-373	November 13, 2019	Xcel shall identify and include error reports in future AAA filings and annual FCA true up filings under the new FCA reform process.				
E002/M-15-985	February 27, 2017	Xcel shall provide in its Annual Automatic Adjustment reports a separate section discussing the pilot programs' impact on non-participants and the effectiveness of the neutrality charge to address any cost shift between participants and nonparticipants.	Renewable*Connect Neutrality	Discussed in Petition Part G, Workpaper 14	Part F, Attachment 2	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
E002/AA-23-153	November 9, 2023	Required Xcel Energy to provide the following in its next FCA true-up petition: a. For each Xcel-owned wind facility, provide the assumed versus actual wind capacity factors for the true-up year and the three prior years showing capacity factors after curtailment. b. For each Xcel-owned wind facility, provide the assumed versus actual wind capacity factors for the true-up year and the three prior years showing capacity factors if no curtailment had occurred	Wind capacity factors and curtailment	NA	Part C, Attachment 2b	Include with the Annual True-Up Filing.
E002/AA-23-153	November 9, 2023	Required Xcel Energy to report on the prudency of its management of unplanned outages at Sherco 1, King, and Sherco 3 in Xcel's next FCA true-up petition.	Prudency of unplanned outages	NA	Part C, Attachment 3	

Docket or Rule	Order Date	Rule or Order Point	Description	May 1, 2023 Annual Forecast of Rates	March 3, 2025 Annual True-Up Filing	Xcel Energy Disposition
E999/CI-03-802	March 12, 2024	a comparison of the actual winter energy purchase amounts to the forecast amounts, with an explanation of a variance of five percent or greater.	Winter energy purchase variance	NA	NA	This reporting requirement does not apply to the NSP System.
E999/CI-03-802		The most recent three-year average of actual annual data compared to forecast for the FCA calculation components, generation costs, purchase costs, inter-system sales and outages.	Three-year average of actuals	NA	NA	Included with the Annual Forecast of Rates beginning with Docket No. E002/AA-24-63.
Recurring IR; E-002/AA-22-179	March 18, 2024	b. For outages specifically, please provide Xcel's actual planned and unplanned MWh's and energy cost due to outages for 3 calendar years on a total basis for each unit, in the same format as shown in the "Total" rows of Part C, Attachment 5 of the true-up report. Since this is a recurring IR, please continue to provide this information (with the years adjusted) in future FCA true-ups.	Planned and unplanned outages	NA	Part C, Attachments 5c and 5d	Include with Annual True-Up Filing.
Recurring IR; E-002/AA-22-179		c. One of the Department's recurring IRs is for spreadsheets underlying attachments/figures/tables; therefore the Department requests Xcel provide, in future FCA true-ups, spreadsheets for all tables and figures in the petition (including attachments), with links and formulas intact.	Provide live attachments	NA	Attachments provided as Informal IR	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
Recurring IR; E-002/AA-22-179		Please provide actual wind curtailments in MWh's for Company-owned facilities for 3 years, and year-to-date.	Curtailment - Company Owned	Part G, Attachment 9	Part C, Attachments 1 and 2	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
Recurring IR; E-002/AA-22-179		Provide Chart 2 in Part C, Attachment 1 to include Company-owned wind as well. Please include Company-owned wind in this chart going forward.		NA	Part C, Attachment 1	Include with the Annual Forecast of Rates filing and Annual True-Up Filing.
E002/AA-22-179	November 15, 2024	In future true-up petitions, Xcel must include the following information for planned outages: unit, outage category, primary reason for planned outage, outage start and end dates, duration in days, reason for planned outage, description of actions taken during outage, and change in energy costs due to outage.	Planned outage reporting	NA	Part C, Attachment 4b	Include with the Annual True-Up Filing.
E002/AA-20-891	November 7, 2022	Xcel must report in its fuel clause filing and annual automatic adjustment filings the amount of any curtailment, along with explanations for the curtailments, for the proposed Project.	Sherco Solar curtailment	NA	Part C, Attachment 2b	Include with the Annual True-Up Filing.
E002/AA-24-63	November 8, 2024	Required Xcel to provide the calculations of the proposed net cost of generation rate as an attachment in the fuel forecast dockets.	CSG/ Net cost of generation rate	NA	NA	Include with the Annual Forecast of Rates filing beginning with 2026 Forecast to be filed May 1, 2025.

TRADE SECRET JUSTIFICATION

Portions of this filing are marked "Not-Public" as they contain information the Company considers to be trade secret data as defined by Minnesota Statute § 13.37(1)(b). Per the statute, trade secret information is defined as including a compilation of government data that 1) was supplied by the affected individual or organization, 2) is subject of efforts by the individual or organization that are reasonable under the circumstances to maintain its secrecy, and 3) derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

The fuel supply, fuel cost, fuel cost forecast, and wind curtailment information designated as Not-Public Trade Secret information in this True-Up Report meets this definition for the following reasons:

1. This information meets the first criterion as it is submitted by Xcel Energy, which is an affected organization.

2. The information meets the second criterion in the statute because Xcel Energy makes extensive efforts to maintain the secrecy of this information. The information is not available outside of the Company except to (i) the other parties involved in the contracts subject to the non-disclosure provisions contained in the contracts, and (ii) regulatory agencies under the confidentiality provisions of state or federal law. This is evidenced by the non-disclosure provisions in the contracts.

3. The information meets the third criterion in the statute because the information has economic value to Xcel Energy, its customers, suppliers, and competitors. First, if suppliers knew the terms of Xcel Energy's electric and fuel supply and transportation contracts, they may be able to use this knowledge to fashion bids to Xcel Energy. While their bids may be competitive with existing contracts, they could be at a price higher than the best price the supplier can offer or the current market price. Second, suppliers will be reluctant to offer special favorable terms to Xcel Energy if they know other competitors or customers will gain knowledge of the terms and demand similar terms in the future. Third, competitors of Xcel Energy also purchase these services. These competitors may be able to leverage knowledge of Xcel Energy's costs to gain similar terms or may negotiate slightly better prices from

> the supplier. Any of these results would harm Xcel Energy and its customers. Because Xcel Energy competes for purchased energy, fuel and transportation services in a competitive marketplace, disclosure would directly harm Xcel Energy by making its delivered supply costs less competitive. The forecast of future fuel costs includes assumptions of future market prices for fuel not yet procured under contract. This information would give future potential suppliers knowledge of Xcel Energy's forecast of fuel prices that may not be the actual market price when procurement bids are requested. This knowledge may directly affect the prices submitted under bid or renegotiated during contract renewal.
>
> Contract confidentiality clauses in existing fuel supply contracts require suppliers' authorization prior to the release of any information pertaining to contract terms and conditions. Suppliers limit the public disclosure of this information to maintain their competitive position in the marketplace. Fuel and transportation services are not purchased in an open, commoditized marketplace. Prices are the result of closed bidding or direct negotiations and are not publicly available.

If our competitors knew our pricing information, they could use it to possibly extract advantageous terms from Xcel Energy or other suppliers, which would result in financial harm to Xcel Energy and its customers. For these reasons, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2024 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-23-153

NOTICE OF REPORT AVAILABILITY
ANNUAL TRUE-UP REPORT

On March 3, 2025, Northern States Power Company, doing business as Xcel Energy, filed a report with the Minnesota Public Utilities Commission for the 12 months ending December 31, 2024 involving the following MPUC Rules:

7825.2800 Annual Reports; Policies & Actions
7825.2810 Annual Report; Automatic Adjustment Charges
7825.2820 Annual Auditor's Report
7825.2830 Annual Five-Year Projection

Also included in the report are the MISO Day 2 and ASM compliance reporting requirements and additional fuel clause related reporting requirements under various Commission Orders.

The aforementioned report is available for public inspection at the MPUC offices, 121 East 7th Place, Suite 350 St. Paul, MN 55101-2147, on the Minnesota Department of Commerce edockets website (https://www.edockets.state.mn.us/EFiling) and upon written request to the following:

Xcel Energy
Regulatory Administration
414 Nicollet Mall – 401 7th Floor
Minneapolis, MN 55401

CERTIFICATE OF SERVICE

I, Joshua DePauw, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E002/AA-23-153
E002/GR-24-320
E002/GR-21-630

Dated this 3rd day of March 2025

/s/

Joshua DePauw
Regulatory Administrator

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Kevin	Adams	kadams@caprw.org	Community Action Partnership of Ramsey & Washington Counties		450 Syndicate St N Ste 35 Saint Paul MN, 55104 United States	Electronic Service		No	21-630Official
2	Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy		414 Nicollet Mall Fl 5 Minneapolis MN, 55401 United States	Electronic Service		No	21-630Official
3	Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy		414 Nicollet Mall7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	21-630Official
4	Jessica L	Bayles	jessica.bayles@stoel.com	Stoel Rives LLP		1150 18th St NW Ste 325 Washington DC, 20036 United States	Electronic Service		No	21-630Official
5	James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
6	Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
7	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	21-630Official
8	James	Canaday	james.canaday@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota St. St. Paul MN, 55101 United States	Electronic Service		No	21-630Official
9	John	Coffman	john@johncoffman.net	AARP		871 Tuxedo Blvd. St, Louis MO, 63119-2044 United States	Electronic Service		No	21-630Official
10	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	21-630Official
11	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	21-630Official
12	James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	21-630Official
13	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	21-630Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
14	Richard	Dornfeld	richard.dornfeld@ag.state.mn.us		Office of the Attorney General - Department of Commerce	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul MN, 55101 United States	Electronic Service		No	21-630Official
15	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	21-630Official
16	Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy		414 Nicollet Mall - 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	21-630Official
17	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-Reliance Minneapolis MN, 55406 United States	Electronic Service		No	21-630Official
18	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	21-630Official
19	Lucas	Franco	lfranco@liunagroc.com	LIUNA		81 Little Canada Rd E Little Canada MN, 55117 United States	Electronic Service		No	21-630Official
20	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	21-630Official
21	Allen	Gleckner	agleckner@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	21-630Official
22	Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY		401 Nicollet Mall FL 8 Minneapolis MN, 55401 United States	Electronic Service		No	21-630Official
23	Shubha	Harris	shubha.m.harris@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401 - FL 8 Minneapolis MN, 55401 United States	Electronic Service		No	21-630Official
24	Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall, 401-7 Minneapolis MN, 55401 United States	Electronic Service		No	21-630Official
25	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	21-630Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
26	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	21-630Official
27	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	21-630Official
28	Geoffrey	Inge	ginge@regintllc.com	Regulatory Intelligence LLC		PO Box 270636 Superior CO, 80027-9998 United States	Electronic Service		No	21-630Official
29	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	21-630Official
30	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
31	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
32	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
33	Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
34	Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.		8300 Norman Center Drive Suite 1000 Bloomington MN, 55437 United States	Electronic Service		No	21-630Official
35	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	21-630Official
36	Ryan	Long	ryan.j.long@xcelenergy.com			414 Nicollet Mall 401 8th Floor Minneapolis MN, 55401 United States	Electronic Service		No	21-630Official
37	Alice	Madden	alice@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	21-630Official
38	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc	Electronic Service		No	21-630Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						WI, 53066 United States				
39	Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc		414 Nicollet Mall 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	21-630Official
40	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	21-630Official
41	Greg	Merz	greg.merz@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	21-630Official
42	Joseph	Meyer	joseph.meyer@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Bremer Tower, Suite 1400 445 Minnesota Street St Paul MN, 55101-2131 United States	Electronic Service		No	21-630Official
43	Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis		350 S. 5th Street Room M 301 Minneapolis MN, 55415 United States	Electronic Service		No	21-630Official
44	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	21-630Official
45	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
46	Christa	Moseng	christa.moseng@state.mn.us		Office of Administrative Hearings	P.O. Box 64620 Saint Paul MN, 55164-0620 United States	Electronic Service		No	21-630Official
47	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
48	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	21-630Official
49	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	21-630Official
50	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	21-630Official
51	Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy		414 Nicollet Mall FL 5	Electronic Service		No	21-630Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Minneapoli MN, 55401 United States				
52	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
53	Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.		225 South Sixth Street Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
54	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	21-630Official
55	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall FL 7 Minneapolis MN, 55401-1993 United States	Electronic Service		No	21-630Official
56	Will	Seuffert	will.seuffert@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul MN, 55101 United States	Electronic Service		Yes	21-630Official
57	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN, 55423 United States	Electronic Service		No	21-630Official
58	Joshua	Smith	joshua.smith@sierraclub.org			85 Second St FL 2 San Francisco CA, 94105 United States	Electronic Service		No	21-630Official
59	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	21-630Official
60	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	21-630Official
61	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
62	Scott	Strand	sstrand@elpc.org	Environmental Law & Policy Center		60 S 6th Street Suite 2800 Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
63	James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
64	Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine		225 S 6th St Ste 3500 Capella Tower Minneapolis MN, 55402-	Electronic Service		No	21-630Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						4629 United States				
65	Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine		225 South Sixth Street, Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official
66	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	21-630Official
67	Patrick	Zomer	pat.zomer@lawmoss.com	Moss & Barnett PA		150 S 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	21-630Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Kevin	Adams	kadams@caprw.org	Community Action Partnership of Ramsey & Washington Counties		450 Syndicate St N Ste 35 Saint Paul MN, 55104 United States	Electronic Service		No	23-153AA-23-153
2	Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy		414 Nicollet Mall Fl 5 Minneapolis MN, 55401 United States	Electronic Service		Yes	23-153AA-23-153
3	Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy		414 Nicollet Mall7th Floor Minneapolis MN, 55401 United States	Electronic Service		Yes	23-153AA-23-153
4	Jessica L	Bayles	jessica.bayles@stoel.com	Stoel Rives LLP		1150 18th St NW Ste 325 Washington DC, 20036 United States	Electronic Service		No	23-153AA-23-153
5	James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153
6	Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153
7	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	23-153AA-23-153
8	James	Canaday	james.canaday@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota St. St. Paul MN, 55101 United States	Electronic Service		No	23-153AA-23-153
9	John	Coffman	john@johncoffman.net	AARP		871 Tuxedo Blvd. St, Louis MO, 63119-2044 United States	Electronic Service		No	23-153AA-23-153
10	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	23-153AA-23-153
11	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	23-153AA-23-153
12	James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	23-153AA-23-153
13	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		Yes	23-153AA-23-153

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
14	Richard	Dornfeld	richard.dornfeld@ag.state.mn.us		Office of the Attorney General - Department of Commerce	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul MN, 55101 United States	Electronic Service		No	23-153AA-23-153
15	Christopher	Droske	christopher.droske@minneapolismn.gov	Northern States Power Company dba Xcel Energy-Elec		661 5th Ave N Minneapolis MN, 55405 United States	Electronic Service		No	23-153AA-23-153
16	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	23-153AA-23-153
17	Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy		414 Nicollet Mall - 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		Yes	23-153AA-23-153
18	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-Reliance Minneapolis MN, 55406 United States	Electronic Service		No	23-153AA-23-153
19	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	23-153AA-23-153
20	Lucas	Franco	lfranco@liunagroc.com	LIUNA		81 Little Canada Rd E Little Canada MN, 55117 United States	Electronic Service		No	23-153AA-23-153
21	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	23-153AA-23-153
22	Allen	Gleckner	agleckner@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	23-153AA-23-153
23	Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY		401 Nicollet Mall FL 8 Minneapolis MN, 55401 United States	Electronic Service		Yes	23-153AA-23-153
24	Shubha	Harris	shubha.m.harris@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401 - FL 8 Minneapolis MN, 55401 United States	Electronic Service		Yes	23-153AA-23-153
25	Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall, 401-7 Minneapolis MN, 55401 United States	Electronic Service		No	23-153AA-23-153

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
26	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	23-153AA-23-153
27	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	23-153AA-23-153
28	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	23-153AA-23-153
29	Geoffrey	Inge	ginge@regintllc.com	Regulatory Intelligence LLC		PO Box 270636 Superior CO, 80027-9998 United States	Electronic Service		No	23-153AA-23-153
30	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	23-153AA-23-153
31	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153
32	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153
33	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153
34	Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153
35	Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.		8300 Norman Center Drive Suite 1000 Bloomington MN, 55437 United States	Electronic Service		No	23-153AA-23-153
36	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	23-153AA-23-153
37	Ryan	Long	ryan.j.long@xcelenergy.com			414 Nicollet Mall 401 8th Floor Minneapolis MN, 55401 United States	Electronic Service		Yes	23-153AA-23-153
38	Alice	Madden	alice@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis	Electronic Service		No	23-153AA-23-153

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55406 United States				
39	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	23-153AA-23-153
40	Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc		414 Nicollet Mall 7th Floor Minneapolis MN, 55401 United States	Electronic Service		Yes	23-153AA-23-153
41	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	23-153AA-23-153
42	Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis		350 S. 5th Street Room M 301 Minneapolis MN, 55415 United States	Electronic Service		No	23-153AA-23-153
43	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	23-153AA-23-153
44	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153
45	Christa	Moseng	christa.moseng@state.mn.us		Office of Administrative Hearings	P.O. Box 64620 Saint Paul MN, 55164-0620 United States	Electronic Service		No	23-153AA-23-153
46	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153
47	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	23-153AA-23-153
48	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	23-153AA-23-153
49	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	23-153AA-23-153
50	Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy		414 Nicollet Mall FL 5 Minneapoli MN, 55401 United States	Electronic Service		Yes	23-153AA-23-153
51	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
52	Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.		225 South Sixth Street Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153
53	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	23-153AA-23-153
54	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall FL 7 Minneapolis MN, 55401-1993 United States	Electronic Service		Yes	23-153AA-23-153
55	Will	Seuffert	will.seuffert@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul MN, 55101 United States	Electronic Service		Yes	23-153AA-23-153
56	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN, 55423 United States	Electronic Service		No	23-153AA-23-153
57	Joshua	Smith	joshua.smith@sierraclub.org			85 Second St FL 2 San Francisco CA, 94105 United States	Electronic Service		No	23-153AA-23-153
58	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	23-153AA-23-153
59	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	23-153AA-23-153
60	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153
61	James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153
62	Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine		225 S 6th St Ste 3500 Capella Tower Minneapolis MN, 55402-4629 United States	Electronic Service		No	23-153AA-23-153
63	Carla	Vita	carla.vita@state.mn.us	MN DEED		Great Northern Building 12th Floor 180 East Fifth Street St. Paul MN, 55101 United States	Electronic Service		No	23-153AA-23-153

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
64	Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine		225 South Sixth Street, Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153
65	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	23-153AA-23-153
66	Patrick	Zomer	pat.zomer@lawmoss.com	Moss & Barnett PA		150 S 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	23-153AA-23-153

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Kevin	Adams	kadams@caprw.org	Community Action Partnership of Ramsey & Washington Counties		450 Syndicate St N Ste 35 Saint Paul MN, 55104 United States	Electronic Service		No	24-320Official CC Service List
2	Justin	Andringa	justin.andringa@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
3	Katherine	Arnold	katherine.arnold@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
4	Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy		414 Nicollet Mall Fl 5 Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
5	Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy		414 Nicollet Mall7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
6	Jessica L	Bayles	jessica.bayles@stoel.com	Stoel Rives LLP		1150 18th St NW Ste 325 Washington DC, 20036 United States	Electronic Service		No	24-320Official CC Service List
7	James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
8	Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
9	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	24-320Official CC Service List
10	James	Canaday	james.canaday@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota St. St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
11	Olivia	Carroll	oliviac@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St W1360 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
12	John	Coffman	john@johncoffman.net	AARP		871 Tuxedo Blvd. St, Louis MO, 63119-2044 United States	Electronic Service		No	24-320Official CC Service List
13	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN,	Electronic Service		No	24-320Official CC Service List

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						55101 United States				
14	Brandon	Crawford	brandonc@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
15	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	24-320Official CC Service List
16	James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
17	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
18	Richard	Dornfeld	richard.dornfeld@ag.state.mn.us		Office of the Attorney General - Department of Commerce	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
19	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
20	Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy		414 Nicollet Mall - 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
21	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-Reliance Minneapolis MN, 55406 United States	Electronic Service		No	24-320Official CC Service List
22	Eden	Faure	eden.faure@stoel.com	Stoel Rives LLP		33 S. 6th Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
23	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	24-320Official CC Service List
24	Lucas	Franco	lfranco@liunagroc.com	LIUNA		81 Little Canada Rd E Little Canada MN, 55117 United States	Electronic Service		No	24-320Official CC Service List

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25	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	24-320Official CC Service List
26	Allen	Gleckner	agleckner@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	24-320Official CC Service List
27	Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY		401 Nicollet Mall FL 8 Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
28	Shubha	Harris	shubha.m.harris@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401 - FL 8 Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
29	Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall, 401-7 Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
30	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	24-320Official CC Service List
31	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	24-320Official CC Service List
32	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	24-320Official CC Service List
33	Amrit	Hundal	amrit.hundal@ag.state.mn.us		Office of the Attorney General - Department of Commerce		Electronic Service		No	24-320Official CC Service List
34	Geoffrey	Inge	ginge@regintllc.com	Regulatory Intelligence LLC		PO Box 270636 Superior CO, 80027-9998 United States	Electronic Service		No	24-320Official CC Service List
35	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	24-320Official CC Service List
36	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
37	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List

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38	Samuel B.	Ketchum	sketchum@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
39	Brad	Klein	bklein@elpc.org	Environmental Law & Policy Center		35 E Wacker Drive Suite 1600 Chicago IL, 60302 United States	Electronic Service		No	24-320Official CC Service List
40	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
41	Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
42	Amber	Lee	amber.lee@stoel.com	Stoel Rives LLP		33 S. 6th Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
43	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
44	Ryan	Long	ryan.j.long@xcelenergy.com			414 Nicollet Mall 401 8th Floor Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
45	Alice	Madden	alice@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	24-320Official CC Service List
46	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	24-320Official CC Service List
47	Robert	Manning	robert.manning@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 Saint Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
48	Ashley	Marcus	ashley.marcus@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
49	Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc		414 Nicollet Mall 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
50	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL,	Electronic Service		No	24-320Official CC

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						60601 United States				Service List
51	Greg	Merz	greg.merz@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
52	Joseph	Meyer	joseph.c.meyer@state.mn.us		Office of Administrative Hearings	PO Box 64620 St. Paul MN, 55164 United States	Electronic Service		Yes	24-320Official CC Service List
53	Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis		350 S. 5th Street Room M 301 Minneapolis MN, 55415 United States	Electronic Service		No	24-320Official CC Service List
54	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	24-320Official CC Service List
55	Hirsi	Mohamed	hirsi.mohamed@state.mn.us		Public Utilities Commission	121 7th Place E, Suite 350 Saint Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
56	Marta	Monti	marta@energycents.org	Energy CENTS Coalition		823 E. 7th Street St. Paul MN, 55106 United States	Electronic Service		No	24-320Official CC Service List
57	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
58	Christa	Moseng	christa.moseng@state.mn.us		Office of Administrative Hearings	P.O. Box 64620 Saint Paul MN, 55164-0620 United States	Electronic Service		No	24-320Official CC Service List
59	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
60	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	24-320Official CC Service List
61	Wendy	Raymond	wendy.raymond@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota Street Suite 600 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
62	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		No	24-320Official CC Service List
63	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental		26 E Exchange St,	Electronic Service		No	24-320Official

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				Advocacy		Ste 206 St. Paul MN, 55101-1667 United States				CC Service List
64	Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy		414 Nicollet Mall FL 5 Minneapoli MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
65	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
66	Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.		225 South Sixth Street Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
67	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	24-320Official CC Service List
68	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall FL 7 Minneapolis MN, 55401-1993 United States	Electronic Service		No	24-320Official CC Service List
69	Will	Seuffert	will.seuffert@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
70	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN, 55423 United States	Electronic Service		Yes	24-320Official CC Service List
71	George	Shardlow	george@energycents.org	Energy CENTS Coalition		823 E. 7th Street Saint Paul MN, 55106 United States	Electronic Service		No	24-320Official CC Service List
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73	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	24-320Official CC Service List
74	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	24-320Official CC Service List
75	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
76	Scott	Strand	sstrand@elpc.org	Environmental Law & Policy Center		60 S 6th Street Suite 2800	Electronic Service		No	24-320Official CC

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						Minneapolis MN, 55402 United States				Service List
77	James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
78	Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine		225 S 6th St Ste 3500 Capella Tower Minneapolis MN, 55402-4629 United States	Electronic Service		No	24-320Official CC Service List
79	Anthony	Willingham	anthony.willingham@electrifyamerica.com	Electrify America		1950 Opportunity Way Suite 1500 Reston VA, 20190 United States	Electronic Service		No	24-320Official CC Service List
80	Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine		225 South Sixth Street, Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
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82	Patrick	Zomer	pat.zomer@lawmoss.com	Moss & Barnett PA		150 S 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List